Alaska Department of Environmental Conservation

Amendments to:
State Air Quality Control Plan Vol. III:

Appendix III.D.7.07

{Appendix to Volume II. Analysis of Problems, Control Actions; Section III. Area-wide Pollutant Control Program; D. Particulate Matter; 7. Fairbanks North Star Borough PM2.5 Control Plan, Serious Requirements}

Draft

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Appendix III.D.7.07

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Evidence of Implementation of Moderate SIP control Measures.

Under the PM2.5 Implementation Rule, 40 CFR 51.1005(b)(1)(ii), the State is required to show evidence of implementation of all control measures submitted in the applicable plan.[1] Table 7.7-1 in the Serious SIP Section III.D.7.7.3 summarizes the Moderate SIP control measures and their implementation status. The detailed information on the implementation of the Moderate SIP control measures with the status is explained in this appendix document.

7.7.3.1 Solid Fuel-Fired Heating Device Upgrades

Solid fuel-fired heating device upgrades, also called the Wood Stove Change-Out Program (WSCOP) or Fairbanks North Star Borough (FNSB) Enhanced Voluntary Removal, Replacement & Repair Program, is a voluntary incentivized control measure aimed at upgrading or removing solid fuel-fired heating devices to provide immediate and long-term reductions of $PM_{2.5}$ emissions in the nonattainment area. The program, which was started in 2010 and still ongoing, is reinforced with funds from the Targeted Air Shed (TAS) Grants.

Although the Borough suspended the wood stove change-out program because of the passage of the Voter Proposition 4 on October 2, 2018, the program was reinstated after making necessary changes to the Borough's code. The wood stove change-out program includes requirements that are more stringent than the Alaska Department of Environmental Conservation (DEC) standards. However, they only apply to the Borough's air quality control zone. Borough ordinance 2015-73, adopted January 14, 2016, limits the change-out program to the air quality control zone and sets emission limits for solid fuel-fired heating devices installed as part of the change out program. Borough ordinance 2017-44, adopted June 19, 2017, requires that a Borough listed vendor/installer properly installs a qualified appliance. The ordinance requires that wood and pellet stoves must be EPA-certified with an annual average $PM_{2.5}$ emission rating of 2.0 grams per hour or less. Hydronic heaters must be pellet-fired, EPA-certified, and have an emission rate of 0.10 pounds per million BTU or less.[2] These emission standards are designed to adopt EPA's wood-fired heater New Source Performance Standards (NSPS) 2020 emission limits early for devices installed as part of the change out program.

Also, in order to ensure that replacements of wood-fired heaters are moving the solid fuel-fired devices within the Fairbanks nonattainment area toward the NSPS 2020 emission limits, the terms and conditions of the Targeted Air Shed Grant, as stated in the work plan, require an average emission level of 0.10 pounds per million BTU and particulate matter annual average emission limit of 2.0 grams per hour.[3] Tables 7.7.3-1 and 7.7.3-2 display the eligible devices for replacements and replacement options and emission limits respectively.

Table 7.7.3-1. Eligible Devices and Replacements

[1] 40 CFR 51.1005

[2] Fairbanks North Star Borough Ordinance No. 2017-44, adopted June 19, 2017

[3] FY-16 TAS Work Plan

Device Type	Eligibility Requirement		Replacement Option
Hydronic Heater	All Wood or Coal Hydronic Heaters		1,2,3,4,5,6,7,8
Wood or Coal Stove	Non EPA-Certified	EPA-Certified ≥ 2.5 g/hr (new device must also be less than half of old device emission rating)	1,2,4,5,6,7,8
	EPA-Certified Wood Stove (Repair)		9,10
Fireplace	All Fireplaces		1,2,3,4,5,6,7,8

Table 7.7.3-2 Replacement Options and Emission Limits

Replacement Option			Emission Limit
1	EPA-Certified	Catalyst – Equipped Wood Stove or Catalyst-Equipped Insert	≤ 2.0 g/hr
2		Pellet Stove or Insert	
3		Pellet Hydronic Heater	≤ 0.10 lbs/mmBtu
4	Home Heating Oil Heater		
5	Hot Water District Heat		
6	Electric Heater		
7	Natural Gas Device		
8	Propane Device		
9	Catalytic Converter Repair		
10	Other Emission Reduction System Component Repair		

To date, a total of 164 change outs have been completed with funds from the FY-16 TAS and FY-17 TAS; 163 change outs from the FY-16, and one change out from the FY-17.[4,5,6] However, as of March 31, 2019, as displayed in Table 7.7.3-1, a total of 2,636 change outs out of the 2,760 change-outs required by the Moderate Area SIP have been completed. Figure 7.7.3-3 provides a map of the locations of change outs or heater removals throughout the nonattainment area from January 2018 through April 15, 2019.

Table 7.7.3-3. Woodstove Change-Out Statistics

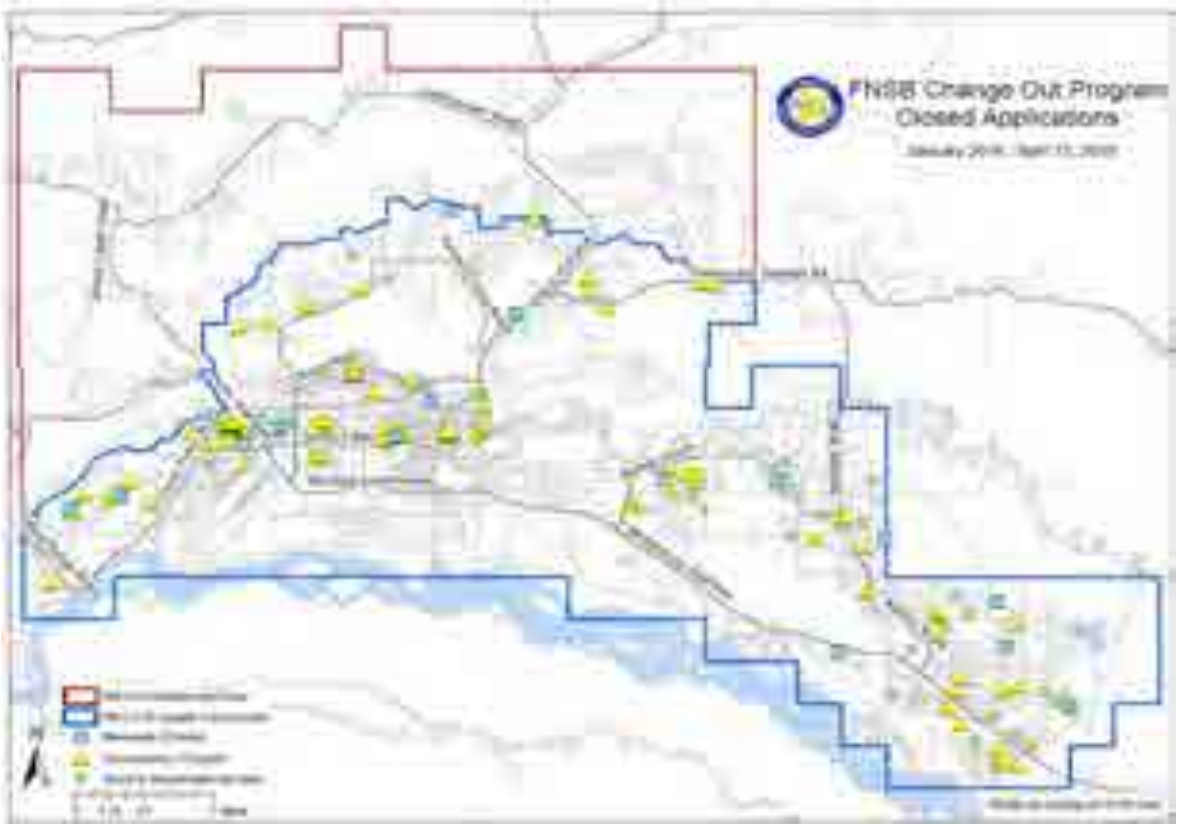
Woodstove Change Out Statistics (as of 3/31/2019)		
Device Type	**Total Devices Removed, Replaced, or Repaired**	**Percentage of Total Change outs**
Replace Solid Fuel Burning Device	1925	73.0%
Replace Hydronic Heater (HH)	86	3.3%
Removal of SFBA (not replaced)	237	9.0%
Removal of Hydronic Heater (not replaced)	110	4.2%
Repairs to EPA certified Devices	75	2.8%
Fireplace Replacements	203	7.7%

Figure 7.7.3-1. Map of the locations of change outs or heater removals throughout the nonattainment area.

[4] Wood Stove Change Out Program 2018-2019 Brief Statistics

[5] FY-16 TAS-01 2019 1st Quarter Report

[6] FY-17 TAS-01 2019 1st Quarter Report



7.7.3.2 Solid Fuel-Fired Heating Device Emission Standards

In order to provide support for the WSCOP and ensure commitments to the Moderate Area SIP control measure, the State, in 2014, adopted a new regulation that requires all the new wood-fired heating devices being installed in the Fairbanks nonattainment area to meet emission standards (Table 7.7.3-4) that are more stringent than the 1988 EPA New Performance Standards (NSPS).[7]

Table 7.7.3-4. DEC Emission Standards for Wood-Fired Heating Devices in the Fairbanks Nonattainment Area

Device Type	$PM_{2.5}$ Emission Standard
Woodstoves	2.5 grams/hour
Wood Hydronic Heaters	2.5 grams/hour
Wood Heating Appliances Greater than 350,000 btu/hr heat output	2.5 grams/hour

The Borough's change out requirements (Table 7.7.3-5) mirrors the EPA's wood-fired heater NSPS 2020 emission limits. However, for home heating device installations that are not part of the change out program, the Borough requirements were that all the solid fuel-fired appliances be EPA-certified and have an annual average emission rating of 2.5 grams per hour or less or 0.10

[7] 18 AAC 50.077

pounds per million BTU for hydronic heaters. However, since the removal of the Borough's authority, the State emission standards have continued to apply to solid fuel-fired heating devices in the Fairbanks nonattainment area to ensure the continued implementation of the Moderate SIP control measure. The requirements of the Targeted Airshed Grant for the Borough change out program continue to ensure that devices installed through the program meet levels mirroring the EPA's wood-fired heater NSPS 2020 emission certification limits.

Table 7.7.3-5. FNSB WSCOP Emission Standards for Wood-Fired Heating Devices

Device Type	$PM_{2.5}$ Emission Standard
Wood and Pellet stoves (EPA-certified)	2.0 grams/hour
Pellet-fired Hydronic Heaters (EPA-certified)	0.10 Ibs/mmBtu or less

7.7.3.3 Improving Solid Fuel-Fired Heating Device Operations

Improving the operations of solid fuel-fired heating devices was one of the voluntary measures identified in the Moderate SIP. To achieve this, the Borough and DEC developed a number of measures, including public education, incentives for the use of wood pellets or energy logs, regulations addressing visible emissions from stacks, and the use of appropriate fuels in solid fuel-fired heating devices. The extensive public outreach is intended to encourage residents to employ the best burning practices when using wood heating devices, protect themselves, and to reduce $PM_{2.5}$ emissions in Fairbanks nonattainment area. Examples of the public outreach include the ''Split, Stack, Store, & Save" campaign and the repealed Voluntary Burn Cessation Program (VBCP). The education outreach, which is tailored to the individual needs, is propagated through TV/YouTube ad topics, Radio ad topics, web-based outreach, print-based media, public presentations, events, and other outreach methods.

Some of the Borough's education outreach activities such as mass notification of alerts, electronic signs for air quality alerts, a notice of restrictions, and notifications of violations have since been discontinued due to the passage of Prop 4. However, the DEC programs and regulations that promote the use of correct fuels have continued to facilitate the implementation of the Moderate SIP control measure. To assure that wood heating devices are being operated properly, the DEC regulations in 18 AAC 50.075, as amended in 2017, requires a 20% opacity requirement for all solid-fuel fired heating devices.[8] This opacity requirement mirrors the FNSB ordinance in that the 20% opacity is for all operations except at startup. This standard reflects improvements in wood heating technology and the need to burn cleanly particularly during air quality episodes. If devices are operated improperly or with wet wood, dense smoke can be emitted from stacks. The opacity regulations for wood-fired heating devices assist DEC in responding to citizen complaints about smoky stacks in their neighborhoods and in addressing high emitting devices, particularly during periods of poor air quality.

[8] 18 AAC 50.075

Also, to further support the efforts to reduce emissions through the proper operation of solid fuel-fired devices inside the nonattainment area, the State regulation, 18 AAC 50.076, as amended through September 15, 2018, requires individuals to use the appropriate fuel (wood or coal) in their device and use of dry wood (20% moisture content or less) in the winter months.[9] Until the FNSB authority was removed in October 2, 2018, the Borough's ordinance, which was adopted on February 27, 2015, required the use of dry wood year round.

7.7.3.4 Reduced Use of Solid Fuel-Fired Heaters during Air Pollution Episodes

Until the passage of Prop 4 on October 2, 2018, FNSB worked together with DEC to forecast daily air quality during the winter and issue curtailment of the use of wood-fired heating devices in the Fairbanks nonattainment area on days projected to have poor dispersion and higher $PM_{2.5}$ concentrations. To enforce compliance with the control measure, the Borough, through the local media, notified the public of air alerts, why they were called, and provided residents with options. Table 7.7.3-6 below displays the FNSB air quality episode thresholds and exceptions.

Table 7.7.3-6. FNSB Air Quality Episode Thresholds and Exceptions

Episode Feature	Stage 1 Air Alert	Stage 2 Air Alert
$PM_{2.5}$ Threshold, micrograms per cubic meter, ($\mu g/m^3$)	25	35
Exceptions During a Power Outage	Yes	Yes

In its code the Borough allowed property owners or managers to obtain a "No Other Adequate Source of Heat" (NOASH) waiver to all stages of burn cessation requirements if the property relies on a solid fuel-fired heating device as its sole source of heat, or if compliance with the burn restrictions would result in property damage, or that economic hardships required the applicant's use of a solid fuel-fired heating device. Applicants were only eligible for a NOASH if the solid fuel-fired heating device was borough listed. Ordinance 2016-37 strengthened the NOASH by limiting the waiver eligibility to properties constructed before December 31, 2016, to ensure no new construction occurs that would be eligible for a NOASH waiver. Ordinance 2017-18 further strengthened the curtailment program by replacing the three stage system with a two stage curtailment. The voluntary curtailment was discontinued and mandatory curtailments were lowered from 55 □g/m^3 to 35 □g/m^3 (Stage 2) and 35 □g/m^3 to 25 □g/m^3 (Stage 1). Ordinance 2017-18 also removed the temperature exemption of -15^{O}F as recorded at the Fairbanks International Airport. Ordinance 2017-44 further strengthened the curtailment program by requiring a Stage 1 Waiver to be obtained by a property owner or manager who verifies that the solid fuel burning appliance (SFBA) operated during a Stage 1 air alert is a borough listed appliance, thereby making Stage 1 curtailments enforceable. NOASH and Stage 1 waiver applicants were also urged to participate in the Borough's change-out program to help reduce emissions.

[9] 18 AAC 50.076

Also, FNSB used the Voluntary Burn Cessation Program (VBCP) until it was repealed in 2017 to encourage, incentivize, and facilitate the voluntary cessation of the use of wood burning appliances in the nonattainment area during air quality episodes. The Borough conducted the VBCP through five separate components; an Alert System, Social Media, Public Awareness, Marketing, and Incentive program.

Table 7.7.3-7 displays the number of Stage restriction called by FNSB for the 2017/2018 heating season. A restriction day is defined as a 24-hour period during which the area was under a stage restriction for more than 12 hours, e.g. if a Stage 2 was in effect from 4:00 pm Monday through 4:00 pm on Wednesday then the event would be logged as two restriction days (Tuesday and Wednesday would count). Restrictions warranted were based on the real-time BAM data for each respective area, and if the BAM data indicated a 24-hour average was above the threshold for a Stage 1 or a Stage 2 then the day was logged as warranted. The Borough issued a total number of 244 Stage 1 waivers and 125 NOASH waivers for 2017/2018 heating season. As shown in Table 7.7.3-8, there were 105 observed violations for Stage 1 for which 90 warning letters were sent while for Stage 2, there were 137 violations for which 111 warning letters were sent.[10] After the first warning letter sent, the FNSB Mayor's office would make personal contact with the letter recipient. Repeat violations would result in a second warning letter, and a third violation would result in issuance of a citation. A total of two citations were issued during the winter of 2017/2018, one for a Stage 1 violation and one for a Stage 2 violation.

Table 7.7.3-7. Number of Stage restriction days called by FNSB during 2017/2018 heating Season

	Stage 2	Stage 1
North Pole		
Restriction Called	28	8
Restriction Warranted	41	9
Fairbanks		
Restriction Called	7	12
Restriction Warranted	5	9

Table 7.7.3-8 Number of observed violations and letters written by FNSB for Stage 1 and Stage during 2017/2018 heating season

	Stage 2	Stage 1
Observed Violations	137	105
Warning Letters	111	90

Following the removal of the Borough's authority to regulate wood stoves and other wood and coal-fired heating devices on October 2, 2018, DEC, by virtue of its regulation that was adopted

[10] http://fnsb.us/transportation/AQDocs/2018-07-16%20FNSB%20AQ%20Stakeholders.pdf

into the SIP on September 7, 2015, assumes the authority of calling air quality alerts, curtailment announcements, and conducting compliance and enforcement in the Fairbanks nonattainment area. DEC calls the alert or curtailment for the entire nonattainment area, or specific zones: North Pole Zone, Fairbanks Zone, or both depending on the available meteorological data, weather forecasts, affected area, the strength of the inversion, and potential duration of the inversion. Through outreach methods, which includes online sign-up electronic notification, local media outlets (TV, radio) and the Division's Air Quality Advisories web page at: http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-curtail-alert/, DEC notifies the public about air quality alerts, episodes, and exemptions. Exemptions from a curtailment included in an announcement may consist of areas experiencing power outages and residents who have temporary waivers. Exceptions to individual episodes may also include exceptions based on the class or type of device or based on a device's particulate emission rates.

Table 7.7.3-9 displays the number of alert restrictions called by the Alaska Department of Environmental Conservation for the 2018/2019 heating season. As shown in Table 7.7.3-10, DEC issued 27 NOASH waivers and honored 34 FNSB NOASH waivers and 244 FNSB Stage 1 waivers (which were issued on or before October 25, 2018). Unlike the Borough, the State regulation only permits DEC to issue temporary waivers. During the 2018/2019 heating season, DEC used two field staff and four post processing staff for compliance and enforcement, spent a total of 17 days for surveillance, and ended up with 184 unique addresses. A total of 38 complaints were received from the public during the curtailment alerts.

Table 7.7.3-9. Number of Stage restrictions called by DEC during 2018/2019 heating season

Number of Alert Restrictions Called	Stage 1	Stage 2
North Pole:	12	19
Fairbanks:	14	1
Total:	26	20

Table 7.7.3-10. Burn restriction waivers issued by DEC during 2018/2019 heating season

Burn Restriction Waivers Issued	
DEC NOASH Waivers:	27
FNSB NOASH Waivers (honored by DEC):	34
FNSB Stage 1 Wavers (honored by DEC):	244
Total:	305

For the 2018/2019 heating season, as displayed in Table 7.7.3-11, there were 40 observed violations for Stage 1 for which DEC sent 30 advisory/compliance letters while for Stage 2, there were 199 violations for which 167 letters were sent. Post processing of observations is conducted by DEC staff, which may result in staff finding that a letter or action is not required (such as identification of a NOASH household or an oil heater stack that was mistaken for a solid-fuel heater stack).

Table 7.7.3-11. Number of Stage violations and advisory/compliance written by DEC 2018/2019 heating season

Violations of Alert Restrictions	Stage 1	Stage 2
Observed:	40	199
Advisory/Compliance Letters Sent:	30	167

The FNSB air quality code was modified and strengthened through many ordinances. For the 2017/2018 heating season FNSB had the following regulations, in addition to the curtailment program, aimed at reducing $PM_{2.5}$ pollution:

21.28.030 (A) Installation of an unlisted appliance. Installation of Certain Solid Fuel Burning Appliances in the Nonattainment Area. Within the nonattainment area no person shall install or allow the installation of a solid fuel burning appliance unless it is listed by the borough as qualifying under this chapter and the installation complies with all other requirements imposed in this chapter. It is a separate violation to fail to remove a solid fuel burning appliance installed in violation of this chapter.

21.28.030 (B) Failure to remove, using or operating a prohibited hydronic heater. No person who has been convicted of or pled no contest to two or more violations of this chapter involving visible emissions or emissions crossing property lines shall, in the air quality control zone, operate, use or keep installed a hydronic heater unless the hydronic heater is:

1. Borough listed or was listed at the time of installation,
2. A closed combustion system with automatic components that feed solid fuel, including wood pellets, into a firebox where the combustion is enhanced by an active airflow system, or
3. Connected to a thermal mass system that is certified by the contractor or installer as sufficient to allow the hydronic heater to burn at maximum capacity minimizing on/off cycling. The division may require an owner to provide documentation supporting the certification.

21.28.030 (C) Violation of visible emissions standard. No person shall cause, permit, or allow particulate emissions from a non-mobile source in the air quality control zone to create opacity greater than 20 percent for a period or periods aggregating more than 10 minutes in any hour except during the first 40 minutes after the initial firing when the opacity limit shall be less than 50 percent.

21.28.030 (D) Emissions crossing property lines. $PM_{2.5}$ Emissions Crossing Property Lines. No person shall cause or permit particulate emissions from a non-mobile source to impact the resident(s) of a neighboring property through the creation of an emissions plume that:

1. Crosses a property line;
2. Is observable using EPA Method 22 (40 CFR 60 Appendix A); and
3. Is 25 µg/m3 greater than the surrounding immediate vicinity background $PM_{2.5}$ level using methods defined by the borough division of air quality. For purposes of this subsection, the surrounding "immediate vicinity" means land within an area measured 1,200 feet in all directions from the boundaries of the emitting property.

21.28.030 (E) Failure to obtain, submit and execute a permit for installing a SFBA in new construction. For all new construction that commences on or after January 1, 2018, and is located within the air quality control zone the following will apply:

a. Installation of a solid fuel burning appliance is prohibited unless a permit has been issued by the division. A permit must be obtained for any solid fuel burning appliance installed in new construction prior to installation of the appliance.

21.28.030 (F) Illegal installation of hydronic heaters. Unless permitted by a variance, or if replacing an existing hydronic heater with a listed appliance, no person shall install or allow the installation of a hydronic heater located less than:

a. Three hundred thirty feet from the closest property line; or
b. Six hundred sixty feet from a school, clinic, hospital, or senior housing unit.

21.28.030 (G) Use of prohibited fuels. No person shall burn in the borough any fuel, except coal in an appliance designed to use coal, which is not listed in the manufacturer's owner's manual as an acceptable fuel for that device or any of the following items in a solid fuel burning appliance:

1. Any wood that does not meet the definition of clean wood or has more than 20 percent moisture content;
2. Garbage;
3. Tires;
4. Materials containing plastic or rubber;
5. Waste petroleum products;
6. Paints and paint thinners;
7. Chemicals;
8. Glossy or colored papers;
9. Construction and demolition debris;
10. Plywood;
11. Particleboard;
12. Saltwater driftwood
13. Manure;
14. Animal carcasses;
15. Asphalt products;
16. Flooring products.

21.28.030 (H) Violation of commercial sale requirements. No person shall sell or lease an unlisted solid fuel burning appliance or barrel stove kit in the borough unless the buyer signs an affidavit, on a form prescribed by the borough, attesting that the appliance will not be installed or used in the air quality control zone. This section does not apply to appliances or stoves that transfer pursuant to a sale of property;
2. No person shall commercially sell or offer for sale or lease a solid fuel burning appliance in the borough unless the commercial seller or dealer provides the prospective buyer or lessee, prior

to any sales or lease agreement, with a written notice, prepared or approved by the division, that includes, but is not limited to, the following:

a. The fuel restrictions imposed in this chapter;
b. Proper installation, property location, operation, and maintenance of the appliance;
c. An advisory statement noting that operation of solid fuel burning appliances may not be appropriate in some areas due to terrain, meteorological conditions, or other relevant conditions that render the operation of the appliance a public nuisance or health hazard even though it is otherwise legally installed and operated.

21.28.060 Filing a false affidavit. It shall be a violation to submit a false affidavit for a "no other adequate source of heat" determination.

FNSB compliance and enforcement efforts for the 2017/2018 season recorded a total of 205 violations, a breakout is provided in Table 7.7.3-12

Table 7.7.3-12. Number of observed violations by FNSB during 2017/2018 heating season

Code Provision	Number of Violations
21.28.030 (A) Installation of an unlisted appliance	0
21.28.030 (B) Failure to remove, using or operating a prohibited hydronic heater	0
21.28.030 (C) **Violation of visible emissions standard**	**1**
21.28.030 (D) **Emissions crossing property lines**	**9**
21.28.030 (E) Failure to obtain, submit and execute a permit for installing a SFBA in new construction	0
21.28.030 (F) Illegal installation of hydronic heaters	0
21.28.030 (G) Use of prohibited fuels	0
21.28.030 (H) Violation of commercial sale requirements	0
21.28.050 (C) **Violation of Stage 1 air alert**	**90**
21.28.050 (D) **Violation of a Stage 2 air alert**	**105**
21.28.060 Filing a false affidavit	0

7.7.3.5 AHFC Energy Programs

The Alaska Housing Finance Corporation (AHFC) implements several energy programs that are designed to make homes more energy efficient.[11] Since adopting the Energy programs as a voluntary measure under the Moderate SIP, they have continued to be implemented in the Fairbanks nonattainment area. As homeowners make energy efficiency improvements, they reduce the amount of fuel and electricity needed for power and heat leading to corresponding air quality benefits due to the reduced fuels being burned for space heating and power generation.

Under the AHFC Home Energy Rebate Program, home owners may receive up to $10,000 for making energy-efficient improvements to their existing home based on before and after energy ratings made by Energy Raters. Homeowners must get an initial energy rating and apply for the program. Eighteen months is provided to complete improvements with a second energy rating after the improvements are done. Homeowners are reimbursed (up to a specified amount) for the energy ratings and receive a rebate based on their home's improved energy-efficiency and eligible receipts. Only those improvements recommended by the rater are eligible for the rebate.

There is also a Home Rebate Program that provides a $10,000 rebate for 6 Star homes and $7,000 for 5 Star Plus homes (the highest AHFC energy rating categories). In addition, AHFC offers interest rate reductions when individuals finance new or existing energy efficient home when borrowers purchase and make energy improvements to an existing home. Any property that can be energy rated and is otherwise eligible for AHFC financing may qualify for the energy efficiency interest rate reduction program.

Individuals who meet income limits are eligible to apply for the AHFC Weatherization Assistance Program. Local weatherization providers provide program services at no cost to qualified homeowners and renters including single and multifamily homes, mobile homes, apartments, and condominiums. The Weatherization Assistance Program provides low- and moderate-income households with improvements to their homes which increase the energy efficiency of their dwelling, including measures such as:

- Air sealing attics, crawlspaces, etc.
- Insulating and weather stripping
- Repair and replacement of heating systems
- Replacement of doors and windows
- Installation of fans, smoke alarms, CO detectors

7.7.3.6 Expanded Availability and Use of Natural Gas

The State of Alaska is actively working towards expanding the availability and use of natural gas in the Fairbanks nonattainment area through the implementation of the Interior Energy Project. A key to reducing fine particulate matter air pollution in the Fairbanks nonattainment area in the long term, as identified in the Moderate SIP, is expanding the availability of affordable, cleaner burning fuel options within the nonattainment area. In April 2013, the Alaska Legislature

[11] https://www.ahfc.us/about-us

unanimously passed the Senate Bill 23 which established the Interior Energy Project. The legislation authorizes the Alaska Industrial Development and Export Authority (AIDEA) to provide the financing package to partner with the private sector to build a liquefied natural gas (LNG) plant and natural gas heating distribution system in Fairbanks and the North Pole. The current projections indicate that the earliest this project will provide additional natural gas into the community is 2020.

7.7.3.7 Required Replacement of Non-Certified Wood Heating Devices When Properties are Sold

Section 172(c)(9) of the CAA requires nonattainment plans to "provide for the implementation of specific measures to be undertaken if the area fails to make reasonable further progress, or to attain the national primary ambient air quality standard by the (applicable) attainment date . . . ." As such, due to the reclassification of the Fairbanks nonattainment area to a Serious nonattainment area, effective June 9, 2017, the contingency measure in 18 AAC 50.077 requires older wood-fired heating devices to be replaced upon the sale of a property. The contingency measure also provides the ability for limited temporary waivers.

These limited waivers, which may be granted on a case by case basis, depend on the following factors:

- Financial hardship information provided by the owner or operator;
- Technical feasibility information provided by the owner or operator;
- Potential impact to locations with populations sensitive to exposure to $PM_{2.5}$ including hospitals, schools, child care facilities, health clinics, long-term care facilities, assisted living homes, and senior centers.

DEC regulations in 18 AAC 50.077 and 18 AAC 50.079 (as amended through September 2018) require solid fuel-fired heating devices including wood stoves, pellet stoves, coal stoves and hydronic heaters, to be removed from a property before sale, lease, or conveyance in the Fairbanks North Star Borough $PM_{2.5}$ nonattainment area unless they are EPA-certified (wood and pellet stoves), have a qualifying Phase 2 "White Tag" (hydronic heaters), or meet current emission standards.[12,13] The regulations apply to devices located anywhere on the property including inside the home, in a garage, and in outbuildings.

To facilitate the continued implementation of the contingency measure, DEC organizes outreach programs, which include presentation and Q&A sessions, to educate real estate professionals and vendors in the Fairbanks nonattainment area. Initial contacts began in May 2016 with 1400 letters sent to real estate professionals. A dedicated webpage at: http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-real-estate/ has been developed to provide information. As displayed in Table 7.7.3-13 below, since the triggering of the contingency measure, six outreach letters have thus far been sent to each of the real estate professionals and vendors while seven outreach presentations have been conducted. While real-

[12] 18 AAC 50.077
[13] 18 AAC 50.079

estate professionals are contacted by DEC about three times per week, solid-fuel device vendors are contacted about two times per year. DEC updates the EPA device list once per month, and thus far, there have been seven real-estate investigations for noncompliance.

Table 7.7.3-13. Contingency Measure Requiring Replacement of Older Wood Heating Devices When Properties Are Sold

Number of Outreach letters sent to real-estate professionals, vendors etc.	6
Outreach (presentations, Q&A) to real-estate professionals, vendors etc.	7
Average weekly Real-estate contacts	3
Updated ADEC Maintained EPA device list	Once per month (when applicable)
Number of real-estate investigations for noncompliance	7
Regular contact with solid fuel device vendors	Twice per year

7.7.3.8 Enhanced Dry Wood Compliance: Registration of Wood Sellers and Moisture Content Disclosure (Contingency Measure)

The registration of wood sellers and moisture content disclosure was initially implemented as a voluntary measure and then triggered as a regulatory contingency measure upon the reclassification of the Fairbanks nonattainment area to a Serious nonattainment area effective June 9, 2017. DEC regulations in 18 AAC 50.076, as amended through September 15, 2018, require that commercial wood sellers register with the State before selling or providing wood to a person located in the Fairbanks nonattainment area. Also, the provisions in the regulations require that registered wood sellers use a DEC-approved moisture test meter to test the moisture content of a load of wood at the time of sale, provision, or delivery to the consumer.

The requirements for testing the moisture content of split wood, wood rounds or logs that are cut at the time of or before the sale and that are marketed, sold or provided as dry wood are stipulated in the regulations. DEC requires that the registered wood sellers document the measured moisture content on the moisture content disclosure form that the department provides, and obtain the consumer's signature or mark unavailable if the customer is not available. The State's Moisture Disclosure Program requires wood sellers to register and provide wood moisture content information to buyers. While the publishing of information on vendors that sell dry wood is increasing the awareness of burning only dry wood in both newer and older wood-fired heating devices, the tracking of moisture content of wood sold, as well as number of the cords of wood sold, is helping to monitor the progress of the contingency measure.

Currently, as shown in Table 7.7.3-14 below, there are 18 registered wood sellers in the Fairbanks nonattainment area, among which are two dry wood sellers. To date, 2,407 forms have been received from the commercial wood sellers, and about 1593 cords of woods have been sold. On a monthly average, about 50 forms are received, and about 33 cords are sold. While larger wood sellers are visited once per month, smaller operators are visited less frequently.

Table 7.7.3-14. Registered Wood Sellers Statistics

Number of registered wood sellers (Fairbanks Nonattainment Area)	18 (2 recognized dry wood sellers)
Number of forms received to date	2407
Number of cords tracked to date	~ 1593
Average number of forms received per month	~ 50
Average number of tracked cords sold per month	~ 33
Frequency of site visits for moisture checks conducted	Approximately once a month for larger sellers and less frequently for smaller operators

7.7.3.9 Expanded Availability of Plug-Ins

Preheating vehicles, also called pugging-in, provides a substantial reduction in motor vehicle cold start emissions. As such, this transportation control strategy was made a voluntary measure and included in the Moderate SIP.

Public education is an important part of this control strategy. The Borough encourages residents to plug in their vehicles at temperatures up to 20° above zero. Engine block heaters are considered an essential component of winter driving in Fairbanks. It is estimated that a significant number of vehicles will not start at temperatures of 20° F below zero. Since –20° F or colder temperatures are a frequent occurrence in winter, it was assumed that by encouraging motor vehicle operators to plug in at warmer temperatures, carbon monoxide and $PM_{2.5}$ emissions would be reduced without creating an onerous burden on residents, as they already have engine block heaters. Subsequent test programs conducted by DEC and the Borough confirmed the emission benefits of plugging-in at warmer temperatures. Television spots were produced to inform the public of the multiple benefits of plugging in at warmer temperatures. Although not scientific in nature, the messages were that plugging in:

1. Reduces engine wear, thus reducing vehicle maintenance costs;
2. Improves air quality;
3. Improves chances of complying with the federal Clean Air Act; and
4. Improves vehicle starting and reduces the idling time needed before driving.

Based on its historical success in implementing the plug-in program, the Borough continues public awareness as part of it implementation of an ordinance that requires owners of parking lots to provide power to electrical outlets for plug-ins at temperatures below 20° F. In the past, four elementary schools within the $PM_{2.5}$ nonattainment area had been equipped with 193 plug-ins while 9,727 spaces of government and private areas within the Fairbank CO nonattainment area had been upgraded with 9,033 plug-ins. Also, as of 2013, two high schools within the

Fairbanks $PM_{2.5}$ nonattainment had been equipped with a total of 542 plug-ins using the Federal Highway Administration (FHWA) CMAQ funds. Table 7.7.3-15 below displays the most recent update (as of April 12, 2019 from FAST-Act) on the plug-in projects in the Fairbanks nonattainment area between 2015 and 2019.

Table 7.7.3-15. Additional Parking Lots Equipped with New Plug-ins from 2015-2019

Fairbanks Nonattainment Area Additional Parking Lots Equipped with New Plug-ins 2015-2019 (as of April 12, 2019)		
Facility	**New Plug-ins**	**Comments**
Carlson Center	600	To be completed on August 31, 2019
Big Dipper Ice Arena	300	To be completed on August 31, 2019
North Pole Library	25	Project completed
Fairbanks Library	50	Project completed
Total	975	

7.7.3.10 Mass Transit System

The Borough began operating the Metropolitan Area Commuter System (MACS) fixed route transit service in 1977. The MACS system is comprised of nine fixed routes in the cities of Fairbanks and North Pole, as well as other nearby communities. The MACS service operates Monday through Friday from 6:00 AM to 9:45 PM and limited routes on Saturday from 8:45 AM to 7:45 PM. There is no Sunday service.

The Borough also operates a door-to-door paratransit service, Van Tran, which began in 1988. The American Disabilities Act of 1990 (ADA) requires all public transit systems that provide fixed route bus and rail service to also provide an alternative transportation service (usually vans and small buses) for people with disabilities who cannot use fixed route bus and train service. This service is usually called "paratransit." The Van Tran service operates up to five nine-passenger vans and gives priority to ADA-certified disabled passengers within a ¾-mile zone around all MACS fixed routes, although they will travel beyond the ¾-mile buffer on occasion.

The vanpool system was updated in 2014 with a new approach to make it a successful operation. Other notable improvements include better bus stop facilities (bus stop signs and shelters) and a bus tracking system for the public. The FNSB intends to build eight more shelters in 2020. The Borough also conducts active public outreach and education to encourage the use of mass transit. Table 7.7.3-16 below displays the number of MACS riders from 2008-2018.

Table 7.7.3-16. Transit program ridership levels from 2008-2019

Table 7.7-6 Annual MACS Transit Ridership 2008 – 2019	
Year	MACS Number of Riders

2008	294,142
2009	357,964
2010	383,773
2011	391,799
2012	428,166
2013	475,875
2014	550,226
2015	533,045
2016	534,705
2017	528,000
2018	523,000*

*The anticipated ridership for 2018/2019 will not be final until July 1, 2019. The slight decrease in ridership compared to 2017/2018 is due to a reduction in some service time on 2 of the Borough's mass transit bus routes.

7.7.3.11 DOT Anti-Idling and Diesel Emission Reductions

Anti-idling (idle reduction) technologies provide a means to reduce air pollution from transportation sources. Emissions from vehicles are directly related to the amount of fuel used and the rate at which it is used. By reducing the need to have the vehicle engine on, emission reductions are achieved. Hence, the transportation control strategy, which has since been discontinued, was implemented as one of Moderate SIP voluntary control measures in the Fairbanks nonattainment area.

In July 2011, the Alaska Department of Transportation & Public Facilities (DOT&PF) began to focus on anti-idling and its potential benefits statewide. According to the DOT&PF, reducing idling saves money, conserves fuel, reduces engine wear and maintenance, extends the life of heavy equipment, and helps to preserve the environment. Consequently, the Alaska Department of Environmental Conservation coordinated with DOT&PF to develop a Fairbanks specific CMAQ-funded pilot program aimed at reducing heavy diesel emissions in the nonattainment area. This program was implemented by DEC Air Quality staff in Fairbanks.

Table 7.7.3-17 below displays the number of participating fleets and the number of vehicles equipped with idle reduction through 2017

Table 7.7.3-17. Expansion of Diesel Anti-idling Program

Number of participating fleets	3
Number of vehicles equipped with idle reduction technology	39

7.7.3.12 DEC Diesel Emission Reduction Efforts

Diesel emission reduction efforts were one of the voluntary transportation control strategies identified in the Moderate SIP. When the efforts started in 2009, DEC, in conjunction with DOT&PF, used the American Recovery and Reinvestment Act of 2009 (ARRA) and Diesel

Emission Reduction Act of 2005 (DERA) funding to upgrade the engine of three 1985 Autocar KM64 trucks to meet the 2010 clean diesel requirements. Also in 2013, ADEC and DOT&PF retrofitted 23 diesel vehicles with anti-idling technology using DERA grant funding through 2016. DEC has since discontinued implementing the diesel emission reduction efforts under DERA, which are now being implement by the Alaska Energy Authority.

7.7.3.13 Federal Diesel Emission Reduction Programs

The diesel emission reduction programs are still being implemented by the federal government to address diesel emissions in nonattainment areas, including Fairbanks nonattainment area. EPA's National Clean Diesel Campaign works with manufacturers, fleet operators, air quality professionals, environmental and community organizations, and state and local officials to reduce diesel emissions. The National Clean Diesel Campaign offers Diesel Emission Reduction Act funding opportunities through the competitive National Clean Diesel Funding Assistance Program to fund retrofit projects using Smartway verified diesel emission reduction technologies and the non-competitive State Clean Diesel Grant Program that funds grant and loan projects for clean diesel projects. Smartway is a public-private initiative between EPA, large and small trucking companies, rail carriers, logistics companies, commercial manufacturers, retailers, and other federal and state agencies. Its purpose is to improve fuel efficiency and the environmental performance (reduction of both greenhouse gas emissions and air pollution) of the goods movement supply chains. Smartway evaluates emissions control technologies and determines the eligibility of individual technologies for funding under DERA grants. Federal emissions standards for exhaust and evaporative emissions exist for Light-Duty Vehicles, Trucks, and Motorcycles, Heavy-Duty Engines and Vehicles, and Non-road Engines and Vehicles. These emissions standards on manufacturers have incrementally reduced the amount of emissions permitted from each type of regulated engine, resulting in cleaner diesel engines.

7.7.3.14 Federal Motor Vehicle Control Program

The Federal Motor Vehicle Control Program (FMVCP) is the federal certification program that requires all new cars sold in 49 states (excluding California) to meet certain emission standards. The standards required by the ongoing FMVCP vary according to vehicle age. Newer vehicles are required to be considerably cleaner than older models. The more stringent emission standards required from newly manufactured vehicles have, over time, led to a drop in overall emissions from the vehicle fleet in Fairbanks nonattainment area, as older, dirtier vehicles are replaced with newer, cleaner vehicles.

While the Tier 2 emission standards, which were phased-in from 2004-2009, were meant to reduce emissions responsible for ozone and particulate from passenger cars, light trucks and larger passenger vehicles, the Tier 3 emission standards, which were phased-in 2017, are meant to further enhance the performance of motor vehicle emission control systems. The Tier 3 emission standards have continued to reduce both tailpipe and evaporative emissions from passenger cars, light-duty trucks, medium-duty passenger vehicles, and some heavy-duty vehicles.

7.7.3.15 Winter Season Open Burning Ban

DEC, through its existing regulations, 18 AAC 50.245 and 18 AAC 50.065, makes sure that smoke emissions from open burning do not increase in the Fairbanks nonattainment area even if the authority of the Borough to regulate open burning is removed through voter initiative. To facilitate the continued implementation of the Moderate SIP control measure, 18 AAC 50.065(f) prohibits open burning during the winter season between November 1 and March 31.[14] Although DEC contemplated a longer season (including October and April) for open burning restrictions in the nonattainment area, after receiving public comments in 2014 the then available data suggested that there is no significant air quality deterioration from normal open burning during these months. DEC also revised the definition of open burning in 2014 to address the concerns raised by the public regarding small winter fires for recreational warming and ceremonial purposes.

7.7.3.16 Reasonably Achievable Control Technology

The CAA section 172 (c) requirements for nonattainment areas apply to the $PM_{2.5}$ nonattainment area. Under this attainment plan, the requirements of CAA Part D, New Source Review (NSR) apply for major stationary sources. Section 302 of the CAA (42 U.S. C. 7602) defines a major stationary source as any stationary facility or source of air pollutants that directly emits, or has the potential to emit, 100 tons per year of any pollutant. Permits for construction and operation of new or modified major stationary sources within the nonattainment area must be approved through the NSR program. Within the FNSB, ADEC is responsible for issuing construction and Title V operating permits. DEC has incorporated the requirements for Prevention of Significant Deterioration (PSD) and nonattainment New Source Review in 18 AAC 50, Article 3. DEC actively implements its permit programs. The Air Quality Division issues and amends permits, conducts inspections, reviews reports from industry, provides compliance assistance, and takes enforcement actions when needed.

Under the Moderate SIP, each stationary source in the Fairbanks nonattainment area was the subject of a Reasonably Achievable Control Technology (RACT) analysis. The emission units for which RACT determinations were made include boilers, process heaters, and turbines. The $PM_{2.5}$ RACT is a fabric filter system for boilers. Additional $PM_{2.5}$ controls are considered unreasonable for process heaters and turbines. RACT for the SO_2 emissions is the use of low sulfur fuel for all the fuel combustion sources. RACT controls were not recommended for NO_X because control of NO_X is not an efficient method for reducing ambient $PM_{2.5}$ in Fairbanks.

All the emission units that were reviewed are already implementing the emission control techniques identified as RACT. All the coal-fired units are already equipped with fabric filters, and Alaskan coal has a very low sulfur content.

[14] 18 AAC 50.065

Best Available Control Measures Analysis for Fairbanks $PM_{2.5}$ Nonattainment Area

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April 19, 2019

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1. Introduction

In November 2009, Fairbanks North Star Borough was designated as a Moderate nonattainment area for the 2006 24-hour Fine Particulate ($PM_{2.5}$) National Ambient Air Quality Standard (NAAQS).[1] On April 28, 2017, EPA officially re-classified the Fairbanks from "Moderate" to "Serious" nonattainment for the 24-Hour $PM_{2.5}$ standard.[2] The design value for the 2013-2015 period is 124 $\mu g/m^3$(microgram per cubic meter). The difference between this value and the ambient standard is 89 $\mu g/m^3$, which means that 98th percentile concentrations (the form of the standard) need to be reduced by 72% to demonstrate attainment.

The purpose of this document is to describe the process of identification and selection of Best Available Control Measures (BACM) for the $PM_{2.5}$ Attainment Plan for the Fairbanks North Star Borough (FNSB, or Fairbanks) in Alaska.

Presented below is a review of the regulatory requirements that need to be addressed in the review, analysis and selection of BACM. Also presented is a summary of revisions made to strengthen both FNSB and ADEC $PM_{2.5}$ regulatory controls, independent of the BACM selection process. This summary is relevant as it documents revisions made since the adoption of the Moderate Fairbanks $PM_{2.5}$ SIP which was approved by EPA on September 8, 2017.[3] Those revisions form the baseline set of controls against which control measures adopted in other communities and agencies are examined for BACM selection. A brief outline of the remainder of the report is also presented.

Requirements for BACM Analysis

The process for selecting BACM is defined in a series of steps detailed in the Final $PM_{2.5}$ Rule.[4] Those steps clarify and update PM_{10} control measure selection guidance presented in the Addendum to the General Preamble[5] for the selection of $PM_{2.5}$ controls for both Reasonably Available Control Measures (RACM), required for Moderate nonattainment areas and BACM for Serious nonattainment areas. Presented below is a summary of the BACM selection guidance presented in the Final $PM_{2.5}$ Rule.

- **Step 1: Develop a Comprehensive Inventory of Sources and Source Categories of Directly Emitted $PM_{2.5}$ and $PM_{2.5}$ Precursors** – The inventory identifies the contribution of each source category to directly emitted $PM_{2.5}$ and precursor emissions. This information is needed to understand the relative contribution and significance of

[1] https://www.gpo.gov/fdsys/pkg/FR-2009-11-13/pdf/E9-25711.pdf
[2] https://www.federalregister.gov/documents/2017/05/10/2017-09391/determinations-of-attainment-by-the-attainment-date-determinations-of-failure-to-attain-by-the
[3] https://www.federalregister.gov/documents/2017/09/08/2017-18768/air-plan-approval-ak-fairbanks-north-star-borough-2006-pm25
[4] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf
[5] https://www3.epa.gov/ttn/naaqs/aqmguide/collection/cp2/19940816_59fr_41998-42017_addendum_general_preamble.pdf

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each source to the overall burden on the nonattainment area. EPA requires the identification of both anthropogenic (man-made) and non-anthropogenic (natural) emissions. It also requires the analysis to start with the base year emissions inventory submitted with the Moderate area attainment plan and to update it as necessary to reflect growth, construction, shutdowns, roadway improvements and other relevant changes that affect activity within the nonattainment area. EPA also requires the Step 1 inventory to be consistent with the emissions inventory requirements for Serious area plans.

- **Step 2: Identify Potential Control Measures** – Consistent with earlier guidance, the $PM_{2.5}$ Final Rule requires states to identify controls for each of the primary and secondary emission sources developed to represent activity within the subject nonattainment area. The starting point for assembling a list of controls is the RACM analysis prepared for the Moderate SIP. All controls considered, but not adopted must be identified. States are required to examine a wide range of information sources on existing and potential control measures. Measures and technologies considered and implemented in attainment plans are a significant source of information. Other information sources include summaries of control measures assembled by regional planning organizations and local air quality consortiums. EPA also maintains online links to a variety of control programs. States are required to identify both existing and potential new measures for the source categories identified in the base emissions inventory. The goal is to identify a list of control measures that are more stringent than those adopted in the Moderate SIP.

- **Step 3: Determine Whether an Available Control Measure or Technology is Technologically Feasible** – This requires the consideration of many factors including impacts on the environment (e.g., air, water, noise, etc.) and energy (e.g., consumption, availability, etc.). Measures targeting area and mobile sources need to consider infrastructure, population size, workforce type and habits, etc. In addition the critical source parameters needed to assess the impacts of the technology need to be identified (e.g., fuel specifications, travel activity, EPA certification, etc.). A key consideration is whether the identified measure provides an emissions benefit beyond those provided by existing federal, state and local controls (i.e., is it more stringent?). Another consideration is the availability of information to contrast and quantify the emission impacts of an identified measure relative to existing control programs (i.e., again, is it more stringent).

- **Step 4: Determine Whether an Available Control Technology or Measure is Economically Feasible** – This step requires an explicit examination of the costs and emission benefits of the measure leading to an assessment of the $/ton of pollutant reduced. In contrast to the criteria employed in the RACM determination process, economic feasibility "is a less significant factor." States "may not eliminate a particular control measure as potential BACM if similar sources have successfully implemented such a measure." States are also required to consider technologically feasible measures that have not been implemented by similar sources, but can reduce emissions at a cost that is not prohibitive. The Final $PM_{2.5}$ Rule does not establish a specific $/ton threshold for economic feasibility. More expensive control measures must be adopted unless it can be demonstrated that costs and cost effectiveness are prohibitive relative to existing controls.

- **Step 5: Determine the Earliest Date by Which a Control Measure or Technology can be Implemented in Whole or in Part** – The CAA requires Serious area attainment plans to provide for the implementation of BACM no later than 4 years after reclassification of the area to Serious or prior to the statutory attainment date for the area. If a state determines that technologically and economically feasible measures can be implemented in whole or in part during this period they must be adopted and implemented as expeditiously as possible. Since Fairbanks was classified nonattainment for $PM_{2.5}$ in December, 2009 the statutory attainment date is December, 2019.

Revisions to Strengthen $PM_{2.5}$ Regulatory Controls

Recognizing the need to make continued progress towards attainment both the Borough and the state continued to evaluate and adopt regulatory controls after the submission of the Moderate area SIP. Since these controls form the baseline against which BACM technical and economic feasibility is to be assessed, a summary of the measures adopted is presented below.

Borough Ordinance Revisions

The $PM_{2.5}$ Air Quality Control Program is codified in Chapter 21.28. Numerous changes to the program were debated within the Assembly leading to the adoption of ten separate Ordinances amending the program since the submission of the Moderate Area Plan to EPA December 31, 2014 and January 29, 2015. Collectively, those changes significantly increased the coverage and authority of the program to control emissions within the nonattainment area. Passage of Proposition 4, the Home Heating Reclamation Act, on October 5, 2018, however, required the Borough to remove all of the ordinances implementing home heating restrictions, calling air quality alerts and enforcing them. In the absence of a local control program, the Clean Air Act requires states to take responsibility for implementing air quality control programs that move the community towards attainment of the NAAQS.

Alaska Administrate Code Revisions

Amendments were adopted in 2016 and 2017 to reflect locally-adopted control measures.

With an effective date of November 26, 2016, the SIP was adopted by reference. In addition, the following sections of Chapter 50, the Air Quality Code were amended:

- Section 50.025: Visibility and other special protection areas to establish three "air quality control zones" within the Fairbanks $PM_{2.5}$ Nonattainment Area: Goldstream, Fairbanks, and North Pole;
- Section 50.030: State air quality plan to adopt revisions to the State Air Quality Control Plan in Volume II SectionIII.D.5: Fairbanks North Star Borough PM-2.5 Control Plan;
- Section 50.075: Wood-fired heating device visible emission standards to lower visible emission standards for solid fuel-fired heating devices during air quality advisories and to

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allow the Department discretion to prohibit operation of solid fuel-fire heating devices during air quality episodes;
- Section 50.076: Solid fuel-fired heating device fuel requirements to add the list of materials that cannot be burned in a solid fuel-fired heating device,
- Section 50.077: Standards for wood-fired heating devices to prohibit the reinstallation of wood-fired hydronic heaters and wood stoves that do not meet emission standards within a nonattainment area.

With an effective date of January 2, 2018, the following Sections of Chapter 50 of the Air Quality Code were amended:

- Section 50.030: State air quality plan to adopt revisions to the Control Plan and add language addressing nonattainment area permit requirements;
- Section 50.075: Wood-fired heating device visible emission standards to add new language on visible emissions standards and to remove language that is no longer applicable;
- Section 50.077: Standards for wood-fired heating devices to address requirements for wood-fired heating devices, heating device test methods and address heating devices located in the FNSB nonattainment area;
- Section 50.079: (New) to address requirements for coal-fired heating devices;
- Section 50.990: to add definitions

The following amendments to Chapter 50 of the Air Quality Code are currently under administrative review and will become effective when implemented:

- Repeal and replace Section 50.077 and include a new subsection 50.077(k)(1) that requires wood-fired heating devices to be registered with DEC
  - Upon sale of a new device by vendor or dealer,
    a. Vendor shall also provide curtailment information to the buyer at the time of sale
    b. Review of proper operating instructions with buyer
  - Prior to issuance of any waivers
  - In order to participate in the Burn Right Program
  - In order to participate in any wood-stove change-out or conversion program
- Add a new section 50.078(b): Requires only Diesel #1 may be sold for home heating fuel – starting July 1, 2020
- Add a new Section 50.076(d): Effective October 1, 2021, commercial wood sellers must ensure that wood being sold must have a moisture content less than 20%. Registered commercial and wood sellers will continue with existing regulations until September 30, 2021. After October 2021, only dry wood can be sold that is either
  - Properly seasoned, split and stored and covered for at least 9 months
  - Mechanically dried, where the drying process has been inspected and approved by the department to ensure consistency and reliability or
  - Harvested from an inspected fire killed source that has been split, stacked and confirmed dry prior to freezing.
- Includes an affidavit to the buyer that the wood is dry, on forms provided by the department.

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- Add a new Section 50.078(e): Non-commercial wood sellers may only sell dry wood
- Repeal and replace Section 50.077(b): Requires all EPA uncertified devices and all outdoor hydronic heaters, except outdoor pellet fueled hydronic heaters to be
  - Removed or replaced by December 31, 2024
  - Removed or replaced before being sold, leased or conveyed as part of an existing building; and
  - All removed devices must be destroyed or rendered inoperable.
- Repeal and replace Section 50.077(c): No outdoor hydronic heaters may be sold or installed unless pellet fueled.
- Repeal and replace Section 50.077(d): Identifies EPA emission rate used as a requirement of pellet fueled wood fired hydronic heater, that EPA certification is required, EPA test methods and measurements are used (0.10 mmBTU/hr)
- Repeal and replace Section 50.077(e): Identifies EPA emission rate used as a requirement of catalyst equipped and pellet fueled wood stoves, that EPA certification is required, and EPA test methods and measurement requirements are used (2.0 g/hr)
- Repeal and replace Section 50.077(f): Identifies EPA emission rate used as requirement of non-catalyst woodstoves, that EPA certification is required, EPA test methods and measurement requirements are used and a TEOM emission profile approved by the Department before allowed on DEC list of approved devices (2.0 g/hr)
- Repeal and replace Section 50.077(g): Identifies EPA emission rate used for wood-fired heating devices meeting a rated size of 350,000 btu or greater per hour, that EPA certification is required, and EPA test methods and measurement requirements are used (2.0 g.hr)
- Repeal and replace Section 50.077(h): Allows department to review manufacturer test results and place a model on the list of devices the department prepares identifying what devices are allowable under this section.
- Repeal and replace Section 50.077(i): Allows sale of a device not meeting regulations to be sold outside of the nonattainment area when confirmed in writing by the buyer the device will not be installed within the nonattainment area.
- Repeal and replace Section 50.077(j): Allows for a temporary waiver for conveyance of an existing noncompliant device after department considers financial hardship, technical feasibility and potential impact to locations sensitive to exposure to $PM_{2.5}$.
- Add a new subsection 50.077(k)(2) & (3): Wood-fired heating devices and wood-fired retrofit control devices must be professionally sized and professionally installed with confirmation of proper installation and location. Installers must be certified. Replacement devices must be confirmed removed and destroyed.
- Add a new subsection 50.077(k)(4): Wood-fired heating devices may not be the primary or only heating source:
  - New construction, except “dry cabins” on a 2-acre parcel
  - For rental units, unless a rental unit prior to the effective date of the regulations and qualifies for a NOASH
- Add a new subsection 50.077(k)(5): Wood-fired heating devices not meeting regulations may not be advertised for sale within the area.
- Add a new Section 50.079(f): Existing coal-fired heating devices to be:
  - Removed or replaced by December 31, 2024

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  - Removed or replaced before being sold, leased or conveyed as part of an existing building
  - Removed devices shall be destroyed or rendered inoperable
- Add a new subsection 50.075(e)(3): Fuel to non-exempt devices must be withheld and combustion in these devices – as evidenced by visible smoke from a chimney – must cease within three hours after announcement of a curtailment of operation under an emergency episode.
- Add a new subsection 50.075(f)(2): Solid fuel fired heating device shall be operated so that visible emissions do not cross property lines.
- Add an Episode Chapter[6] addressing Advisory and Alert thresholds:
  - Advisory - 15µg/m^3
  - Stage 1 – 20 µg/m^3
  - Stage 2 – 30 µg/m^3
- Add an Episode Chapter addressing NOASH and Exemption requirements:
  - Length of waivers based on age and emission rate of the device
  - Annual renewals on oldest and highest emission rated devices
  - 3rd party inspection of device to verify proper installation required
  - 3rd party inspection of maintenance (chimney sweep) required
  - Device registration required
  - Documentation of dry wood required
- Add a new subsection 50.078(c): One time submission of information requirement for small area sources: charbroilers, incinerators and waste oil burners
- Add a new subsection 50.078(d): Requires that coffee roasters within the area install a pollution control device appropriate to the unit approved by the department, unless the facility provided information demonstrating control technology is technically or economically infeasible. The requirement for installation of control equipment on coffee roasters will be 1 year from the effective date of regulation

In addition to the code revisions noted above, the Serious designation triggered the implementation of contingency measures contained in the Moderate $PM_{2.5}$ SIP. Alaska's regulations contain two contingency measures for the Fairbanks $PM_{2.5}$ nonattainment area. The first addressed property transactions and went into effect immediately. It requires removal or replacement of older, more polluting, solid fuel-fired devices when a property is sold, leased, or conveyed which will accelerate turnover and result in fewer of these devices operating in the area and reduce wood smoke emissions. Solid fuel-fired devices that appear on any of DEC's lists of EPA-certified and Phase 2 "White Tag" devices do not need to be removed or replaced. The second requires commercial wood sellers to register with the state and disclose the moisture content of wood they sell; it went into effect after a 60-day public notice period. This information aids consumers to make educated decisions about whether wood needs to be seasoned to reduce its moisture content to less than 20%, or if the wood is dry and can be burned right away.

[6] Vol. II: III.D.7.12, Fairbanks Emergency Episode Plan, hereafter referred to as the Episode Chapter

Outline for Remainder of the Section

The remainder of this document is organized to present the findings of analyses addressing each of the 5 BACM steps outlined above. Section 2 presents a summary of the calculations prepared to quantify the baseline emission inventory (Step 1). A summary of the process followed to identify potential control measures is presented in Section 3 (Step 2). Section 4 presents the results of the technological feasibility analysis prepared for each of the measures identified in Section 3 (Step 3). Section 5 presents the results of the economic feasibility analysis for each measure determined in Step 3 to be technologically feasible (Step 4). Section 6 presents information on the earliest date at which measures determined to be technologically feasible (and/or adopted in a new state regulation) in Step 3 and economically feasible in Step 4 can be implemented (Step 5). Section 7 presents a summary of the selected BACM measures. Appendix A contains a reference to the state's analysis of the costs of transitioning to lower sulfur heating oil.

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2. Step 1 – Develop a Comprehensive Inventory of Sources and Source Categories of Directly Emitted and $PM_{2.5}$ and $PM_{2.5}$ Precursors

The first element in the multi-step BACM process consists of the development of an emission inventory (EI) of sources of directly-emitted $PM_{2.5}$ and $PM_{2.5}$ precursors within the nonattainment area. This section describes that process. It includes a list of all source categories reflected in the inventory and a summary of the sources and activities in the nonattainment area. It also includes a summary of emissions by source category of both directly emitted $PM_{2.5}$ and its precursors.

Source Categories Inventoried

Overview - The inventory supporting the BACM analysis was developed in a manner consistent with the EI requirements for Serious area plans specified in EPA's $PM_{2.5}$ Implementation Rule[7] (or PM Rule). This included representation of source activity and emissions on a seasonal, rather than annual basis as provided for under the PM Rule. As discussed in the separate Emission Inventory document, use of seasonal estimates is appropriate for the 24-hour $PM_{2.5}$ standard in Fairbanks since violations of the standard are confined to winter months (October through March) and source activity that triggers these violations peaks during that time.

The inventory was developed using the 2008 base year emission inventory for the Fairbanks $PM_{2.5}$ nonattainment area from the approved Moderate SIP as its starting point and then updated based on additional source and activity data collected since preparation of that inventory. The inventory was projected forward to calendar year 2019 and reflects growth, and controls in place at the end of 2018.

This inventory covers activity and emissions across the following source types:

1. *Stationary Point Sources* – Industrial facility emissions for major stationary sources based on the major source reporting threshold of 70 tons/year as required for Serious plan inventories under the PM Rule;

2. *Stationary Nonpoint (or Area) Sources* – Includes all remaining stationary sources, including both industrial facilities below the major source reporting threshold above as well as "traditionally" defined area sources such as residential and commercial space heating and other disperse stationary emission sources;

3. *On-Road Mobile Sources* – Represents activity and emissions from on-road motor vehicles which includes gasoline and diesel-powered passenger cars, light-duty trucks/vans, buses and heavy-duty trucks; and

[7] Federal Register, Vol. 81, No. 164, August 24, 2016 (FR 81 58010).

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4. *Non-Road Mobile Sources* – Emissions from all remaining mobile sources than are not on-road certified vehicles. This includes non-road vehicles/equipment such as construction/mining equipment, off-highway vehicles, snowmobiles and other recreational vehicles, aircraft and airfield equipment and locomotives.

Figure 1 shows the boundaries of the Fairbanks $PM_{2.5}$ nonattainment area (shaded region) overlaid on the roadway system in the area. The nonattainment area covers 271 square miles. Figure 1 also shows the names and locations of the six major point sources located within the nonattainment area (using blue dots).

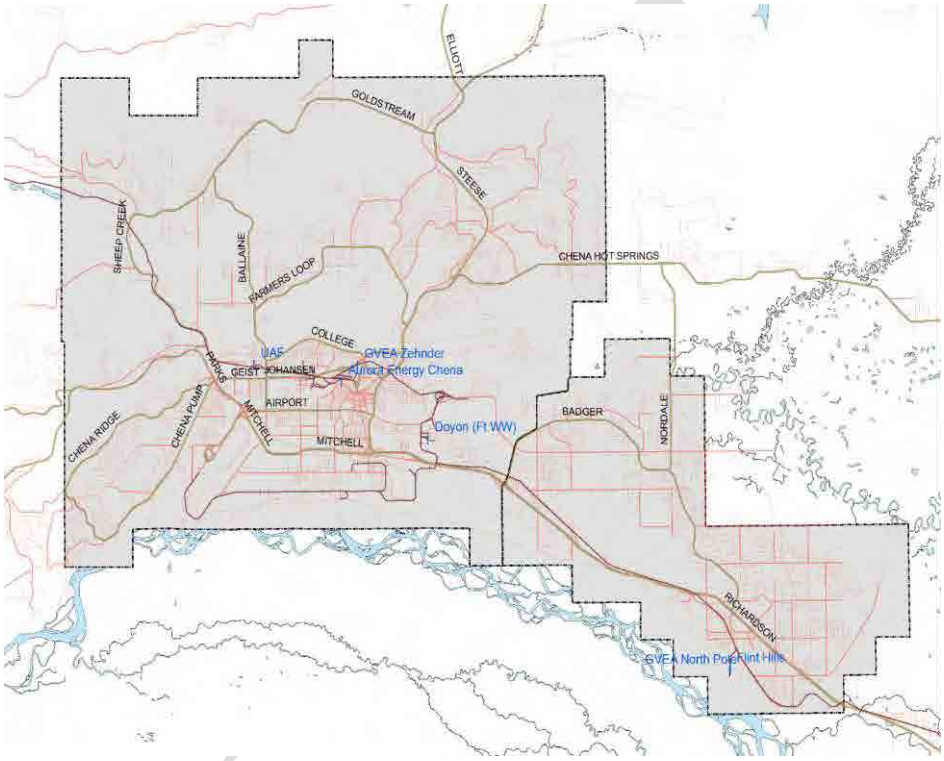


Figure 1. Fairbanks $PM_{2.5}$ Nonattainment Area

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Sources Included and Pollutants Covered – The inventory included a review of all anthropogenic and biogenic emission sources within the nonattainment area. As described in greater detail in the Emission Inventory document, it was determined that biogenic emissions were negligible during the winter season represented in the inventory. In addition, fugitive dust sources of $PM_{2.5}$ were also estimated to be negligible under the snow/ice bound conditions reflected in the winter seasonal inventory.

Pollutants represented in the inventory consisted of both direct $PM_{2.5}$ as well as emissions of potential precursor pollutants: sulfur dioxide (SO_2), oxides of nitrogen (NOx), volatile organic compounds (VOC), and ammonia (NH_3).

Summary of Inventory Data Sources and Methods – Table 1 briefly summarizes the data sources and methods used to develop the emissions inventory by source type. It also highlights those elements based on locally-collected data. As shown by the shaded regions in Table 1, the majority of wintertime activity and emission factor data supporting the inventory was developed based on local data and test measurements.

Table 1. Summary of Data/Methods Used in Serious SIP Inventory

Source Type/Category	Source Activity	Emission Factors
Point Sources	Facility and stack-level fuel use and process throughput	Continuous emissions monitoring or facility/fuel-specific factors
Area (Nonpoint) Sources, Space Heating	Detailed wintertime Fairbanks non-attainment area residential heating device activity measurements and surveys	- Test measurements of common Fairbanks wood and oil heating devices using local fuels - AP-42 factors for local devices or fuels not tested (natural gas, coal)
Area Sources, All Others	- Seasonal, source category-specific activity from a combination of State/Borough sources - National Emission Inventory (NEI)-based activity for commercial cooking	AP-42 emission factors
On-Road Mobile Sources	Local estimates of seasonal vehicle miles traveled	- MOVES2014b emission factors based on local fleet/fuel characteristics - Augmented with Fairbanks wintertime vehicle warmup and plug-in emission testing data
Non-Road Mobile Sources	- Local activity estimates for key categories such as snowmobiles, aircraft and rail - MOVES2014b model-based activity for Fairbanks for other categories	- MOVES2014b model factors for non-road equipment - AEDT model factors for aircraft - EPA factors for locomotives

For all inventory sectors, emissions were calculated using a "bottom-up" approach that relied heavily on an exhaustive set of locally measured data used to support the emission estimates. For source types for which local data were not available, estimates relied on EPA-developed NEI

county-level activity data and emission factors from EPA's *Compilation of Air Pollutant Emission Factors*,[8] AP-42 database.

Within the inventory, activity and emissions were represented at the individual Source Classification Code (SCC) level, with the exception of the major point sources. Major point source emissions were compiled by SCC, facility and emission unit.

Updating Moderate SIP Estimates – The Moderate SIP contained a 2008 base year inventory. This inventory was updated to the 2013 baseline year of the Serious Plan based on a combination of activity projections (for example population/housing growth) from 2008 to 2013 and new or revised activity estimates and emission factors/models which are summarized below for the key elements. These values were projected to 2019 and reflect changes due to growth, and controls in place at the end of 2018.

- *Point Sources* – 2008 activity and emissions data were projected to 2013 and 2019 based on annual fuel use/process throughput by individual facility and emission unit. Fuel-based ammonia emissions for point sources were also included in the 2019 inventory.

- *Space Heating Area Sources* – Additional home heating survey data collected in winters 2012 through 2015 were used to augment the estimates of residential space heating device/fuel mix and usage in the Moderate SIP based on the singular 2011 Home Heating survey. This broader sample of survey data was combined to more robustly reflect residential space heating activity within the nonattainment area for calendar year 2013 (which is centered in the combined 2011-2015 home heating survey period) and projected forward to 2019. Additional survey data were also collected from commercial businesses in the nonattainment area to estimate the extent of space heating from solid fuel burning devices (wood or coal) in commercial buildings. (The Moderate SIP assumed all commercial space heating used only liquid (heating oil) or gaseous (natural gas) fuels).

- *Mobile Sources* – For both on-road and non-road vehicles, EPA's latest vehicle emissions model, MOVES2014b was used to replace emission estimates from the Moderate SIP based on its predecessor, MOVES2010a.[9] On-road vehicle activity (VMT and speeds) was based on 2019 travel demand model outputs from the Fairbanks Metropolitan Area Transportation System (FMATS) 2040 Metropolitan Transportation Plan (MTP). (The Moderate SIP used travel model estimates for 2008 from a prior transportation plan.) For non-road vehicles/equipment MOVES2014b was used to calculate 2019 calendar year emissions. The Federal Aviation Administration's AEDT model was used to estimate aircraft/airfield emissions in 2019 based on activity data collected for that year. (The Moderate SIP used the predecessor model to AEDT, EDMS, based on 2008 activity).

[8] "Compilation of Air Pollutant Emission Factors," Fifth Edition and Supplements, AP-42, U.S. EPA, Research Triangle Park, NC. January 1995.

[9] MOVES2014b models both on-road and non-road vehicles/equipment. MOVES2010a only modeled emissions from on-road vehicles; a separate model NONROAD2008 was used in the Moderate SIP to address non-road vehicle emissions.

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Summary of Emissions

Emissions for the 2013 baseline inventory within the Fairbanks $PM_{2.5}$ nonattainment area were updated from the 2008 Moderate SIP base year inventory as summarized in the preceding section. They were tabulated by key source sector and updated to reflect the effects of growth through 2019 and controls in place at the end of 2018. Table 2 presents the resulting Control emission inventory estimates, expressed as average day emissions within the winter season for 2019. Emissions of direct $PM_{2.5}$ are highlighted in the first column. Precursor pollutant emissions are also shown. As seen in Table 2, the largest share of direct $PM_{2.5}$ comes from space heating, with wood-burning being the dominant fuel type. For NOx and SO_2, point sources are the dominant contributor. (The majority of VOC and NH_3 precursors emissions also come from space heating).

Table 2. 2019 Control Emissions Inventory (tons/day) by Source Sector

Source Sector	Nonattainment Area Winter Season Emissions (tons/day)				
	$PM_{2.5}$	**NOx**	**SO_2**	**VOC**	**NH_3**
Point	0.83	10.63	7.13	0.09	0.020
Area, Space Heating, All	2.09	2.43	3.85	8.70	0.132
Area, Space Heat, Wood	1.94	0.39	0.14	8.48	0.086
Area, Space Heat, Oil	0.07	1.82	3.60	0.10	0.003
Area, Space Heat, Coal	0.08	0.05	0.09	0.11	0.014
Area, Space Heat, Other	0.01	0.17	0.02	0.01	0.029
Area, Other	0.20	0.25	0.02	2.35	0.049
On-Road Mobile	0.14	2.14	0.04	3.25	0.048
Non-Road Mobile	0.28	1.25	11.33	0.68	0.000
TOTALS	**3.55**	**16.70**	**22.36**	**15.06**	**0.248**

To provide a clearer understanding of the significance of each source sector, Table 3 provides a breakdown of the percentage contributions of each sector (or subcategory) to total emissions for each pollutant. As shown in Table 3 over 58% of direct $PM_{2.5}$ comes from space heating. Point sources contribute just under 24% of direct $PM_{2.5}$, with other area sources and mobile sources accounting for the remaining 18%. For NOx, point sources are the major contributor, accounting for roughly 64% of total emissions. Space heating is the second largest NOx source, representing 15%. SO_2 emissions come primarily from non-road mobile point sources (51%), with point sources contributing the next largest share (32%).

Since the portion of emission sources encompassing all categories except point sources are subject to BACM (point sources are addressed under BACT), these tabulations show that space heating is the dominant, but not singular source of emissions under BACM.

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Table 3. 2019 Control Emissions Inventory
Contributions by Source Sector (% of total pollutant emissions)

Source Sector	Nonattainment Area Winter Season Emissions (tons/day)				
	$PM_{2.5}$	NOx	SO_2	VOC	NH_3
Point	23.5%	63.7%	31.9%	0.6%	7.9%
Area, Space Heating, All	58.9%	14.6%	17.2%	57.8%	53.0%
Area, Space Heat, Wood	54.6%	2.4%	0.6%	56.3%	34.5%
Area, Space Heat, Oil	1.8%	10.9%	16.1%	0.7%	1.4%
Area, Space Heat, Coal	2.1%	0.3%	0.4%	0.7%	5.5%
Area, Space Heat, Other	0.4%	1.0%	0.1%	0.1%	11.6%
Area, Other	5.8%	1.5%	0.1%	15.6%	19.6%
On-Road Mobile	3.9%	12.8%	0.2%	21.6%	19.4%
Non-Road Mobile	7.9%	7.5%	50.7%	4.5%	0.0%
TOTALS	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

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3. Step 2 – Identify Potential Control Measures

The second step in the BACM identification and evaluation process is to identify candidate control measures. In this step, a list of control measures potentially applicable to the mobile and area source $PM_{2.5}$ source categories is developed for consideration as BACM. States are required to examine a wide range of information sources on existing and potential control measures in the search for candidate BACM. The Final $PM_{2.5}$ Rule requires the list of potential controls to include "options not previously considered as RACM/RACT", control measures being implemented in other nonattainment areas, and measures considered by regional planning organizations and state and local air quality consortiums. The goal is to identify a list of control measures that are more stringent than those adopted in the Moderate Area SIP. Presented below is a summary of agencies and measures considered, and the measures selected for consideration as BACM. RACT-related sources and control technologies are addressed in the Moderate SIP.

RACM

As noted earlier, the starting point for assembling a list of controls is the RACM analysis prepared for the Moderate Area SIP. All controls that were considered, but not adopted, must be identified. Table 4 lists the measures the RACM analysis determined to be technologically infeasible (Table 5.7-6. Candidate Control Measures Considered for RACM) and economically infeasible (Table 5.7-7. Technologically Feasible Control Measures). Many of the measures determined to be technologically infeasible were rejected because of a referendum that was in place prohibiting the Borough from regulating home heating systems and fuels. The referendum has since lapsed; however, a replacement initiative was passed initiative was passed by local voters in the 2018 fall election. Several measures were rejected because they were determined to be not practically enforceable in the Borough. The Final $PM_{2.5}$ Rule eliminated this criterion as a basis for infeasibility. Two of the measures were determined to be economically infeasible. The first provided economic incentives to switch to lower sulfur fuel oil. The second addressed expansion of the District heating system. Both measures are considered here as candidate measures for BACM.

The RACM analysis noted that "Five of the technologically feasible and cost effective control measures have not already been implemented." They included:

- Hydronic heaters: voluntary curtailment on air quality advisory days
- Hydronic heaters: All new units must be certified to 2.5 gm/hr
- Wood stoves: All new units must be certified to 2.5 gm/hr
- Open burning: Reinstate open burning ban
- Burn barrels: Prohibit use of burn barrels (seasonal or year-round)

The RACM analysis stated that all "of these measures may be implemented within four years of designation, with a target implementation date of 1st Qtr 2016." While those measures were all implemented in early 2016, the Borough regulations were removed following voter approval of

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the Home Heating Reclamation Act in 2018 and these programs are now being regulated solely by ADEC. All of these measures are addressed in the BACM analysis.

Table 4 lists source categories, the titles of control measure and the disposition/Measure # of each. The title of the control measure includes a sequence number identifying its place in the RACM analysis. The disposition/Measure # column lists each of the sequence numbers assigned to measures evaluated in the BACM analyses. Those starting with the letter R indicate that it is RACM measure. The measure sequence numbers not preceded by the letter R (e.g., Ban on green wood sales is listed as 36) indicate the candidate BACM measures identified in the review of regulations adopted by other jurisdictions that address the same source category. Some of the RACM measures deemed infeasible are addressed in multiple control strategies identified in the regulations of other jurisdictions and include multiple measure sequence numbers (e.g., Mandatory curtailment on Air Quality Advisory Days is addressed in Measures 19, 22 and 35). Measure "19. Use stove change outs to generate NSR offsets" is addressed as a candidate BACT measure in the BACT report. Each of the other measures listed in Table 4 is analyzed for technical feasibility in Step 3.

Table 4. Fairbanks RACM Controls Found to be Technologically Infeasible

Source Category	Control Measure	Measure #
Dry Wood	1. Regional kiln	R1
	2. Ban on green wood sales	36
Hydronic Heaters	3. Mandatory curtailment on Air Quality Advisory Days	19, 22, 35
	4. All units must be certified	R4
	5. Ban new installations	R5
	6. Remove at time of home sale	R6
	7. Ban use	R7
Wood Stoves	8. Mandatory curtailment on Air Quality Advisory days	19, 22, 35
	9. All units must be certified	R9
	10. Replace uncertified units at time of sale	R10
	11. Replace uncertified units at time of significant remodeling	R11
	12. Replace uncertified stoves in rental units	R12
	13. Require alternate heat source in rental units	24
	14. Require alternate heat source in new construction	8
	15. Ban new installations	R15
	16. Disincentives to sell used stoves	R16
	17. Ban use	R17
	18. Use stove change outs to generate NSR offsets	BACT Measure
Fireplace	19. Mandatory curtailment on Air Quality Advisory days	19, 22, 35
Transportation*	20. HOV lanes	R20

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Table 4. Fairbanks RACM Controls Found to be Technologically Infeasible

Source Category	Control Measure	Measure #
	21. Traffic flow improvement program	R20
	22. Create non-motorized traffic zones	R20
	23. Employer-sponsored flexible work schedules	R20
	24. Retrofit diesel fleet (school buses, transit fleets)	R20
	25. On-road vehicle I/M program	R20
	26. Heavy-duty vehicle I/M program	R20
	27. State LEV program	R20
Fairbanks RACM Controls Found to be Economically Infeasible		
Residential Fuel Oil Combustion	28. Provide economic incentives to switch to low sulfur fuel	51
	29. Increase Coverage of District Heating Systems	R29

* All listed transportation measures are addressed as a single measure – R20.

Control Measures Implemented in Other Nonattainment Areas

A wide range of rules implementing SIP controls were examined to identify control measures for consideration as BACM. Table 5 lists the local jurisdictions and states whose regulations were examined to identify potential $PM_{2.5}$ control measures. It also lists the links to 33 separate websites containing rules and regulations adopted by these jurisdictions to control $PM_{2.5}$ emissions. Several states and local jurisdictions have multiple rules addressing $PM_{2.5}$ control. Most rules are extensive and contain separate sections addressing definitions, prohibitions, stage restrictions, exemptions, penalties, etc. Use of these links facilitated the comparative evaluation of control program requirements in the Fairbanks North Star Borough and State of Alaska to those of other jurisdictions to determine if those of other jurisdictions are potentially more stringent than corresponding Fairbanks' requirements - the screening qualification for consideration as BACM.

After reviewing the range of $PM_{2.5}$ control programs in place across the country, it became apparent that many had similar structures, and detailed requirements reflecting local decisions about how best to implement needed controls. Since the programs reviewed did not fit into a uniform template, evaluations of them had to be conducted in a careful manner to understand requirement nuances. Definitions differ, prohibitions and thresholds for implementation differ, exemptions frequently differ, etc. Thus, while it was tempting to contrast entire regulatory packages to determine which provided the largest reduction in emissions, quantification of reductions was found to be a complex exercise because of the numerous regulatory differences between these packages and that of Fairbanks. Several of the findings made during this initial approach were that:

1. Considerable effort would be required to develop separate spreadsheets for each regulatory package to quantify overall emission benefits in Fairbanks;

2. Individual components of regulatory packages that could provide benefits in Fairbanks could be missed if other components of the same packages offset these benefits when packages were considered in toto (i.e., throwing the baby out with the bathwater);
3. Comparisons of individual regulatory elements is easier to analyze and present for review;
4. Comparisons of individual regulatory elements do not require spreadsheet analysis to determine which elements are more stringent;
5. Frequently, the data or estimates needed to contrast measures quantitatively do not exist: impacts on emissions due to differences in exemption details, approved device categories, installation requirements, curtailment requirements, enforcement policies, shifts in behavior, etc.

Collectively, the issues listed above led to a decision to contrast elements of regulatory packages with those of the Borough and the State of Alaska. The search for regulatory elements that appeared to be more stringent than those in Fairbanks and Alaska regulations first produced a list of jurisdictions implementing them and weblinks to the applicable regulations. This list is presented in Table 5.

Table 5. Programs Examined to Identify Candidate $PM_{2.5}$ Control Measures

Location/Information Sources
Arvada, CO – https://yosemite.epa.gov/r8/r8sips.nsf/e5e850cc767bc8b3872573a9004cad73/bd3b257587d4a7de87257e0c00703faf/$FILE/ATTBMOIH.pdf/(c)(1)%205%20CCR%201001-6,%20Reg%204.8.1.%20Arvada%20Ord%202451.pdf
Georgia, GA – https://epd.georgia.gov/air/sites/epd.georgia.gov.air/files/related_files/document/narrative_08.16.12%20atlanta.pdf
Alaska, AK – http://dec.alaska.gov/commish/regulations/pdfs/18-AAC-50.pdf
Aurora, CO – https://library.municode.com/co/aurora/codes/building_and_zoning?nodeId=BUZOCO_CH146ZO_ART12SURESPUSAC_DIV1GEUS_S146-1204BURE
Idaho, ID – https://www.deq.idaho.gov/media/930589-cache_valley_pm2_5_nonattainment_state_implementation_plan_1212.pdf – https://adminrules.idaho.gov/rules/2014/58/0101.pdf – http://www.deq.idaho.gov/media/930593-cache-valley-pm2-5-sip-appendices-1212.pdf
Colorado, CO – https://yosemite.epa.gov/R8/R8Sips.nsf/PrintSips/C5D17E5CB9461F8587257EED004BBD82?OpenDocument – https://www.colorado.gov/pacific/cdphe/aqcc-regs – https://www.colorado.gov/pacific/sites/default/files/5-CCR-1001-6_1.pdf
Delaware, DE – http://regulations.delaware.gov/AdminCode/title7/1000/1100/1113.shtml
Fairbanks North Star Borough, AK – http://www.codepublishing.com/AK/FairbanksNorthStarBorough/#!/FNSBC21/FNSBC2128.html#21.28

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Table 5. Programs Examined to Identify Candidate $PM_{2.5}$ Control Measures

Location/Information Sources
Feather River AQMD, CA – https://www.arb.ca.gov/drdb/fr/cur.htm
Imperial County, CA – https://www.arb.ca.gov/drdb/imp/cur.htm
Kern County, CA – https://www.arb.ca.gov/drdb/ker/cur.htm
Klamath County, OR – http://www.co.klamath.or.us/EH/Air%20Quality%20&%20Burning/Klamath%20County%20Clean%20Air%20Ordinance.htm
Lincoln County, MT – http://lincolncountymt.us/images/departments/environmental_health/pdf/air_quality/AirOrdinanceRev_10MAY2017.pdf
Maine, ME – https://www.maine.gov/sos/cec/rules/06/096/096c150.doc
Maricopa County, AZ – http://www.maricopa.gov/DocumentCenter/View/5332 – http://www.maricopa.gov/DocumentCenter/View/5252 – http://www.maricopa.gov/DocumentCenter/View/5200
Missoula City-County, MT – https://www.missoulacounty.us/home/showdocument?id=8452
New York State, NY – https://govt.westlaw.com/nycrr/Browse/Home/NewYork/NewYorkCodesRulesandRegulations?guid=I591033205f9311e0b70f0000845b8d3e&originationContext=documenttoc&transitionType=Default&contextData=(sc.Default) – http://www.dec.ny.gov/chemical/51986.html
Ada County, ID – http://www.sterlingcodifiers.com/codebook/index.php?book_id=447
Lane Regional APA, OR – http://www.lrapa.org/DocumentCenter/View/253 – https://www.lanecounty.org/UserFiles/Servers/Server_3585797/File/Government/County%20Departments/County%20Counsel/Lane%20Code/LC09.pdf
Pennsylvania, PA – https://www.pacode.com/secure/data/025/chapter123/s123.14.html
Utah, UT – https://rules.utah.gov/publicat/code/r307/r307-302.htm
Puget Sound CAA, WA – http://www.pscleanair.org/219/PSCAA-Regulations
Bay Area AQMD, CA – https://www.arb.ca.gov/DRDB/BA/CURHTML/R6-3.PDF
San Juaquin Valley APCD, CA – https://www.valleyair.org/rules/currntrules/r4901.pdf
South Coast AQMD, CA – https://www.arb.ca.gov/DRDB/SC/CURHTML/R445.PDF – https://www.arb.ca.gov/DRDB/SC/CURHTML/R444.PDF
Vermont, VT – http://dec.vermont.gov/sites/dec/files/aqc/laws-regs/documents/Statutes07-01-2014.pdf#zoom=100
Washington, WA

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Table 5. Programs Examined to Identify Candidate $PM_{2.5}$ Control Measures

Location/Information Sources
– http://apps.leg.wa.gov/WAC/default.aspx?cite=173-400

The next step was to isolate the specific elements in these rules and regulatory packages that appeared to be more stringent than the corresponding elements in FNSB and Alaska regulations. These elements were assigned short descriptive titles and then organized into groups of common functionality. In other words, all of the specific elements that regulated device installation were grouped together under the group title of "Device Installation – General". Element groups were then organized in a sequence that followed the chronological events in device acquisition, use, and retirement, such as sale, installation, permitting, exemption granting, operation, curtailment during air quality advisories, and removal. Because the analysis of source categories contributing to $PM_{2.5}$ nonattainment in the Borough identified coal burning, heating oil combustion, and motor vehicle travel as being significant, elements of regulations implemented by other jurisdictions that addressed these sources were grouped together in separate categories. The list of these functionality groups and individual regulatory elements evaluated is presented in Table 6. Listed with each regulatory element are the jurisdictions implementing these elements.

Table 6. Control Measures Implemented in $PM_{2.5}$ Nonattainment Areas That Have Not Been Implemented in FNSB

Measure Description	Areas Implementing Measure
Sale of Devices - New	
1. Surcharge on Device Sales	Washington, WA
Sale of Devices – Used	
2. Prohibit advertising used devices that do not meet emission criteria for new device sales	Ada County ID Utah, UT Colorado, CO
Device Installation – General	
3. Require building or other permit	Missoula City-County MT Ada County ID Klamath County OR
4. Require confirmation of proper installation by requiring professional installation or on-site inspection	San Joaquin Valley APCD CA
5. Register/require industry certification of heating professionals	San Joaquin Valley APCD CA
6. Prohibit installation of flue dampers unless device was certified using a flue damper	Missoula City-County MT
7. Require devices meet stricter emission criteria in high pollution zones.	Missoula City-County MT
8. Prohibit installation of Solid Fuel Heating Device (SFHD) in new construction	South Coast AQMD CA San Joaquin Valley APCD CA Bay Area AQMD CA

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Table 6. Control Measures Implemented in $PM_{2.5}$ Nonattainment Areas That Have Not Been Implemented in FNSB

Measure Description	Areas Implementing Measure
9. Limit the density of SFHD in new developments	San Joaquin Valley APCD CA East Kern AQMD CA
10. Install EPA-certified device whenever a fireplace or chimney is remodeled	Bay Area AQMD CA
Device Installation - Hydronic Heaters	
11. Prohibit use of rain caps on stacks	Maine, ME
12. Require minimum stack height relative to rooflines of nearby unserved buildings	Maine, ME New York, NY Utah, UT
13. Submit sale and installation information to Air Program	New York, NY
14. Require installation of thermal mass to improve efficiency and prevent frequent cycling in selected new units	U.S. Environmental Protection Agency
Device Removal	
15. Disclosure of devices on property sale	Lane Regional APA OR San Joaquin Valley APCD CA
16. Require notice and proof of destruction or surrender of removed, uncertified devices	Puget Sound CAA WA
17. Require Removal of Uncertified Solid Fuel Burning Devices Upon Sale of Property	Puget Sound CAA WA
Device Operation – Opacity	
18. No Visible Emissions during Curtailment Periods	Puget Sound CAA WA Maricopa County AZ
Device Operation – Permits	
19. Require registration of devices to qualify for exemption from curtailments	Missoula City-County MT San Joaquin Valley APCD CA
20. Require renewals with inspection requirements	San Joaquin Valley APCD CA
21. Optional device registration for curtailment exemptions	San Joaquin Valley APCD CA Maricopa County AZ
22. Require registration of all devices	Missoula City-County MT
23. Require exempt households to display a decal visible from a point of public access	Ada County ID
Device Operation – NOASH	
24. Require Permanent Installed Alternative Heating Method in Rental Units	Bay Area AQMD CA Klamath County OR Aurora CO
25. Require detailed application or inspection to verify need	Puget Sound CAA WA
26. Require inspection of device and installation	San Joaquin Valley APCD CA
27. Require annual renewal of waiver	Maricopa County AZ
28. Set income threshold	Missoula City-County MT Maricopa County AZ

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Table 6. Control Measures Implemented in $PM_{2.5}$ Nonattainment Areas That Have Not Been Implemented in FNSB

Measure Description	Areas Implementing Measure
29. Allow only NOASH households to burn during curtailment periods	Utah, UT
Fuels	
30. Distribution of Curtailment Information at Time of Sale of Wood-Burning Device	South Coast Air Quality AQMD CA, Bay Area AQMD CA
31. Require sale of only dry wood during late summer to end of winter	South Coast AQMD CA
32. Require dry wood to be clearly labeled to prohibit marketing of non-dry wood as dry wood	San Joaquin Valley APCD CA Bay Area AQMD CA
Open Burning	
33. Burn permits required	Klamath County OR Feather River AQMD CA
34. Prohibit burn barrels and other outdoor equipment	Klamath County OR
35. Restrict burning during air pollution events	Ada County ID Klamath County OR
36. Prohibit residential open burning	South Coast AQMD CA
37. Periodic burn windows	Klamath County OR
Curtailment Programs – Averaging Period	
38. Ambient PM2.5 concentration (1-hr average)	Idaho, ID
Curtailment Programs – Thresholds	
39. Use of AQI as Basis for Curtailment Threshold	Idaho, ID
Curtailment Programs – Stages	
40. Single stage ban	Ada County ID Idaho, ID Maricopa County AZ Utah, UT Lane Regional APA OR Feather River AQMD CA Arvada CO Aurora CO
Curtailment Program – Exemptions	
41. Special needs permit	Missoula City-County MT
42. Burn down period	Puget Sound CAA WA Maricopa County AZ
43. Exempt ceremonial or religious fires	South Coast AQMD CA
44. Alternative heating appliance failure	Missoula City-County MT Maricopa County AZ Klamath County OR
45. Elevation-based	South Coast AQMD CA
46. Lack of electrical or natural gas service availability	Utah, UT South Coast AQMD CA

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Table 6. Control Measures Implemented in $PM_{2.5}$ Nonattainment Areas That Have Not Been Implemented in FNSB

Measure Description	Areas Implementing Measure
	San Joaquin Valley APCD CA
Curtailment Program – Inspections	
47. Inspection warrants	Aurora CO
Coal	
48. Date certain removal of "coal only heater"	Puget Sound CAA WA
49. Prohibit use of coal burning heaters	Longmont CO
50. Require low sulfur content coal	Missoula City-County MT Puget Sound CAA WA
51. Ultra-low Sulfur Heating Oil	Missoula City-County MT New York, NY Pennsylvania, PA
Used Oil	
52. Operation and sale of small "pot burners" prohibited	Vermont, VT
53. No Sale or Exchange of Used Oil for Fuel, unless it Meets Constituent Property Limits	Vermont, VT
Transportation	
54. Adopt CARB vehicle standards	Pennsylvania, PA Klamath County OR
55. School bus retrofits	Klamath County OR
56. Road paving	Nogales AZ Pinal County AZ Klamath County OR
57. Transportation Control Measures (TCMs)	South Coast AQMD CA
58. Controls on road sanding and salting	Utah, UT
59. I/M Program	Pennsylvania, PA

EPA provided comments[10]on the draft BACM document in May, 2018 and identified several additional control measures to be addressed in this analysis. In addition, analysis of commercial controls in process at the time of the release of the draft were completed and are included in this analysis. Also, several control measures were identified for consideration during the preparation of this report. Those measures are listed below in Table 7 along with the source of the measure being considered, with the exception of state incinerator controls, none of these measures are included in existing control programs.

[10] Attachment to a letter from Dan Brown to Denise Koch, 5/23/2018, EPA comments on ADEC Preliminary Draft Serious SIP Development materials for the Fairbanks serious PM2.5 nonattainment area.

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Table 7. Additional Control Measures Identified in EPA Comments and Related Literature Reviews

Measure Description	Source
60. Vehicle Idling	EPA Comment
61. Fuel Oil Boiler Upgrade – Burner Upgrade/Repair	EPA Comment
62. Fuel Oil Boiler Upgrade – Replacement	EPA Comment
63. Require Electrostatic Precipitators	FNSB
64. Weatherization and Energy Efficiency	EPA Comment
65. Emissions Crossing Property Lines	FNSB
66. Lower Curtailment Threshold	EPA Comment
67. Coffee Roasters	Commercial
68. Charbroilers	Commercial
69. Incinerators	Commercial
70. Used Oil Burners	FNSB

All of the above controls are focused on the reduction of particulate emissions. As noted in the Modeling Chapter of the $PM_{2.5}$ Serious SIP neither VOC nor NOx are significant precursor pollutants in the Fairbanks $PM_{2.5}$ nonattainment area. There is no need to identify control measures for these precursor pollutants. With regard to ammonia, EPA commented that "Unless NH_3 is demonstrated to be insignificant for this area, the serious area plan will need to include an evaluation of NH_3 and potential controls for all source categories including point sources." While a precursor demonstration of NH_3 insignificance is not feasible, a literature search for non-point source ammonia controls found no controls for Fairbanks emission sources. Controls addressing agriculture and animal waste ammonia, the predominant sources in lower-48 communities, are well documented, but those sources do not exist in Fairbanks. Therefore, no ammonia controls have been included in the BACM analysis.

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4. Step 3 – Determine Whether an Available Control Measure or Technology is Technologically Feasible

The third step in the BACM Identification and evaluation process is the analysis of the technological feasibility of each of the candidate measures identified in Step 2. As noted above, it requires the consideration of many factors including impacts on the environment (e.g., air, water, noise, etc.) and energy (e.g., consumption, availability, etc.). Measures targeting area and mobile sources need to consider infrastructure, population size, workforce type and habits, etc. In addition, the critical source parameters needed to assess the impacts of the technology need to be identified (e.g., fuel specifications, travel activity, EPA certification, etc.). A key consideration is whether the identified measure provides an emissions benefit beyond those provided by existing federal, state and local controls (i.e., is it more stringent).

As discussed in Step 2 the approach employed in selecting measures for analysis focused on differences between elements of individual rules implemented in $PM_{2.5}$ nonattainment areas and those currently implemented by the Borough and the State for the Fairbanks $PM_{2.5}$ nonattainment area. This section provides the results of detailed comparisons between the selected candidate measures and existing State regulations to determine if the candidate measures are more stringent and can provide emission reductions beyond those of currently implemented measures. As noted in Step 2 there is overlap between infeasible RACM and Step 2 candidate measures, therefore the number of measures analyzed is less than the total of 99 listed measures (29 RACM & 70 candidate measures identified in other SIPs and programs).

One category of common measures is transportation, which includes 11 separate measures (RACM #'s 20 – 27 candidate #'s 54, 57 and 59); all are analyzed as a single measure R20 (consistent with the approach employed in the RACM technological feasibility analysis). Seven other RACM measures (#'s R2, R3, R8, R13, R14, R19 and R28) are addressed in the analysis of control measures identified in other SIPs. Measure R19, is analyzed as a measure in the BACT report. Adjusting the total of 99 listed measures for the 10 reduced TCMs, 7 controls addressed in other SIPs and 1 measure evaluated as a BACT measures leaves 81 measures for analysis.

The presentation of analysis findings follows a generic format with the following components:

- Measure #, Title
- Implementing Jurisdiction
- Regulation Weblink(s)
- Background
- Analysis
- Conclusion

This format is designed to provide transparency in the information used to prepare the analysis. The weblink(s) allow easy access to the referenced rules discussed in the background and analysis presentations.

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Numerous comments were received on measures evaluated in the Draft BACM report. Where appropriate, a summary of those comments is presented in the background discussion of the measures addressed below and the analysis has been modified to address them. Because comments/suggestions/new controls have continued to become available since the preparation of the draft BACM report, an agreement was reached with EPA that no new measures would be considered in this report that became available after the September, 2018 Clean Air Conference in Fairbanks. Thus, measures recommended by Stakeholders, etc. since that time are not addressed in this report. Instead, they are addressed in the Control Strategies Chapter of the $PM_{2.5}$ Serious SIP.

Measure 1: Surcharge on Device Sales

Applicable Jurisdiction(s)

- Washington State

Regulation Weblink(s)

- https://dor.wa.gov/find-taxes-rates/other-taxes/solid-fuel-burning-device-tax

Background

A Washington State regulation imposes a fee upon the sale of solid fuel wood burning devices within the state. This regulation was adopted in or prior to 1987.[11] The fee, originally established at $15/unit, is currently set at $30/unit.[12]

This regulation requires that revenues from the program be used solely for the purposes of public education and enforcement of the solid fuel burning device program," with revenue distributed as follows:

a) 34% of the funds shall be distributed to the Woodsmoke Education Program, run by the state air agency, the Washington Department of Ecology, for the purposes of enforcement and educating the public about the effects of solid fuel heating devices on air quality and methods for achieving better efficiency from solid fuel burning devices; and
b) The remaining 66% of the funds are made available to local air authorities with enforcement programs under the Woodsmoke Enforcement Program on the basis of population.

[11] Washington Laws, 1990, available at http://leg.wa.gov/CodeReviser/documents/sessionlaw/1990c128.pdf?cite=1990%20c%20128%20%C2%A7%206; Accessed 10/10/2017.
[12] Washington State Department of Revenue, available at https://dor.wa.gov/find-taxes-rates/other-taxes/solid-fuel-burning-device-tax; Accessed 10/10/2017.

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If a local air authority is not in place, does not implement an enforcement program, or elects not to receive the funds, the funds that would otherwise be distributed under this subsection are transferred to the Department of Ecology. Businesses selling new wood stoves are also required to distribute and explain educational materials.

The biennial 2015-2017 budget for the Washington Department of Ecology estimated an income of $547,000 from the combined Woodsmoke Education and Enforcement Program, with $38,000 being allocated to the Department of Ecology for administration of affected programs and $509,000 allocated to the Air Quality Program. Of this $509,000, 34% (or roughly $173,000) was used to fund the statewide Woodsmoke Education Program. $274,000 of the remaining 66% (or $336,000) was disbursed to local agencies to fund both woodstove education and enforcement grants.[13] (Not all of the available funds are requests.)

EPA commented that implementing a surcharge "may be a helpful way to supplement limited funds. Implementation efforts within the nonattainment area could benefit from $24,000 of additional funding whether used for a code enforcer or other support of the wood smoke programs."

Analysis

Discussions with Washington Department of Ecology staff[14] found that surveys they conducted were not able to clearly estimate emission benefits from state-level education/outreach, nor were they able to provide quantitative estimates of their emission benefits based on how funds were pooled and used by local agencies. Similar findings were confirmed based on communication with the Puget Sound Clean Air Agency, one of the local air authorities that receives funding from the Department of Ecology. They too combine funds received from the Wood Stove Education and Enforcement program with revenues from other sources and use the funding for education and enforcement related to burn restrictions, but they could not easily quantify the benefits of the specific funded programs. In addition, the revenues received from this program by the local agencies are small relative to the funds received from other sources.[15]

Given the co-mingling of monies from device sale surcharges with other funding sources, both Washington State and its local air agencies cannot easily estimate emission benefits attributed to either education or enforcement-related programs.

Another consideration is that DEC has no authority to collect the funds obtained through surcharges. Funds collected from surcharges in Alaska go straight into the state's general fund,

[13] State of Washington Department of Ecology, Budget & Program Overview 2015-2017, available at https://fortress.wa.gov/ecy/publications/documents/1501007.pdf; accessed 10/12/2017.
[14] Personal communication with Stuart Clark, Washington Department of Ecology, 10/12/2017. Personal communication with Matthew Vandrush, Washington Department of Ecology, 10/12/2016.
[15] Personal communication with Amy Warren, Puget Sound Clean Air Agency, October 13, 2017.

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they are not allocated to DEC unless the legislature appropriates those funds to the agency. The implementation of this measure would require the annual allocation of the collected funds to DEC for use in enforcement and/or education. The uncertainty of this allocation does not support a SIP commitment. The only way that could occur would be through a Constitutional Amendment. Multiple years would be required to obtain such authority.

Conclusion

The timing required to adopt this measure precludes its consideration as BACM, therefore it should be addressed in a subsequent SIP as a MSM.

Measure 2: Prohibit Advertising Used Devices that Do Not Meet Emission Criteria for New Device Sales

Implementing Jurisdiction(s)

- State of Colorado

Regulation Weblink(s)

- https://www.colorado.gov/pacific/sites/default/files/5-CCR-1001-6_1.pdf

Background

Section II of Regulation 4 Limitation on the Sale and Installation of Wood-Burning Stoves states:

> *On and after January 1, 1993 no person shall sell or install a used wood-burning device within those portions of the counties of Adams, Arapahoe, Boulder, Broomfield, Denver, Douglas, and Jefferson which are located in the AIR program area, as such area is defined in Section 42-4-304(20)(a) (2006), C.R.S., unless it meets the requirements set forth in Section II.A.*

Section II.A states:

> *No person shall advertise to sell, offer to sell, sell, or install a new wood-burning stove in Colorado unless it has been tested, certified, and labeled for emission performance in accordance with applicable criteria and procedures specified in 40 CFR Part 60 … Section 60.532(a) (2015) and Section (b) or (c) (2015) (emphasis added).*
>
> - *40 CFR Part 60, Section 60.532(a) (2015) - 4.5 g/hr (0.010 lb/hr)*
> - *40 CFR Part 60, Section 60.532(b) or (c) (2015) - 2.0 g/hr (0.0044 lb/hr) using crib wood and 2.5 g/hr (0.0055 lb/hr) using cord wood, both effective in 2020.*

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Alaska recently implemented regulations that require wood-fired heating devices including wood stoves, pellet stoves, and hydronic heaters, to be removed from a property before sale, lease, or conveyance in the Fairbanks North Star Borough $PM_{2.5}$ Nonattainment Area unless they are EPA-certified (wood and pellet stoves), have a qualifying Phase 2 "White Tag" (hydronic heaters), or meet current emission standards. Those regulations, however, do not directly address the advertising restriction imposed by Colorado.

The Borough's air quality code prohibited the installation of unlisted solid fuel burning appliances. The voluntary removal, replacement and repair program required applicants to remove and deliver the appliance to an authorized decommission station and deliver a certificate of destruction to the Borough. Borough regulations also prohibited the use of unlisted solid fuel burning appliances during State 1 Alerts. All of these regulations were removed following voter approval of the Home Heating Reclamation Act.

EPA commented that Stage 1 Alerts were referred to multiple times and asked that the analysis clarify whether the measure applied during all stages of the Alert and the level of control with each stage. As noted above the referenced Borough stage restrictions no longer apply.

Analysis

To address Colorado's advertising restriction, a new regulation 18 AAC 50.077(k)(5) has been implemented. It bans advertising of wood-fired heating devices not meeting regulations within the nonattainment area and is independent of stage restrictions (addressing EPA's comments).

Conclusion

The adoption of the referenced state regulation is sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 3: Require Building or Other Permit

Implementing Jurisdiction(s)

- Missoula City-County, Ada County, Klamath County

Regulation Weblink(s)

- https://www.missoulacounty.us/home/showdocument?id=8452
- http://www.sterlingcodifiers.com/codebook/index.php?book_id=447
- http://www.co.klamath.or.us/EH/Air%20Quality%20&%20Burning/Klamath%20County%20Clean%20Air%20Ordinance.htm

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Background

Missoula City-County MT requires Installation Permits for the installation of solid fuel burning devices (SFBD) and allows Installation Permits only for pellet stoves in the Air Stagnation Zone (Section 9.203.1.a).

Ada County ID requires a solid fuel heating appliance permit for the installation of a SFBD in any new or existing building (Section 5-10-10.A). Solid fuel heating appliance permit are authorized only for clean burning appliance, which are defined as appliances certified under either the Oregon DEQ or U.S. EPA regulations and placed on the list of approved appliances by Ada County Development Services (Sections 5-10-4 and 5 10 11.A).

Klamath County OR requires a permit from the County Building Division for the installation of a solid fuel-fired appliance (Section 406.100.3.a.iii). Only appliances certified by the Oregon DEQ or U.S. EPA, and appliances that are designated exempt from Oregon DEQ or U.S. EPA regulations, are allowed to be installed with a Building Division permit (Sections 406.005.10, 406.005.12, 406.100.3.a.i, and 406.100.3.a.ii).

While the Borough had regulations governing installation permits, they were removed with the passage of the Home Heating Reclamation Act. The state had no regulations addressing installation permits.

Analysis

The Missoula City-County, Ada County, and Klamath County regulations require permits for the installation of SFBAs in any structure. Recognizing the need for equivalent regulations, the state has implemented a new regulation 15 AAC 50.077(k)(4), referenced in the introduction, that restricts approved wood-fired heating devices from being either the primary or only source of heat in new construction, except for "dry cabins" on 2+ acre parcels or rental units unless they qualify for a NOASH.

Conclusion

The adoption of the referenced state regulation is sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 4: Require Confirmation of Proper Installation by Requiring Professional Installation or On-Site Inspection

Implementing Jurisdiction(s)

- San Joaquin Valley APCD

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Regulation Weblink(s)

- http://www.valleyair.org/rules/currntrules/r4901.pdf

Background

San Joaquin Valley APCD requires that applications for wood burning device registration contain certifications by District Registered Wood Burning Heater Professionals verifying that the wood burning heaters meet device eligibility requirements (Sections 4901.5.7.3.1.2).

Fairbanks had a regulation which required installations of solid fuel burning appliances in new construction and replacement appliances in subsidized change-outs be performed by Borough-listed vendor/installers using Borough-listed appliances. Those regulations, however, were removed with the passage of the Home Heating Reclamation Act and the state had no regulations addressing professional installation confirmation or on-site inspection.

Analysis

The San Joaquin Valley measure requires that devices applying for registration be inspected by District-registered professional to confirm that the devices are District-listed as low emission units. Recognizing the need for professional installation of wood-fired heating devices and wood-fired retrofit control devices and confirmation of those installations, the state has implemented new regulation subsections 15 AAC 50.077(k)(2)&(3). As noted in the introduction, these subsections directly address those requirements. Confirmation of the removal of existing devices and their destruction is also required.

Conclusion

The adoption of the referenced state regulation is sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 5: Register/Require Industry Certification of Heating Professionals

Implementing Jurisdiction(s)

- San Joaquin Valley APCD

Regulation Weblink(s)

- http://www.valleyair.org/rules/currntrules/r4901.pdf

Background

San Joaquin Valley APCD requires that applications for wood burning device registration and registration renewal contain certifications by District Registered Wood Burning Heater

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Professionals (Rule 4901 Sections 5.7.3.1.2 and 5.8.2.1). Section 5.10 of the Rule specifies the requirements for registration by the District of Wood Burning Heater Professionals. The primary requirement is to hold a current Fireplace Investigation Research and Education Certified Inspector registration, Chimney Safety Institute of America certificate, or National Fireplace Institute certificate.

Fairbanks had a regulations requiring installations of solid fuel burning appliances in new construction and replacement appliances in subsidized change-outs be performed by Borough-listed vendor/installers using Borough-listed appliances. Those regulations, however, were removed with the passage of the Home Heating Reclamation Act and the state had no regulations addressing professional installation confirmation or on-site inspection.

Analysis

Lacking a regulation governing the certification of heating professionals, the state has implemented new regulations 18 AAC 50.077(k)(2) & (3) requiring the certification of installers by the National Fireplace Institute or Masonry Heaters Association as appropriate.

Conclusion

The adoption of the referenced state regulation is sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 6: Prohibit Installation of Flue Dampers Unless Device was Certified Using Flue Damper

Applicable Jurisdiction(s)

- Missoula, Montana

Regulation Weblink(s)

- https://www.missoulacounty.us/home/showdocument?id=8452

Background

With respect to enclosed combustion devices, the term "draft" refers to the negative pressure created at the air inlet to the combustion chamber by the buoyancy of hot combustion gases exiting the combustion chamber through a vertical stack or chimney. The magnitude of stack draft is primarily governed by the difference in temperature between outdoor air and the combustion gases within the stack, and the volume of the stack (or chimney). Since outdoor air and stack gas temperatures change both seasonally and during a typical diurnal heating cycle, the amount of draft can vary similarly.

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In residential wood stoves and inserts, inlet air and combustion gas flow rates are generally controlled by a damper installed at the inlet air ports to the combustion chamber. Where building codes and wood burning regulations allow, dampers can also be installed downstream of the combustion chamber in the exhaust stack to directly regulate combustion gas flow rates. Many dampers require manual adjustment, but some are thermostatically controlled to open the damper when combustion chamber temperatures decline during the burndown phase.

Solid fuel burning appliances are designed to operate within an optimum draft range. If the draft is set too low, insufficient air is available to sustain combustion except when very small quantities of fuel are present in the combustion chamber. If the draft is set too high, excess air (beyond what is needed for proper combustion) is allowed into the combustion chamber which reduces combustion temperatures and reduces the device's heating efficiency (resulting in increased fuel use) and may also result in unsafe operation. The optimum range of draft for properly installed and operated residential wood-burning devices such as wood stoves and fireplace inserts typically falls in the negative pressure range of minus 0.04 to 0.08 inches of water column.

EPA commented "The discussion of Measure 6 may need additional documentation. Anecdotal evidence is that damping is common in Fairbanks and is potentially a bigger source of pollution than not having a damper at very cold conditions. If installation by a certified technician addresses this issue that should be documented."

Analysis

Missoula, Montana is the only jurisdiction to enforce a regulation prohibiting the installation of a flue (exhaust stack) damper unless the device is specifically certified with a flue damper. The staff from the Montana Department of Environmental Quality could not locate a staff report associated with the adoption of this regulation by their Board in 1986 as part of the Montana Clean Air Act. They also suggested that no analysis was conducted to review the likely impact of flue damper installation on emissions prior to adoption.[16]

During wintertime conditions in Fairbanks flue draft varies dramatically beyond the optimal range due to wider temperature differences between flue gases and ambient air. When outdoor temperatures fall to the -10 to -20°F range typical of ambient $PM_{2.5}$ violations in Fairbanks, draft negative pressures can reach or exceed minus 0.20 inches of water column, which is well in excess of the typical design ranges for wood stoves and inserts.[17] Under these conditions, resident time of hot combustion gases in a wood stove or fireplace insert will be reduced, increasing the quantity of fuel needed to be burned to maintain the target indoor temperature. Thus, use of a flue damper will reduce inlet air and exhaust gas flowrates and the resulting draft to within the designed operating ranges of woodstoves and fireplace inserts and provide an emissions reduction benefit through reduced fuel consumption. With regard to the installation of

[16] Personal communication with Julie Mohr, Montana Department of Environmental Quality, October 5, 2017; Personal communication with Benjamin Schmidt, Missoula City/County Health Department, October 6, 2017.
[17] Personal communication with Kent Severns, The Woodway, Fairbanks, AK, October 6, 2017.

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new wood burning devices, the 2015 NSPS mandates that owner manuals specify whether flue dampers are required and professional installers are required to observe installation instructions. If required, 18 AAC 50.077(j) requires the use of installers certified by the National Fireplace Institute and/or the Masonry Heaters Association as appropriate, which addresses EPA's comment.

Conclusion

The benefits of this measure in an arctic environment are likely to increase emissions through increased fuel combustion. Thus this rule will produce no benefit for new installations; therefore the measure is technologically infeasible and not eligible for consideration as BACM.

Measure 7: Require Devices Meet Stricter Emission Criteria in High Pollution Zones

Implementing Jurisdiction(s)

- Missoula City-County MT

Regulation Weblink(s)

- https://www.missoulacounty.us/home/showdocument?id=8452

Background

The Missoula City-County wood heating control regulations require installation permits for the installation and use of all wood heating devices after July 1, 1986 in the Air Stagnation Zone (Section 9.202.1) and May 14, 2010 in the remainder of Missoula County (Section 9.202.2). The categories of devices authorized for installation differ between the two areas. Within the Air Stagnation Zone, installation permits are authorized only for pellet stoves emitting no more than 1.0 gm/hr (Section 9.203.1.a). In the remainder of Missoula County, installation permits can be issued to devices complying with 40 CFR 60 AAA (effective February 26, 1988), pellet stoves emitting no more than 4.1 gm/hr, and outdoor wood-fired hydronic heaters emitting no more than 7.5 gm/hr (Section 9.204.1.a-d).

Fairbanks enforced a single set of approved device types for installation within the nonattainment area. The regulations addressing this requirement was removed with the passage of the Home Heating Reclamation Act and the state had no regulations addressing installation permits.

Analysis

Lacking regulations specifying emission rate criteria for heating devices installed in the nonattainment area, the state has implemented new regulations 18AAC 50.077(c), (d), (e), (f), (g), (h,), (i), (j) which specify the EPA emission rates new heating devices must meet in order to

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be installed. These regulations are presented in the introduction and collectively exceed the Missoula City-County wood heating control regulation requirements.

Conclusion

The adoption of the referenced state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 8: Prohibit Installation of Solid Fuel Heating Device in New Construction

Implementing Jurisdiction(s)

- South Coast AQMD, Bay Area AQMD

Regulation Weblink(s)

- http://www.aqmd.gov/docs/default-source/rule-book/rule-iv/rule-445.pdf?sfvrsn=4
- http://www.baaqmd.gov/~/media/files/planning-and-research/rules-and-regs/reg-06/rg0603.pdf?la=en

Background

The South Coast Air Quality Management District prohibits the installation of a wood-burning device into any new construction (Section 445.d.1) except in new developments where no natural gas service exists within 150 feet of the property line (Section 445.f.2). Devices installed in new construction without natural gas service are limited to USEPA certified wood-burning heaters, pellet stoves, masonry heater, or dedicated gaseous-fueled fireplaces (Section 445.d.2). South Coast AQMD does not require a permit for device installation or operation.

Bay Area Air Quality Management District prohibits the installation of a wood-burning device in any new construction building effective November 1, 2016 (Section 6-3-306). The Bay Area regulation does not provide an exemption from this requirement in areas not served by natural gas infrastructure.

Fairbanks had regulations addressing the installation of solid fuel devices in new construction, but, they were removed with the passage of the Home Heating Reclamation Act. The state had no regulations governing installation of wood-burning devices.

Analysis

While Fairbanks currently has natural gas service, it is capacity constrained and will not be in a position to expand service to new customers until 2020 (i.e., after the designated attainment

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year).[18] As a result, the installation requirements in the South Coast rule that would be applicable if adopted by the state would be limited solely to the type of device installed.

As noted in Measures 3, 4, 5 and 7, the state has implemented new regulations that establish strict emission ratings for new heating devices and related installation requirements. Those regulations, however do not prohibit the installation of wood-burning devices in new construction. Backup heating systems are essential for survival in an arctic environment as loss of primary heating is not an uncommon occurrence with many causes including: extreme cold temperatures, ice storms, fuel supply loss, etc. Not a winter goes by that primary heating systems either fail due to supply loss or fail to provide sufficient heat needed to cope with extreme cold temperatures. For this reason, a lower-48 requirement to prohibit the installation of solid fueled heating device in new construction is inappropriate for an arctic environment.

Conclusion

This measure is technologically infeasible in an arctic environment.

Measure 9: Limit the Density of Solid Fuel Heating Devices in New Construction

Implementing Jurisdiction(s)

- San Joaquin Valley APCD, Eastern Kern APCD

Regulation Weblink(s)

- https://www.valleyair.org/rules/currntrules/r4901.pdf
- http://www.kernair.org/Rule%20Book/4%20Prohibitions/416_1%20Wood%20Burning%20Heaters%20and%20Fireplaces.pdf

Background

The San Joaquin Valley Air Pollution Control District in California limits the number of wood burning heaters allowed in new residential developments. Two limits apply to developments with housing densities greater than 2 residences per acre: no wood burning fireplaces may be installed in these residences, and no more than two U.S. EPA Phase II-certified wood heaters may be installed per acre in these residences. For developments with housing densities less than or equal to two residences per acre, the regulation allows no more than one wood burning fireplace or U.S. EPA Phase II-certified wood heater per residence. (Section 4901.5.3.2)

The Eastern Kern Air Pollution Control District in California prohibits the installation of wood burning fireplaces in new residential subdivisions that consist of 10 or more dwellings. (Section 416.1.VI)

[18] AIDEA IGU Financing Agreement op. cit., Appendix A

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Fairbanks allowed for the installation of solid fuel burning devices in new construction provided that permits had been issued by the Borough, devices were Borough-listed, and installation was performed by a Borough-listed installer, among other requirements. These regulations were removed after passage of the Home Heating Reclamation Act.

Analysis

Alaska DEC does not have the information or programs to address land use authority required to limit the number of solid fuel burning devices that can be installed in single dwellings newly constructed, nor limit the number of devices that can be installed per acre in new residential developments. Multiple years would be required for DEC to gather data and evaluate options, possibly obtain necessary authority, and establish the regulatory requirements to implement this measure.

Conclusion

The timing required to adopt this measure precludes its consideration as BACM, therefore it should be addressed in a subsequent SIP as a MSM.

Measure 10: Install EPA-Certified Device Whenever a Fireplace or Chimney is Remodeled

Implementing Jurisdiction(s)

- Bay Area AQMD

Regulation Weblink(s)

- http://www.baaqmd.gov/~/media/files/planning-and-research/rules-and-regs/reg-06/rg0603.pdf?la=en

Background

The Bay Area AQMD requires that a gas-fueled, electric, or EPA-certified device be installed whenever a fireplace or chimney is remodeled at a cost that exceeds $15,000 and requires a local building permit (Section 6-3-307).

Fairbanks limited wood heating devices in new construction to Borough-listed appliances (Section 21.28.030E), but did not require the replacement of non-Borough-listed appliances with listed versions upon the remodeling of a residence or of a fireplace or chimney. These regulations were removed after passage of the Home Heating Reclamation Act.

Analysis

The Bay Area AQMD measure would require the upgrading of wood heating appliances in affected Borough residences in which remodeling projects included fireplace or chimney

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modifications that exceeded $15,000 in cost. Alaska DEC does not have the information or programs to address land use/building code authority needed to govern building/remodeling permits. Multiple years would be required for DEC to gather data and evaluate options, possibly obtain necessary authority, and establish the regulatory requirements to implement this measure.

Conclusion

The timing required to adopt this measure precludes its consideration as BACM, therefore this measure is classified as a MSM to be addressed in a subsequent SIP.

Measure 11: Prohibit Use of Rain Caps on Stacks

Implementing Jurisdiction(s)

- State of Maine

Regulation Weblink(s)

- https://www1.maine.gov/sos/cec/rules/06/096/096c150.doc

Background

Outdoor wood boilers (OWBs) are generally used to provide heat for residential structures. Firewood is burned in the unit, sited outside the residence, with the energy released by combustion transferred to the residence through circulation of a thermal fluid.

In some locations, operators of outdoor wood boilers attach a rain cap (or weather cap) to the stack from which emissions produced by the outdoor wood boiler are released. This rain cap is attached to prevent moisture (rain, snow, etc.) from entering the stack during periods of non-operation and causing exposed surfaces to rust.

EPA commented that the quote "did not know if the rule worked well" needs a reference. Also EPA expressed concern about how the performance of a control measure in Maine makes it technologically in feasible in Fairbanks.

Analysis

Maine is the only jurisdiction that currently enforces a regulation related to the use of rain caps on outdoor wood boiler stacks, prohibiting the installation of caps unless specifically required by the manufacturer of the boiler.[19] Personal communications with staff members of the Maine Department of Environmental Protection indicated that the regulation was adopted in Maine between 2007 and 2008 primarily in response to complaints from citizens about the use of

[19] Regulation can be downloaded at http://www.maine.gov/dep/air/woodsmoke/woodcombustion.html

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boilers by neighbors.[20] More than one staff member indicated that no scientific or statistical analysis was conducted by the staff during development of the regulation. One said specifically that he "did not know if the rule had worked well," and one said that only one comment was entered into testimony in the meeting at which the Maine DEQ Board adopted the regulation; the only responsive in the record mentioned that the use of a rain cap impeded buoyant plume rise of smoke exiting a stack and resulted in higher ground-interior level impacts at downwind residences. [21]

The average precipitation rate in Fairbanks is much lower than that of Maine, particularly in the winter months. Whereas Maine averages more than forty inches of precipitation per year, Fairbanks averages less than eleven.[22,23] In addition, whereas ~54%, or 22 inches, of Maine's precipitation falls during the winter nonattainment months (October through March), only 31%, or 3 inches, of precipitation in Fairbanks falls during those months. Discussions with Fairbanks North Star Borough Air Quality Program staff found that rain caps are not used in Fairbanks, and thus a regulation prohibiting rain caps would have no impact on emissions;[24] thus, addressing EPA's concerns.

Conclusion

The prohibition of rain caps by Maine DEC was intended to improve smoke dispersion, not reduce emissions. Because of the very low inversion heights that are experienced in Fairbanks during the winter heating season, a prohibition of rain caps would not improve plume dispersion in the vertical direction, much less reduce emissions. Since the need for rain caps in Fairbanks is limited and Borough staff have previously indicated that existing OWBs are not equipped with them, a regulation prohibiting rain caps on OWB stacks would produce no emission benefit and is therefore technologically infeasible and not eligible for consideration as BACM.

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[20] Personal communication on October 4, 2017 with Jeff Crawford, Air Bureau, Maine Department of Environmental Protection; Personal communication on October 5, 2017 with Tom Graham, Air Bureau, Maine Department of Environmental Protection.
[21] Personal communication on October 4, 2017 with Jeff Crawford, Air Bureau, Maine Department of Environmental Protection; Personal communication on October 5, 2017 with Tom Graham, Air Bureau, Maine Department of Environmental Protection.
[22] Data collected for Portland, ME; Augusta, ME; and Lewiston, ME from U.S. Climate Data at https://www.usclimatedata.com/climate/maine/united-states/3189; Accessed 10/12/2017.
[23] Data collected for Fairbanks, AK from U.S. Climate Data at https://www.usclimatedata.com/climate/fairbanks/alaska/united-states/usak0083; Accessed 10/12/2017.
[24] Personal communication with Todd Thompson, Fairbanks Borough Air Quality Department, October 10, 2017.

Measure 12: Require Minimum Stack Height for OWBs Relative to Nearby Rooflines

Applicable Jurisdiction(s)

- State of Maine

Regulation Weblink(s)

- http://www.maine.gov/dep/air/woodsmoke/woodcombustion.html

Background

Outdoor wood boilers (OWBs) are generally used to provide heat for residential structures. Firewood is burned in the unit, located outside the residence, with the energy released by the combustion process transferred into the interior of the residence through circulation of a thermal fluid.

The boilers generate emissions by the combustion of wood fuel, and those emissions can be transported to impact neighboring residences. Ground-level concentrations of emissions at downwind residences can be influenced by the heights at which emissions exit exhaust stacks and whether wind flows at exit points are impacted by the heights of structures near these exhaust stacks.[25]

Maine is the only state that currently regulates the minimum height of exhaust stacks serving newly-installed OWBs. The regulation specifies a minimum stack height of ten feet or "two feet higher than the peak of the roof of the structure being served by the OWB" if:

1) the OWB has a particulate emission rating greater than 0.60 lbs/MMBtu and is within 500 feet of any nearby residence, or
2) the OWB has a particulate emission rating of 0.60 lbs/MMBtu or less and is within 300 feet of any nearby residence.[26]

Additionally, the regulation requires the extension of an existing OWB exhaust stack if a new residence is constructed within the setback distances specified in the regulation.

Analysis

As with the Maine-only regulation prohibiting the use of rain caps on OWB exhaust stacks, staff members of the Maine Department of Environmental Protection reported that the regulation was

[25] Minnesota Pollution Control Agency, AERMOD Evaluation of Outdoor Wood Boiler Stack Height and Setback

[26] Regulation can be downloaded at http://www.maine.gov/dep/air/woodsmoke/woodcombustion.html

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adopted in Maine between 2007 and 2008 primarily in response to nuisance complaints from citizens about the use of OWB by neighbors.[27] More than one staff member indicated that no scientific or statistical analysis was conducted by the staff during development of the regulation to estimate its benefits. One said specifically that he "did not know if the rule had worked well," and one said that no public comments were received in relation to the stack height requirements prior to or during the public hearing at which the Maine DEQ Board adopted the regulation.

Maine adopted this rule to minimize disputes between neighbors; the rule has no effect on emissions and was not developed to reduce ambient $PM_{2.5}$ concentrations other than at nearby downwind residences. The rule predates federal regulation of OWBs, which mandates that owner manuals provide "guidance on proper installation information, including stack height".[28] A survey of owner manuals found installation instructions specifying that chimney height extend above the roofs of surrounding buildings.[29] Industry guidance contained in Best Burn Practice for Wood Burning Outdoor Furnace recommends that stack extend 2 feet above surrounding roof top peaks.[30]

The addition of a regulation specifying minimum stack heights for OWBs would not lead to a reduction in $PM_{2.5}$ emissions but could reduce $PM_{2.5}$ concentrations downwind of newly-installed OWBs or newly-constructed residences near OWBs.

Conclusion

Because of the lack of any emission reduction resulting from adoption of a minimum stack height regulation, this measure is technologically infeasible and not eligible for consideration as BACM.

Measure 13: Submit Sale and Installation Information to Air Program

Implementing Jurisdictions

- State of New York

[27] Personal communication on October 4, 2017 with Jeff Crawford, Air Bureau, Maine Department of Environmental Protection; Personal communication on October 5, 2017 with Tom Graham, Air Bureau, Maine Department of Environmental Protection.
[28] https://www.federalregister.gov/documents/2015/03/16/2015-03733/standards-of-performance-for-new-residential-wood-heaters-new-residential-hydronic-heaters-and
[29] https://centralboiler.com/media/1803/9000166_manual_classic_27-jan-2014.pdf
[30] https://www.hpba.org/Portals/26/Documents/Government%20Affairs/NSPS%20Members/HPBA%202014%20NSPS/Attachment13TechEnvironmentalAirDispersionModelingReportofEClassic2300July2012.PDF?ver=2016-11-21-105529-197

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Regulation Weblink(s)

- https://govt.westlaw.com/nycrr/Browse/Home/NewYork/NewYorkCodesRulesandRegulations?guid=I591033205f9311e0b70f0000845b8d3e&originationContext=documenttoc&transitionType=Default&contextData=(sc.Default)

Background

The New York Department of Environmental Conservation requires the distributor of new outdoor wood boilers (OWB) to provide prospective buyers with a written notice of fuels allowed to be burned in OWBs and a statement that OWBs cannot be operated in locations where emissions unreasonably interfere with the public health of and enjoyment of property by others (6 CRR-NY 247.9.a). This regulation also requires the distributor to submit to the Department a statement signed by the OWB buyer acknowledging receipt of the written notice provided by the distributor and containing information on the location, manufacturer, stack height, and distance to the nearest property boundary of the installed OWB (6 CRR-NY 247.9.b). To be certified for sale in the State of New York, OWBs must be certified to emit not more than 0.32 lb/MMBTU $PM_{2.5}$ using year-round weighting factors specified in the listed test method (6 CRR-NY 247.5.a). OWBs must be installed at least 100 feet from the nearest property boundary (6 CRR-NY 247.5.b).

Fairbanks had regulations requiring commercial sellers of solid fuel burning appliances to provide the prospective buyer with a written notice that summarizes Borough fuel restrictions; installation, property location, operation and maintenance requirements, and an advisory that installation in some areas may not be appropriate. Those regulations disappeared with the passage of the Home Heating Reclamation Act. The state had no regulations governing home heating installation requirements or related information disclosure.

EPA commented that the analysis "identified that no SIPs existed or EPA guidance/requirements for the measure and incorrectly used that rationale as the conclusion for not considering the measure".

Analysis

The New York DEC measure allows for the installation of OWBs emitting 0.32 lb/MMBTU $PM_{2.5}$ or less, whereas new state regulation 18 AAC 50.077(d) prohibits the sale of non-pellet fueled hydronic heaters. The new state regulation also requires pellet fueled hydronic heaters must be certified to 0.10 lb/MMBTU or less to be installed in new construction. In addition hydronic heaters not meeting this requirement must be removed or replaced by December 31, 2024. Another new subsection 18 AAC 50.077(k)(1) requires curtailment information and proper operating instructions to be conveyed at the time of sale. While the new state regulations do not require a signed statement from the buyer acknowledging receipt of information on fuels to be burned and location restrictions, the pellet restriction for new hydronic heaters trumps the need for information on fuels to be burned. With regard to the setback requirement from the nearest property boundary, 18 AAC 50.077(d)(3) restricts installation of pellet fueled hydronic heaters to

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more than 330 feet from the closest property line or more than 660 feet from a school, clinic, hospital, or senior housing unit, which is much more stringent than the 100 foot setback requirement established by New York. An additional consideration is that, the setback requirement has no effect on the emission rate, which will be significantly lower than mandated by New York.

EPA's concerns are addressed the through the adoption of the regulations noted above.

Conclusion

The adoption of the referenced state regulation is sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 14: Require Installation of Thermal Mass to Improve Efficiency and Prevent Frequent Cycling in Selected New Units

Implementing Jurisdiction(s)

- None

Regulation Weblink(s)

- None

Background

The initial review of applicable SIPs and EPA guidance documents mistakenly identified a measure requiring the installation of thermal mass to prevent frequent burn cycling in hydronic heaters.

Analysis

A review of the literature, applicable SIPs, EPA guidance documents, hydronic heater certification documents and the final rule for hydronic heaters issued in 2015 (Standards of Performance for New Residential Wood Heaters, New Residential Hydronic Heaters and Forced-Air Furnaces)[31] could find no requirements for installing thermal mass in hydronic heaters. The final rule for hydronic heaters and forced air furnaces discussed concerns about cycling conditions, operations, etc., but included no requirement for the addition of thermal mass to reduce cycling.

[31] https://www.gpo.gov/fdsys/pkg/FR-2015-03-16/pdf/2015-03733.pdf

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Conclusion

No SIPs or EPA guidance was identified requiring the addition of thermal mass to reduce hydronic heater cycling; therefore, this measure is not eligible for consideration as BACM, but is classified as a MSM to be addressed in a subsequent SIP.

Measure 15: Disclosure of Devices on Property Sale

Implementing Jurisdiction(s)

- Lane Regional APA

Regulation Weblink(s)

- https://secure.sos.state.or.us/oard/displayDivisionRules.action?selectedDivision=1567

Background

The Lane Regional Air Protection Agency enforces regulations adopted by the State of Oregon with respect to the transfer of residential property containing SFBDs. Oregon Administrative Rule 340-262-0700 requires the removal and destruction of all devices not certified for sale as new by the Oregon Department of Environmental Quality or the USEPA, and those devices not permanently labeled as certified, upon the transfer of residential property. This Rule also requires disclosure to Oregon Department of Environment Quality of the removal and destruction of uncertified devices. The Rule does not exempt uncertified devices in NOASH households from removal and destruction requirements. Certified devices are defined in Oregon Administrative Rule 340-262-0500 as devices certified by USEPA as of July 1, 2010. The USEPA certification PM2.5 emission limits in 2010 were 4.1 gm/hr for catalyst-equipped wood stoves and 7.5 gm/hr for non-catalyst wood stoves.

Previous Alaska regulations prohibited the conveying of ownership of any wood stove not certified by USEPA to meet a PM2.5 emission limit of 2.5 gm/hr in the Fairbanks nonattainment area as part of a property sale (Section 18 AAC 50.077.c). As this emission limit is more stringent than 2010 USEPA certification standards, the ODEQ measure is less stringent than existing Fairbanks regulations with respect to wood stove removal upon the transfer of residential property ownership. Those regulations have been repealed and replaced.

Prior to approval of the Home Heating Reclamation Act, Fairbanks prohibited the installation of a solid fuel burning appliance in new construction without an installation permit issued by the Borough (Section 21.28.030.E.1.a). Fairbanks also prohibited the sale of appliances not certified by USEPA to meet a $PM_{2.5}$ emission limit of 2.5 gm/hr unless the buyer signs an affidavit attesting that the appliance will not be installed or used in the nonattainment area, and submits the affidavit to the Borough. These regulations were removed from Borough Code following voter approval of the Home Heating Reclamation Act.

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EPA commented that (1) the discussion of Measure 15 did not clearly state how Alaska would ensure devices are taken out at the point of sale, (2) the process for ensuring that NOASH applications did not involve a stove that should have been taken out at the point of sale and (3) there was confusion about the threshold for NOASH eligibility.

Analysis

The Oregon DEQ regulation causes devices certified by USEPA to meet $PM_{2.5}$ emission limits up to 7.5 gm/hr to remain in residences during property transfers. By comparison, Alaska's new regulations 18 AAC 50.077(b) specify that a person may not operate, install, reinstall, sell, lease, distribute, or convey wood-fired heating devices that lack a valid EPA certification under 40 C.F.R. 60.533 or any wood-fired outdoor hydronic heaters, except pellet fueled devices, including those that have a qualifying "white tag" under EPA's Phase 2 voluntary partnership program. All noncompliant devices must be removed or replaced by December 31, 2024, removed or replaced prior to property conveyance and destroyed or rendered inoperable. The new state regulation 18 AAC 50.077(k)(2) also requires confirmation of removal and destruction of any existing device shall be provided to the department. The emission limits under C.F.R. 605.33 are more stringent (i.e., 4.5 g/hr for devices meeting 2015 standards and 2.0 g/hr for devices meeting 2020 emission standards) than the 7.5 g/hr threshold in the Oregon DEQ regulations. The removal, destruction and confirmation requirements in the new Alaska regulations are consistent with those contained in the Oregon DEQ regulations.

In response to the EPA comments, the above discussion addresses concerns about how devices are taken out at the point of sale. With regard to the NOASH applications and eligibility concerns the new Alaska regulations offer no exemptions for NOASH compliant devices. The only exemptions are for those receiving temporary waivers and the transfer of devices outside of the nonattainment area. Under 18 AAC 5077(m) the threshold for removal drops to 2.0 g/hr if there is a finding of failure to attain the NAAQS for $PM_{2.5}$, a finding of failure to meet a qualitative milestone, or a finding for failure to meet reasonable further progress.

Conclusion

The adoption of the referenced state regulation is sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 16: Require Notice and Proof of Destruction or Surrender of Removed, Uncertified Devices

Implementing Jurisdiction(s)

- Puget Sound CAA

Regulation Weblink(s)

- https://www.pscleanair.org/DocumentCenter/Home/View/557

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Background

The Puget Sound Clean Air Agency in the State of Washington required the removal of, or modification to render permanently inoperable, all uncertified wood stoves in residences and commercial establishments within the Tacoma, Pierce County $PM_{2.5}$ nonattainment area by January 1, 2015. (Section 13.07.a.1) To assure compliance, the agency also required the person removing or modifying an uncertified wood stove to provide to the agency documentation of the removal and disposal or rendering permanently inoperable of each affected device. Documentation of such actions must conform to agency requirements and procedures and be provided to the agency within 30 days of wood stove removal or modification. (Section 13.07.a.4)

During a first stage of impaired air quality as declared by PSCAA, all solid fuel burning devices within the affected geographical area must cease operating except for (a) nonaffected pellet stoves; (b) wood stoves certified under 40 CFR 60 Subpart AAA (7/1/1990); wood stoves meeting Oregon DEQ Phase 2 emission standards (November 1984); (c) solid fuel burning devices certified by Washington Department of Ecology, or devices in residences or commercial buildings deemed exempt from curtailment requirements by PSCAA due to having no other adequate source of heat (NOASH). (Section 13.05.a.1, 13.05.d.1)

Fairbanks had no requirement to remove uncertified wood stoves by a fixed date, but did prohibit their use during a Stage 1 Alert. Those requirements disappeared with the approval of the Home Heating Reclamation Act. Alaska had no regulations addressing the removal, proof of destruction or surrender of uncertified devices.

EPA commented that the Tacoma and Pierce County removal requirements appeared more stringent than those in the Moderate SIP approved Fairbanks ordinance (no longer in place) and that the information provided did not support the conclusion that Fairbanks controls (also no longer in place) provide equivalent or more stringent control. EPA also commented that date certain removal needed to be considered for the nonattainment area.

Analysis

Alaska's new regulations 18 AAC 50.077(b) specify that a person may not operate, install, reinstall, sell, lease, distribute, or convey wood-fired heating devices that lack a valid EPA certification under 40 C.F.R. 60.533 or any wood-fired outdoor hydronic heaters, except pellet fueled devices, including those that have a qualifying "white tag" under EPA's Phase 2 voluntary partnership program. All noncompliant devices must be removed or replaced by December 31, 2024, removed or replaced prior to property conveyance and destroyed or rendered inoperable. The new state regulation 18 AAC 50.077(k)(2) also requires confirmation of removal and destruction of any existing device shall be provided to the department. Alaska's new date certain removal requirements are significantly more stringent than Puget Sound's removal requirements, which only address uncertified wood stoves, which satisfies one of EPA's comments.

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Alaska's new Alert thresholds (20 µg/m^3 and 30 µg/m^3 respectively for Stage 1 and Stage 2 restrictions) established in the Episode Chapter, presented in the introduction, are significantly more stringent than Washington State thresholds established in WAC 173-433-140 (the more stringent for Pierce, Snohomish, and Yakima counties set values of 30 µg/m^3 and 25 µg/m^3)

The emission limits under C.F.R. 605.33 are more stringent (i.e., 4.5 g/hr for devices meeting 2015 standards and 2.0 g/hr for devices meeting 2020 emission standards) than 7.5 g/hr threshold in the Oregon DEQ regulations. This means that when Alerts are called in Fairbanks at lower thresholds more restrictive requirements apply to the wood stove allowed to burn. These requirements satisfy EPA's concern about stringency of the applicable controls.

Conclusion

The adoption of the referenced state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 17: Require Removal of Uncertified Solid Fuel Burning Devices Upon Sale of Property

Applicable Jurisdiction(s)

- State of Oregon

Regulation Weblink(s)

- https://www.oregonlegislature.gov/bills_laws/ors/ors468A.html
- http://www.deq.state.or.us/regulations/rules/excerpt/262-20110309-Rule.pdf

Background

The Oregon legislative body, under Senate Bill 102,[32] in 2009 extended legislation relating to solid fuel burning devices to reduce the number of uncertified wood burning devices in the state. Among other additions, they included the requirement that sellers of properties that contain uncertified solid fuel burning devices bear the responsibility of the removal and destruction of those devices unless the seller and buyer agree in writing that the responsibility was to become the buyer's. If the seller retains responsibility, the device needs to be removed from the structure prior to the closing date of sale of the structure. If the buyer is to accept responsibility, the buyer must remove and destroy the device within 30 days of closure of sale of the property. In addition, the person responsible for removal and destruction of the device must show proof of such to the Oregon Department of Environmental Quality (ODEQ).

[32] https://olis.leg.state.or.us/liz/2009R1/Measures/Overview/SB102

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Following enactment of this legislation, the ODEQ also adopted a series of regulations in 2011 to implement the requirements of Senate Bill 102.[33] ODEQ Regulation 340-262-0700[34] requires the same procedure for uncertified solid fuel burning devices in Oregon prior to or shortly after sale of a property. The resulting program came to be known as Oregon's Heat Smart program.[35]

Fairbanks had regulations affecting the removal of uncertified wood burning devices during property transactions in Fairbanks that became effective June 9, 2017.[36] Those regulations required removal or replacement of non-compliant wood-fired heating devices before the sale, lease, or conveyance of property within the Nonattainment Area. The regulations were intended to improve air quality by reducing the number of older, more polluting wood-fired heating devices in the area over time. Wood-fired devices that appear on any of DEC's lists of EPA-certified and Phase 2 "White Tag" devices did not need to be removed or replaced. Those regulations were removed after passage of the Home Heating Reclamation Act.

EPA commented that the conclusion of Measure 17 referenced Fairbanks, but the analysis referred to AAC code. This inconsistency disappeared with the deletion of the referenced Fairbanks regulations.

Analysis

There were some exceptions and the ability for temporary waivers under 18 AAC 50.077 (h) which allowed temporary waivers. Those regulations have been repealed and replaced. Alaska's new regulations 18 AAC 50.077(b) specify that a person may not operate, install, reinstall, sell, lease, distribute, or convey wood-fired heating devices that lack a valid EPA certification under 40 C.F.R. 60.533 or any wood-fired outdoor hydronic heaters, except pellet fueled devices, including those that have a qualifying "white tag" under EPA's Phase 2 voluntary partnership program. All noncompliant devices must be removed or replaced by December 31, 2024, removed or replaced prior to property conveyance and destroyed or rendered inoperable. The new state regulation 18 AAC 50.077(k)(2) also requires confirmation of removal and destruction of any existing device shall be provided to the department. Alaska's new removal requirements are significantly more stringent than Oregon's removal requirements, which only address uncertified wood stoves. The confirmation, destruction and notification requirements are consistent with those specified in the Oregon regulations.

Subsection (j) of 18 AAC 50.077 does not apply to the conveyance of a wood-fired heating device if the owner requests and receives a temporary waiver from the department or a local air quality program. Temporary waivers may be granted for the following considerations:

(1) financial hardship information provided by the owner or operator;

(2) technical feasibility information provided by the owner or operator; and

[33] http://www.oregondeq.com/regulations/rules/summary/262-20110121-Summary.htm
[34] http://www.deq.state.or.us/regulations/rules/excerpt/262-20110309-Rule.pdf
[35] http://www.oregon.gov/deq/Residential/Pages/heatsmart.aspx
[36] http://dec.alaska.gov/air/anpms/comm/docs/18AAC50.077.pdf

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(3) potential impact to locations with populations sensitive to exposure to PM-2.5; locations under this paragraph include hospitals, schools, child care facilities, health clinics, long-term care facilities, assisted living homes, and senior centers.

Alaska's new removal requirements prior to sale are considerably more stringent than Oregon's which only apply to uncertified solid fuel devices. Oregon allows the purchaser up to 30-days to remove uncertified devices after the transaction is completed; Alaska DEC does not. DEC allow a temporary waiver that increases the time for removal for a limited category of transactions. The limited increase in emissions associated with the temporary waivers is more than offset by the higher stringency of devices impacted by Alaska's new regulations.

Conclusion

The adoption of the referenced state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 18: No Visible Emissions during Curtailment Periods

Applicable Jurisdiction(s)

- Maricopa County, Arizona

Regulation Weblink(s)

- https://www.maricopa.gov/DocumentCenter/View/5332

Background

A Maricopa County ordinance[37] allows wood stoves certified as the sole source of heat in a residential dwelling to continue operating during curtailment periods provided that these stoves emit no visible emissions, i.e. 0% opacity. Most other jurisdictions with wood burning regulations limit visible emissions from wood stoves permitted to operate during curtailment periods to 20% opacity.

Communication with staff members from Maricopa County's Air Quality Department indicated that no staff report was prepared when the "no visible emission" regulation was first adopted in 1994.[38] Communication with a staff member from Montana's Department of Environmental

[37] Ordinance P-26, Section 3.C.1 of Maricopa County Ordinance P-26: Residential Woodburning Restriction, available at https://www.maricopa.gov/DocumentCenter/View/5332; accessed October 12, 2017.
[38] Personal communication with Johann Kuspert, Maricopa County Air Quality Department, September 28, 2017.

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Quality indicated that Montana, where ambient temperatures during the winter nonattainment season can drop to low levels that approach those in Fairbanks, maintains a restriction that allows visibility up to 20%.[39] Historical EPA literature states that "It can be difficult to distinguish pollutant-containing mists from innocuous water droplets that are generated from steam condensation,"[40] and advises inspectors that "if the temperature is low...consider the possibility of a steam plume that does not evaporate easily."[41] Academic literature summarizing EPA's Method 9 states:

> In cold weather, steam is often a part of the emission. In order to make an accurate reading, opacity must be read after the steam has dissipated. This change is readily visible as the apparent opacity will drop significantly but stay constant after that.[42]

Analysis

Two additional considerations in Fairbanks are that (1) daylight is limited during winter months to no more than 5 hours/day in December, January and February, the period when elevated $PM_{2.5}$ concentrations are most likely to occur, and (2) oil- and gas-fired heating devices generate condensing moisture plumes but are not required to cease operation during curtailment periods. These factors have led the Borough in the past to develop a checklist of considerations to differentiate between wood/coal stoves and oil/gas furnaces. These considerations include:

- Odor – smelling the smoke is often the first and best indication of wood or coal burning;
- Multiple Stacks – frequently an indication of a secondary heating device besides a furnace;
- Location of Stack – stacks located over a garage connected to the house is typically for an oil/gas furnace; stacks over separated garages and sheds/shops is an indication of a SFBD; stacks located above a common area, such as a living room, are an indication of a SFBD;
- Black Soot around Stack – black residue over snow & around stacks indicates solid fuel burning;
- Dark or Colored Smoke – darker colored smoke can be an indication of low temperature wood burning and coal burning;
- Cycling Smoke Plumes – an abrupt change in the plume is an indication of an oil/gas furnace;

[39] Personal communication with Benjamin Schmidt, Montana Department of Environmental Quality, October 6, 2017.
[40] Rose, Thomas H, Visible Emission Evaluation Procedures Course Student Manual APT/ Course 325 Final Review Draft, 1995, available at https://www3.epa.gov/ttnemc01/methods/VECourse.pdf; accessed October 12, 2017.
[41] Eastern Technical Associates and Entrophy Environmentalist, Inc., Visible Emissions Field Manual EPA Methods 9 and 22, EPA 340/1-92-004, 1993, available at https://www3.epa.gov/ttnemc01/methods/VEFieldManual.pdf; accessed 10-12-2017
[42] University of Nebraska-Lincoln, Safe Operating Procedure: Opacity of Emissions from Combustion Sources and Operating Log Record, 2017, available at https://ehs.unl.edu/sop/s-opacity_emissions.pdf; accessed October 12, 2017.

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- Piles or Stacked Cut Wood – are a clear indication of a wood burning device;
- Exterior chutes – are an indication of a coal burning device;
- Property Database Check – the Borough's database can provide information on original installations, Deed Restrictions, etc.

This checklist allowed Borough field personnel to efficiently determine whether plumes are coming from homes violating Stage 1 or Stage 2 Alerts. Borough personnel were able to survey 40 homes per day during a 5-hour shift (8 homes per hour) to determine compliance with Stage 1 or Stage 2 Alerts. Compliance was determined by observing a SFBD in operation, without the need for an opacity observation. Opacity observations during stage restrictions would add the problem of differentiating steam from particles, compounding the previously identified difficulties of limited daylight and differentiating from oil and gas fired heating devices. A reduction in the limit to zero visibility would require any field staff to monitor each home for a minimum of 20 minutes to identify if a continuous plume with decreasing opacity represents a wood-fired device during startup, and to record the minimum number of observations required by EPA Method 9. Enforcing a zero opacity standard during curtailment would limit the number of homes observed per hour to 2 or less (20+ minutes opacity reading time plus travel time, identification of stacks, etc.). The reduction in the number of homes observed would significantly reduce the identification of Alert violations and benefits of the enforcement program. As a result, implementation of this measure would result in increased emissions during curtailment periods as fewer homes would be inspected for compliance. Fairbanks is no longer enforcing this measure because of the passage of the Home Heating Reclamation Act. While the state is now enforcing this measure under the Episode Chapter of the $PM_{2.5}$ Serious SIP, the same issues noted above apply as the implementation of the measure would lead to a reduction in the number of homes inspected for compliance.

Conclusion

This measure is technologically infeasible because a more stringent visibility standard would reduce the number of homes inspected, reduce the number of violations identified and allow for an increase in wood burning emissions. Therefore, this measure is not eligible for consideration as BACM.

Measure 19: Require Registration of Devices to Qualify for Exemption from Curtailments

Implementing Jurisdiction(s)

- Missoula City-County MT, San Joaquin Valley APCD

Regulation Weblink(s)

- https://www.missoulacounty.us/home/showdocument?id=8452
- https://www.valleyair.org/rules/currntrules/r4901.pdf

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Background

Missoula City-County requires woodstoves to have a valid alert permit in order to continue operating during a Stage 1 Alert (Section 9.205.1). Wood heating devices eligible to receive alert permits include pellet stoves; woodstoves meeting a 6.0 gm/hr $PM_{2.5}$ emission limit that were installed prior to June 30, 1988 and continuously enrolled in the alert permit program since installation; and woodstoves meeting a 4.1 gm/hr emission limit that were installed and continuously enrolled in the alert permit program since October 1, 1994 (Sections 9.205.2 through 9.205.4). Alert permits are valid for five years, except those issued to woodstoves with catalytic converters, which are valid for two years (Section 9.205.7). Permit renewal requires submittal of an application and inspection by the agency or submittal of documentation of adequate maintenance of non-durable parts sufficient to meet applicable emission limitations (Section 9.205.5).

Missoula City-County also allows wood heating devices with valid sole source permits to be operated during Stage 1 Alerts (Section 9.206.1). Wood heating devices eligible to receive new sole source permits are limited to pellet stoves. Devices eligible to receive sole source permit renewals are limited to (1) pellet stoves and (2) woodstoves continuously enrolled in the sole source permit program since July 1, 1985 (Sections 9.206.2 and 9.206.4). Similar exemptions to curtailment requirements are also allowed for wood heating devices with special need permits and with temporary sole source permits (Sections 9.207 and 9.208). All wood heating devices are eligible to receive special need and temporary sole source permits. To qualify, the owners of such devices must qualify for energy assistance under the federal Low-Income Energy Assistance Program – in the case of special need permits – or have a temporarily inoperable primary heating system and satisfy other requirements in the case of temporary sole source permits. Applications documenting compliance with the requirements of either program must be submitted to the agency in order to qualify for the applicable permit (Section 9.209).

San Joaquin Valley APCD prohibits wood-fired heating devices from being operated during a Level One Episodic Wood Burning Curtailment except for USEPA Phase II certified devices and pellet stoves, provided that these are registered with the District (Rule 4901 Section 5.6.1). In areas where natural gas service is not available, registration is not required for a device to be operated during a Burning Curtailment.

Registrations are valid for a period of up to three years. Registration may be renewed by submitting a Registration Renewal application with verification that the wood burning device has been inspected by a Registered Professional to verity that it is maintained pursuant to manufacturer specifications (Section 5.8).

Fairbanks allowed Borough-listed devices to continue operating during a Stage 1 air alert if such devices had approved Stage 1 waivers. Borough-listed devices included USEPA Phase II certified wood stoves, USEPA certified hydronic heaters, masonry heaters, cook stoves, or other devices emitting 2.5 gm/hr or less as documented by accepted testing. Stage 1 waivers did not have expiration dates. These regulations were removed from Borough Code following voter approval of the Home Heating Reclamation Act.

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EPA commented that the Fairbanks requirements lacked the regular renewal and inspection opportunities to verify proper device operation.

Analysis

All three agencies require the registration of permitting of wood heating devices in order to be operated during burning curtailment periods. Alaska's new regulation 18 AAC 50.077(k)(1)(c) requires all wood fired-heating devices to be registered with DEC prior to issuance of any waivers described in the State Air Quality Control plan. The Episode Chapter of that document details the requirement for the issuance of a waiver and the related renewal and inspection requirements separately for non-catalyst equipped and pellet/catalyst equipped devices. All devices require an initial inspection/maintenance verification by a certified chimney sweep. All devices with an emissions rating of >7.5 g/hr are only eligible for 2 annual waivers, lower emitting devices are eligible for longer waiver periods (2, 3 and 5-years). Only devices with an emission rating of <2.0 g/hr are allowed 5-year waivers. These requirements are consistent with those specified in both Missoula City- County and San Joaquin Valley and address EPA's comments.

While Fairbanks currently has natural gas service, it is capacity constrained and will not be in a position to expand service to new customers until 2020 (i.e., after the designated attainment year.[43] Thus, the San Joaquin Valley APCD regulation, which exempts unregistered wood heating devices from curtailment requirements in areas with no natural gas service, is significantly less stringent than the Alaska regulations.

Conclusion

The adoption of the referenced Episode Chapter requirements and state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 20: Require Renewals with Inspection Requirements

Implementing Jurisdiction(s)

- San Joaquin Valley APCD

Regulation Weblink(s)

- https://www.valleyair.org/rules/currntrules/r4901.pdf

Background

San Joaquin Valley APCD prohibits wood-fired heating devices from being operated during a Level One Episodic Wood Burning Curtailment except for USEPA Phase II certified devices and

[43] Appendix A of the Financing Agreement between AIDEA and IGU, December 13, 2017

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pellet stoves, provided that these are registered with the District (Rule 4901 Section 5.6.1). Qualifying wood heaters are eligible for registration by submitting a completed application and supplemental documentation to the District including certification by a District Registered Wood Burning Heater Professional that the device is either a Phase II certified device or a pellet stove (Section 5.7.3.1). If the device for which registration is being sought is more than one year old at the time of initial registration, the application for registration much include proof of inspection by a Registered Professional (Section 5.7.3.1.3). In areas where natural gas service is not available, registration is not required for a device to be operated during a Burning Curtailment.

Registrations are valid for a period of up to three years. Registration may be renewed by submitting a Registration Renewal application with verification that the wood burning device has been inspected by a Registered Professional to verity that it is maintained pursuant to manufacturer specifications (Section 5.8).

Fairbanks allowed Borough-listed devices to continue operating during a Stage 1 air alert if such devices had approved Stage 1 waivers. Borough-listed devices included USEPA Phase II certified wood stoves, USEPA certified hydronic heaters, masonry heaters, cook stoves, or other devices emitting 2.5 gm/hr or less as documented by accepted testing. Stage 1 waivers did not have expiration dates. These regulations were removed after passage of the Home Heating Reclamation Act.

EPA commented that the Fairbanks requirements lacked the regular renewal and inspection opportunities to verify proper device operation.

Analysis

All three agencies require the registration of permitting of wood heating devices in order to be operated during burning curtailment periods. Alaska's new regulation 18 AAC 50.077(k)(1)(c) requires all wood fired-heating devices to be registered with DEC prior to issuance of any waivers described in the State Air Quality Control plan. The Episode Chapter of that document details the requirement for the issuance of a waiver and the related renewal and inspection requirements separately for non-catalyst equipped and pellet/catalyst equipped devices. All devices require an initial inspection/maintenance verification by a certified chimney sweep. All devices with an emissions rating of >7.5 g/hr are only eligible for 2 annual waivers, lower emitting devices are eligible for longer waiver periods (2, 3 and 5-years). Only devices with an emission rating of <2.0 g/hr are allowed 5-year waivers. These requirements are consistent with those specified in San Joaquin Valley and address EPA's comments.

While Fairbanks currently has natural gas service, it is capacity constrained and will not be in a position to expand service to new customers until 2020 (i.e., after the designated attainment year).[44] Thus, the San Joaquin Valley APCD regulation, which exempts unregistered wood heating devices from curtailment requirements in areas with no natural gas service, is significantly less stringent than the Alaska regulations. Thus, implementation of this measure

[44] AIDEA IGU Financing Agreement op. cit., Appendix A

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would have no impact in Fairbanks as all wood-fired heating devices would be exempt from registration and registration renewal.

Conclusion

The adoption of the referenced Episode Chapter requirements and state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 21: Optional Device Registration for Curtailment Exemptions

Implementing Jurisdiction(s)

- San Joaquin Valley APCD; Maricopa County

Regulation Weblink(s)

- https://www.valleyair.org/rules/currntrules/r4901.pdf
- http://www.maricopa.gov/DocumentCenter/View/5332

Background

San Joaquin Valley APCD prohibits wood-fired heating devices from being operated during a Level One Episodic Wood Burning Curtailment except for USEPA Phase II certified devices and pellet stoves, provided that these are registered with the District (Rule 4901 Section 5.6.1). Registration is not required for operation of a USEPA Phase II certified device or pellet stove during non-curtailment periods, nor is registration required for operation of non-District-listed devices during non-curtailment periods. Thus, owners of District-listed devices have the option of registering their devices with the District, and are only required to register if the owners want to operate these devices during curtailment periods.

Maricopa County does not require the registration of approved wood-heating devices in order for these to be used during curtailment periods. (Section P-26.3.C.2) This regulation requires only that such devices operate with no visible emissions during curtailment periods except during 20 minute startup and refueling periods.

As noted in the analysis of Measure 19, Fairbanks required the registration of wood heating devices that qualify as Borough-listed appliances if the owners of such devices desire to operate them during Stage 1 air alert periods. These regulations were removed after passage of the Home Heating Reclamation Act.

EPA commented that the Fairbanks requirements lacked the regular renewal and inspection opportunities to verify proper device operation.

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Analysis

This measure references the same regulations addressed in the Measure 19, therefore the same analysis and conclusions apply; they are restated below.

All three agencies require the registration of permitting of wood heating devices in order to be operated during burning curtailment periods. Alaska's new regulation 18 AAC 50.077(k)(1)(c) requires all wood fired-heating devices to be registered with DEC prior to issuance of any waivers described in the State Air Quality Control plan. The Episode Chapter of that document details the requirement for the issuance of a waiver and the related renewal and inspection requirements separately for non-catalyst equipped and pellet/catalyst equipped devices. All devices require an initial inspection/maintenance verification by a certified chimney sweep. All devices with an emissions rating of >7.5 g/hr are only eligible for 2 annual waivers, lower emitting devices are eligible for longer waiver periods (2, 3 and 5-years). Only devices with an emission rating of <2.0 g/hr are allowed 5-year waivers. These requirements are consistent with those specified in both Missoula City- County and San Joaquin Valley and address EPA's comments.

While Fairbanks currently has natural gas service, it is capacity constrained and will not be in a position to expand service to new customers until 2020 (i.e., after the designated attainment year.[45] Thus, the San Joaquin Valley APCD regulation, which exempts unregistered wood heating devices from curtailment requirements in areas with no natural gas service, is significantly less stringent than the Alaska regulations.

Conclusion

The adoption of the referenced Episode Chapter requirements and state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 22: Require Registration of All Devices

Implementing Jurisdiction(s)

- Missoula City-County MT

Regulation Weblink(s)

- https://www.missoulacounty.us/home/showdocument?id=8452

Background

Missoula City-County requires Installation permits for the installation and use of any new solid fuel burning device in any structure within the Air Stagnation Zone effective July 1, 1986

[45] Appendix A of the Financing Agreement between AIDEA and IGU, December 13, 2017

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(Section 9.202). This regulation limits the eligibility of Installation permits to pellet stoves certified to a $PM_{2.5}$ emission limit of 1.0 gm/hr (Section 9.203).

Fairbanks had prohibited the installation of solid fuel burning devices (SFBD) that are not Borough-listed. Borough-listed devices included USEPA Phase II SFBDs certified to a $PM_{2.5}$ emission limit of 2.5 gm/hr, masonry heaters, cook stoves, and other SFBDs certified to a $PM_{2.5}$ emission limit of 2.5 gm/hr (Section 21.28.020). During Stage 1 Alerts, only Borough-listed devices with Stage 1 waivers issued by the Borough and devices in households with no other adequate source of heat determinations were allowed to continue in operation during burning curtailment periods. These regulations were removed after passage of the Home Heating Reclamation Act.

Analysis

A review of Missoula's regulations found that the Air Stagnation Zone extends roughly 4 miles outside of Missoula City, which is only a small portion of the nonattainment area boundary for the County. As discussed in Measure 19, Alaska's new regulation 18 AAC 50.077(k)(1)(c) requires all wood fired-heating devices to be registered with DEC prior to issuance of any waivers described in the State Air Quality Control plan (i.e., covers the entire nonattainment area). While 18 AAC 50.077 (d), (e), (f), (g) allow the installation of wood fired heating devices meeting an emission limit of 2.0 gm/hr, the Missoula regulation provides no restriction on the emission rate of wood fired heating devices installed outside of the Air Stagnation Zone. The Alaska installation restriction at a higher emission rate covers the entire nonattainment area, while the more restrictive Missoula installation restriction applies to only a small portion of the nonattainment area.

Another consideration is that Measure 22 only applies to new installations and relies on device turnover to be effective. As noted above, the emission rate specified in Alaska's new rule is less stringent than Measure 22, however, 18 AAC 50.077 requires removal or replacement of any wood fired heating device lacking a valid EPA certification under 40 C.F.R. 60.533, or any wood-fired outdoor hydronic heaters, except pellet fueled devices, including those that have a qualifying "white tag" under EPA's Phase 2 voluntary partnership program by December 31, 2024. The date certain removal in combination with the 2.0g/hr limit will result in greater emission reductions in the near term and is therefore more stringent.

Conclusion

The adoption of the referenced state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

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Measure 23: Require Exempt Households to Display a Decal Visible from a Point of Public Access

Implementing Jurisdiction(s)

- Ada County, Idaho

Regulation Weblink(s)

- http://www.sterlingcodifiers.com/codebook/index.php?book_id=447

Background

The Ada County Development Services Department exempts NOASH households and Department-listed low emission wood heating devices from having to cease operation during curtailment periods (Section 5-10-8.A). One of the requirements for a valid exemption is that each affected household display an exemption decal visible from a point of public access.

Previously, the Borough prepared lists of residences registered as NOASH households and those heated with Borough-approved appliances. These lists were used by Borough enforcement staff in the field to identify such residences during Stage 1 Alert periods as exempt from wood burning curtailment requirements. The authority to assemble these lists disappeared with the passage of the Home Heating Reclamation Act

EPA commented that decals could be reflective and would be seen by vehicle headlights, that decals could be used by neighbors to determine who is or is not in compliance and they might be helpful as citizen compliance assistance efforts could supplement the Borough enforcement program.

Analysis

The Ada County measure is intended to facilitate field compliance inspections by highlighting non-exempt residences with visible smoke plumes for enforcement actions. Because of the high prevalence of oil heaters in all Borough residences (79.0%), determination of compliance with curtailment requirements requires a minimum of 20-minute opacity observations – except in the case of NOASH residences - to ascertain oil versus wood fuel sources of visible emissions. Determination of compliance at NOASH residences, which constitute only 2.2% of residences in the nonattainment area, can be ascertained as quickly by examination of a list of NOASH addresses as by observation of a visible decal. Moreover, the Borough prepared lists of residences have been made available to state enforcement staff and are being used to identify registered NOASH residences using tablets with maps noting their locations. The adoption of decals will add no benefit to current enforcement efforts, thus EPA's comments are not relevant.

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Conclusion

The adoption of a visible decal regulation will not provide an emissions reduction benefit during Stage 1 Alerts and, thus, is not technologically feasible. Therefore, this measure is not available for consideration as BACM.

Measure 24: Require Permanent Installed Alternative Heating Method in Rental Units

Implementing Jurisdiction(s)

- Bay Area AQMD; Klamath County; City of Aurora CO

Regulation Weblink(s)

- http://www.baaqmd.gov/~/media/files/planning-and-research/rules-and-regs/reg-06/rg0603.pdf?la=en
- http://www.co.klamath.or.us/EH/Air%20Quality%20&%20Burning/Klamath%20County%20Clean%20Air%20Ordinance.htm
- https://library.municode.com/co/aurora/codes/building_and_zoning?nodeId=BUZOCO_CH146ZO_ART12SURESPUSAC_DIV1GEUS_S146-1204BURE

Background

The Bay Area AQMD requires that all real property offered for lease or rent must have a permanently-installed form of heat that does not burn solid fuel (Section 6-3-305). This requirement becomes effective on November 1, 2018, and is not applicable to properties located in areas not served by natural gas infrastructure.

Klamath County prohibits a solid fuel-fired appliance from being the sole source of heat in any non-owner (tenant) occupied dwelling unit within the county (Section 406.100.3.d).

The City of Aurora, Colorado, also prohibits a solid fuel-fired heating device from being the sole source of heat in any non-owner-occupied dwelling unit (Section 146-1204.C).

Neither Fairbanks nor the state enforce any wood heating device regulations that are specific to rental units. Nor had they adopted any regulations that require the installation of alternative heating systems in either new construction or existing structures.

Analysis

The Bay Area AQMD measure exempts areas not served by natural gas infrastructure from the requirement for rental units to have alternative heating systems. While Fairbanks currently has natural gas service, it is capacity constrained and will not be in a position to expand service to

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new customers until 2020 (i.e., after the designated attainment year).[46] Therefore, this measure would not reduce emissions during curtailment periods if adopted by the state.

Both the Klamath County and City of Aurora measures would, if adopted by Alaska, require the retrofitting of applicable rental units with alternative heating systems and, thus, make such dwellings ineligible for no-other-adequate-source-of-heat (NOASH) determinations by the Borough.

As noted in the introduction, Alaska added a new subsection 50.077(k)(4): Wood-fired heating devices may not be the primary or only heating source:

- New construction, except "dry cabins" on a 2-acre parcel
- For rental units, unless a rental unit prior to the effective date of the regulations and qualifies for a NOASH

This new requirement directly addresses the Klamath County and City of Aurora measures and eliminates the emission benefit of adopting them

Conclusion

The adoption of the referenced state regulation is sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 25: Require Detailed Application or Inspection to Verify Need for No Other Adequate Source of Heat (NOASH) Permit

Implementing Jurisdiction(s)

- Puget Sound Clean Air Agency (PSCAA)

Regulation Weblink(s)

- http://www.pscleanair.org/219/PSCAA-Regulations

Background

The Puget Sound Clean Air Agency (PSCAA) exempts households with no other adequate source of heat (NOASH) from curtailment requirements if the residences or commercial buildings were constructed prior to July 1, 1992 and not substantially remodeled after that date,

[46] AIDEA IGU Financing Agreement op. cit., Appendix A

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and the households have been granted exemptions by the agency (Section 13.05.d.1.a). PSCAA grants NOASH exemption only after receipt and review of a detailed application form.[47]

Fairbanks previously exempted NOASH households from having to cease burning wood during Stage 1 Alerts provided that such households have registered with the Borough. The Borough granted NOASH determinations only after receipt and review of detailed application form that must be notarized before submittal[48]. Regulations mandating these requirements were removed after passage of the Home Heating Reclamation Act.

As noted in Measures 19 and 21, EPA commented that the Fairbanks requirements lacked the regular renewal and inspection opportunities to verify proper device operation.

Analysis

The Episode Chapter of the $PM_{2.5}$ Serious SIP noted in the introduction details Alaska's exception and waiver requirements including:

- Length of waivers based on age and emission rate of the device
- Annual renewals on oldest and highest emission rated devices
- 3rd party inspection of device to verify proper installation required
- 3rd party inspection of maintenance (chimney sweep) required
- Device registration required
- Documentation of dry wood required

Exceptions/Waiver levels are detailed in Tables for Stage 1 and Stage 2 Alerts separately for non-catalyst equipped and pellet/catalyst equipped devices. The structure is intended to provide incentives to upgrade existing devices while at the same time acknowledging the number of devices already changed out as part of the wood stove change out program. A detailed application and verification documentation will be required prior to issuance of any exception or waiver.

These requirements are consistent with PSCAA NOASH curtailment and application requirements and address EPA comments about renewal and inspection opportunities to verify proper device operation.

Conclusion

The adoption of the referenced Episode Chapter requirements are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

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[47] Personal communication between Amy Warren, PSCAA, and Meena Rezaei, Trinity Consultants, on December 15, 2017. Application available for download at: http://www.pscleanair.org/DocumentCenter/View/163; accessed on January 14, 2018.

[48] Application was for download at: http://fnsb.us/transportation/Pages/Change-Out-Program.aspx; accessed on January 14, 2018

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Measure 26: Require Inspection of Device and Installation

Implementing Jurisdiction(s)

- San Joaquin Valley APCD

Regulation Weblink(s)

- https://www.valleyair.org/rules/currntrules/r4901.pdf

Background

San Joaquin Valley APCD requires that applications for wood burning device registration contain certifications by District Registered Wood Burning Heater Professionals verifying that the wood burning heaters meet device eligibility requirements (Section 4901.5.7.3.1.2). This regulation also requires applications for registration renewal to include verifications that the wood burning heaters have been inspected by District Registered Wood Burning Heater Professionals and found to be maintained pursuant to manufacturer specifications (Section 4901.5.8.2.1).

Fairbanks required installations of solid fuel burning appliances in new construction and replacement appliances in subsidized change-outs be performed by Borough-listed vendor/installers using Borough-listed appliances. Regulations mandating these requirements were removed after passage of the Home Heating Reclamation Act.

Analysis

The San Joaquin Valley measure requires that devices applying for registration be inspected by District-registered professional to confirm that the devices are District-listed as low emission units. As noted in Measure 4, recognizing the need for professional installation of wood-fired heating devices and wood-fired retrofit control devices and confirmation of those installations, the state has implemented new regulation subsections 18 AAC 50.077(k)(2) & (3). These subsections directly address those requirements. As noted in Measure 5 the state has implemented new regulations 18 AAC 50.077(k)(2) & (3) requiring the certification of installers by the National Fireplace Institute or Masonry Heaters Association as appropriate. In addition, the Episode Chapter of the $PM_{2.5}$ Serious SIP contains requirements that all NOASH devices must be inspected by certified installers.

Collectively, the new Alaska regulations and Episode Chapter requirements more than satisfy the San Joaquin Valley certification and inspection requirements to ensure that wood burning wood burning heaters meet device eligibility requirements.

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Conclusion

The adoption of the referenced Episode Chapter requirements and state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 27: Require Annual Renewal of Waiver

Implementing Jurisdiction(s)

- Maricopa County

Regulation Weblink(s)

- http://www.maricopa.gov/DocumentCenter/View/5332

Background

Maricopa County AZ requires that residential sole source of heat (NOASH) permits be renewed annually (Ordinance P-26, Section 4.A). This regulation is intended to annually confirm compliance of the permitted household with NOASH requirements and minimize the number of permits issued to non-compliant households. Section 4.A also prohibits the initial issuance of a NOASH permit after December 31, 1995, and allows for annual permit renewal if the initial permit was issued before December 31, 1995 and the household and device continue to meet permit requirements.

Fairbanks required that NOASH households apply and be approved in order to continue burning during curtailment periods. NOASH designations were valid for one year and required renewal to remain valid.[49] The Borough regulations were removed with the passage of the Home Heating Reclamation Act.

Analysis

The exception and renewal requirements for NOASH waivers are specified in the Episode Chapter of the $PM_{2.5}$ Serious SIP. As noted in the Measure 26 analysis, all registration require verification by certified installers. Renewal requirements vary by age, control technology and emission rating. Higher emitting devices older than 10 years are limited to 2 annual renewals. Thus, pre-2010 higher emitting devices are only allowed 2 renewals. Longer renewal periods are allowed for lower emitting devices. Maricopa does not limit the number of renewals for devices installed prior to December 31, 1995. Also, as noted in Measure's 16 and 17 Alaska requires the removal and replacement of devices lacking a valid EPA certification under 40 C.F.R. 60.533, or any wood-fired outdoor hydronic heaters, except pellet fueled devices, including those that have a qualifying "white tag" under EPA's Phase 2 voluntary partnership program by December 31,

[49] Personal communication between Nicholas Czarnecki, FNSB Air Quality Division, and Bob Dulla, Trinity Consultants, on December 19, 2017.

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2024. This requirement ensures rapid turnover of the existing stock of older, higher emitting wood-burning devices over the next 5 years, whereas the Maricopa regulation relies on a much slower turnover of pre 1996 wood-burning devices, while providing no incentive to retire post 1995 wood burning devices. Thus, the older Maricopa NOASH devices can continue to operate into the future, whereas in Alaska those devices (and many more) are required to be removed or replaced by 2024.

Collectively, the new Alaska regulations provide greater emission reductions than would be produced by the adoption of Measure 27.

Conclusion

The adoption of the referenced Episode Chapter requirements and state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 28: Set Income Threshold [for Curtailment Exemption]

Implementing Jurisdiction(s)

- Missoula MT; Maricopa County AZ

Regulation Weblink(s)

- https://www.missoulacounty.us/home/showdocument?id=8452
- http://www.maricopa.gov/DocumentCenter/View/5332

Background

The Missoula City-County Air Pollution Control Program exempts households qualifying for energy assistance from burning curtailment requirements (Section 9.207). Maricopa County grants temporary exemptions from curtailment requirements to households qualifying for energy assistance (Section 4.B).

Fairbanks did not exempt households from curtailment requirements solely on the basis of income, but did allow the granting of sole-source-of-heat exemptions to households in which "economic hardships require the applicant's use of a solid fuel burning appliance" provided that the appliance is Borough-listed, in addition to other requirements. The Borough regulations were removed with the passage of the Home Heating Reclamation Act.

Analysis

The Missoula City-County measure allows low income households to continue burning during curtailment periods. While Alaska will also allow low income households to continue burning during curtailment periods (per the Episode Chapter of the $PM_{2.5}$ Serious SIP), NOASH exceptions/waivers are not exempt from the removal or replacement regulations noted above in

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Measure 27. This means the pool of NOASH waivers will become increasingly cleaner (i.e., lower emitting) over the next 5 years. At this point, Alaska has not established the economic hardship thresholds for NOASH waivers; according to the Episode Chapter they will be defined when the NOASH applications are released.

Overall, the removal or replacement requirements of 18 AAC 70.077(b) will result in greater emission reductions in the near term than any differences in the definition of economic hardship and is therefore more stringent.

Conclusion

The adoption of the referenced Episode Chapter requirements and state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 29: Allow Only NOASH Households to Burn During Curtailment Periods

Implementing Jurisdiction(s)

- Utah Department of Environmental Quality

Regulation Weblink(s)

- https://rules.utah.gov/publicat/code/r307/r307-302.htm

Background

The Utah Department of Environmental Quality exempts only households with no other adequate source of heat (NOASH) from the requirement to cease operation of wood heating devices during curtailment periods in $PM_{2.5}$ nonattainment areas in the state (Section R307-302-3.4). Fairbanks exempted households with NOASH waivers, wood burning appliances with Stage 1 waivers, and wood burning appliances in households affected by power failures from similar curtailment requirements during Stage 1 Alerts. The Borough regulations were removed following the approval of the Home Heating Reclamation Act.

Analysis

Utah calls burn bans when concentrations are forecast to reach or exceed 25 $\mu g/m^3$. Alaska's Episode Chapter of the $PM_{2.5}$ Serious SIP will call Stage 1 Alerts when concentrations are forecast to exceed 20 $\mu g/m^3$. Emission reductions from Alaska's more stringent curtailment thresholds far exceed those that would be produced by adoption Measure 29 for the Fairbanks $PM_{2.5}$ nonattainment area.

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Conclusion

The adoption of the referenced Episode Chapter requirements are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 30: Distribution of Curtailment Information at Time of Sale of Wood-Burning Device

Applicable Jurisdiction(s)

- Bay Area Air Quality Management District (SF Bay Area, CA)

Regulation Weblink(s)

- http://www.baaqmd.gov/~/media/Files/Planning%20and%20Research/Particulate%20Matter/rg0603.ashx

Background

In July 2008, the Board for the Bay Area Air Quality Management District (BAAQMD) adopted amendments to their regulation of wood-burning devices (Regulation 6, Rule 3). One amendment required that "any person offering for sale, selling or providing solid fuel or wood intended for use in a wood-burning device within District boundaries shall…attach a label to each package of solid fuel or wood sold that states the following: 'Use of this and other solid fuels may be restricted at times by law. Please check [Toll-Free Number] or [Web Address] before burning.'"

The presumed intent of this regulation is to reduce $PM_{2.5}$ emissions from wood-burning devices either through reduced sale of the devices or through reduced use of the devices during periods of curtailment.

EPA commented for this and other measures that a finding of insignificant and difficult to quantify emission reductions (i.e., de minimus) is "not a valid rationale for not considering or selecting a control measure or technology".

Analysis

As noted in the analysis of Measure 13, 18 AAC 50.077 (k)(1) requires curtailment information and proper operating instructions to be conveyed at the time of sale of new wood-burning devices by the device vendor or dealer. While this requirement has not been extended to the sale of wood, the Bay Area has not extended this requirement to the sale of wood burning devices. As discussed in Measures 15, 16 and 15 Alaska's new regulations require all noncompliant devices must be removed or replaced by December 31, 2024 and removed or replaced prior to property conveyance and destroyed or rendered inoperable. These requirements will significantly expand the number homes receiving curtailment and directly address EPA's comment. The result is that the adoption of this measure will provide no emissions benefit.

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Conclusion

The adoption of the referenced state regulations are more than sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 31: Require Sale of Only Dry Wood during Late Summer to the End of Winter

Implementing Jurisdiction(s)

- South Coast Air Quality Management District

Regulation Weblink(s)

- https://www.arb.ca.gov/drdb/sc/curhtml/R445.PDF

Background

SCAQMD's Rule 445 limits the sale of commercial firewood to seasoned only firewood from July 1 through the end of February the following year. Seasoned firewood is defined to have a moisture content of 20 percent or less by weight as determined by approved hand held moisture meters or an alternate method defined by the California Air Resources Board. Commercial wood sellers are free to sell both seasoned and non-seasoned firewood during the remaining months of the year. The goal is to restrict the supply of unseasoned wood available for use during winter months.

Fairbanks North Star Borough Code[50] did not allow burning of firewood with a moisture content exceeding 20%. The Code was modified to remove this requirement after voter approval of the Home Heating Reclamation Act.

Alaska regulations[51] require mandatory registration of commercial wood sellers, the use of uniquely numbered three-part moisture disclosure forms, which document the date the wood was cut and findings of moisture measurements of three pieces of wood for each cord sold. The wood seller is required to sign the form, date when it was delivered and obtain signature of the customer purchasing the wood. The wood seller is also required to provide the customer with a copy of the signed disclosure form and submit to the state the department's copy of the completed disclosure form.

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50 http://www.codepublishing.com/AK/FairbanksNorthStarBorough/#!/FNSBC21/FNSBC2128.html#21.28

51 http://burnwise.alaska.gov/requirements.htm

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EPA commented that while the "Borough has SIP approved dry wood requirements that prohibit the burning of wet wood and moisture disclosure requirements by sellers, we believe that a measure limiting the sale of wet wood during the winter months should be further analyzed for BACM (and MSM) consideration."

Analysis

Alaska's 18 AAC 50.076 has been modified to include new subsections that effective October 1, 2021, ensure that all the wood being sold or provided has a moisture content of less than 20%. Subsection (j) includes the following requirements to ensure that wood with a less than 20% moisture content is being sold after the effective date. 18 AAC 50.078(e) would limit non-commercial sellers to selling dry wood. Dry wood is defined as either:

- properly seasoned, split and stored covered for at least 9 months;
- mechanically dried, where the drying process has been inspected and approved by the department to ensure consistency and reliability; or
- harvested from an inspected fire killed source that has been split, stacked, stored and confirmed dry prior to freezing;

Wood sellers are required to test, using a commercially available moisture test meter that the department has approved for accuracy, measure moisture content periodically to verify and ensure stock is dry prior to selling. They are also required to shall document the measured moisture content, and keep a record of the measurements over the seasoning period and sign an affidavit form that the department provides attesting the wood is dry prior to sale.

The new rules recognize that commercial wood sellers will need time to build up the necessary supply of dry wood required to satisfy overall firewood demand. In the intervening period, wood sellers are required to follow the regulations outlined in the background discussion.

These requirements ensure that wood sold in Fairbanks after October 1, 2021 will have a moisture content of less than 20% and will exceed the dry wood requirements mandated in Measure 31; they also address EPA's comments.

Conclusion

The adoption of the referenced state regulations are more than sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 32: Require Dry Wood to be Clearly Labeled to Prohibit Marketing of Non-Dry Wood as Dry Wood

Implementing Jurisdiction(s)

- South Coast Air Quality Management District; San Joaquin Valley Air Pollution Control District; Bay Area Air Quality Management District

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Regulation Weblinks(s)

- https://www.arb.ca.gov/drdb/sc/curhtml/R445.PDF
- http://www.valleyair.org/rules/currntrules/r4901.pdf
- http://www.baaqmd.gov/~/media/files/planning-and-research/rules-and-regs/reg-06/rg0603.pdf?la=en

Background

SCAQMD's Rule 445 limits the sale of commercial firewood to be seasoned only firewood from July 1 through the end of February the following year. Seasoned firewood is defined to have a moisture content 20 percent or less by weight as determined by approved hand held moisture meters or an alternate method defined by the California Air Resources Board. Rule 445 also contains labeling requirements:

> *Effective November 4, 2013, no commercial firewood seller shall sell, offer for sale, or supply wood-based fuel without first attaching a permanently affixed indelible label to each package or providing written notice to each buyer at the time of purchase of bulk firewood that at a minimum, states the following:*
>
> *Use of this and other solid fuel products may be restricted at times by law. Please check (1-877-4NO-BURN) or (www.8774NOBURN.org) before burning.*
>
> San Joaquin Valley AQMD's Rule 4901 has firewood marketing restrictions:
>
> *No person shall sell, offer for sale, or supply any wood which is orally or in writing, advertised, described, or in any way represented to be "seasoned wood" unless the wood has a moisture content of 20 percent or less by weight*
>
> Bay Area AQMD Regulation 6 also has requirements governing the sale of wood:
>
> *Any person offering for sale, selling or providing solid fuel or wood intended for use in a wood-burning device within District boundaries shall:*
>
> *Attach a label to each package of solid fuel or wood sold that states the following:*
>
> *"Use of this and other solid fuels may be restricted at times by law. Please check 1-877-4-NO-BURN or http://www.8774noburn.org/ before burning."*
>
> *If wood is seasoned (not to include manufactured logs), then the label must also state the following:*
>
> *"This wood meets air quality regulations for moisture content to be less than 20 % (percent) by weight for cleaner burning."*

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Analysis

Current Alaska regulations[52] require mandatory registration of commercial wood sellers, the use of uniquely numbered three-part moisture disclosure forms, which document the date the wood was cut and findings of moisture measurements of three pieces of wood for each cord sold. The wood seller is required to sign the form, date when it was delivered and obtain signature of the customer purchasing the wood. The wood seller is also required to provide the customer with a copy of the signed disclosure form and submit to the state the department's copy of the completed disclosure form. The state is assembling the submitted forms into an electronic data base to track the moisture levels and volume of wood sold. Separate requirements address wood measurements and deliveries at temperatures below 32° F. All wood with measurements exceeding 20% is assumed to be wet.

The moisture disclosure forms require the buyer to declare:

> *I understand that starting October 2015, only dry wood may be burned between October 1 and March 31.*

While Alaska does not require firewood to be labeled, it does require buyer to sign a form documenting whether the wood is seasoned or unseasoned.

Current ADEC requirements to have the customer sign a form documenting whether the wood is seasoned or unseasoned ensures that the customer has seen information about the moisture content of the wood being purchased. ADEC's requirement is more stringent than other labeling requirements which the customer may or may not see, let alone acknowledge.

While current ADEC regulations require wood sellers to document and distribute detailed information regarding the moisture content of the wood, there is no regulation limiting or prohibiting the sale wet wood. Wet wood sold and delivered during the winter months, when the average temperature is below freezing, will not dry to below 20% moisture content during that winter season and some fraction of wet wood delivered during the winter months will be burned during that winter resulting in excess emissions. SCAQMD Rule 445 limits the sale of commercial firewood to be seasoned only firewood from July 1 through the end of February the following year, eliminating excess emissions from commercially sold wet wood, and is therefore more stringent than current ADEC regulations.

In addition to the current regulations, which will remain in place, ADEC has proposed to adopt regulations in 18 AAC 50.076(d) that require commercial wood sellers to sell only dry wood year round after October 1, 2021; 18 AAC 50.078(e) would limit non-commercial sellers to selling dry wood. Dry wood is defined as below 20% moisture content. Monitoring, recordkeeping, and reporting requirements are also included in the proposed regulations to ensure compliance with the 20% moisture standard. The adoption of proposed modifications to regulation 18 AAC 50.076 are sufficient to meet BACM requirements for this control measure.

[52] https://dec.alaska.gov/air/anpms/sip/18aac50-reference-materials/

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Conclusion

The adoption of the referenced state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 33: Burn Permits Required

Implementing Jurisdictions

- Klamath County, Feather River AQMD

Regulation Weblink(s)

- http://www.co.klamath.or.us/EH/Air%20Quality%20&%20Burning/Klamath%20County%20Clean%20Air%20Ordinance.htm
- https://www.arb.ca.gov/drdb/fr/curhtml/r3-17.pdf

Background

Klamath County OR requires persons conducting open burning to adhere to all local and state fire protection rules and restrictions, including possession of any required local burn permit issued by a local fire agency (Section 406.100.4.c). This regulation also prohibits open burning during burning curtailment periods (Section 406.100.4.a).

Feather River Air Quality Management District CA requires valid burn permits issued by the agency for all open burning with the exception of the burning of vegetation at one- or two-family residences on parcels less than two acres in size provided that requirements of fire protection services are met. (Section 2.0.H) Burn permits are invalid on No Burn Days declared by the agency. (Section 2.0.J.6)

The Alaska Department of Environmental Conservation requires written approval from the agency for the open burning of woody debris removed from sites greater than 40 acres in size on land being cleared for farming or development, prescribed burning of sites greater than 40 acres in size by land management agencies, fire fighter training burns, and the burning of materials that produce black smoke (Section 18 AAC 50.065.(g), (h), (i)). Department regulations also prohibit open burning in $PM_{2.5}$ nonattainment areas between November 1 and March 31 (Section 18 AAC 50.065.f). The definition of open burning in DEC regulations (Section 18 AAC 50.990.65) does not include campfires or ceremonial fires. The only use of such fires during the winter heating season in Fairbanks is for a handful of very small ice fishing huts for warming purposes. Ice fishing ceases when ambient temperatures reach subzero levels that are typical of Stage 1 alert periods.[53]

[53] Personal communication between Nicholas Czarnecki, FNSB Air Quality Division, and Bob Dulla, Trinity Consultants, on January 25, 2018.

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EPA commented that Stage 1 Alerts were referred to multiple times and asked that the analysis clarify whether the measure applied during all stages of the Alert and the level of control with each stage. EPA also commented that multiple measures "identify that recreational fires have been exempted from existing regulations. Small unregulated recreational fires, bonfires, fire pits, and warming fires have the potential to contribute emissions during a curtailment period. The FNSB and ADEC regulations should be re-evaluated for removing this exclusion."

Analysis

Although the requirements to possess burn permits for open burning are more restrictive in Klamath County and Feather River AQMD, such permit programs – if adopted by Alaska DEC – would not reduce $PM_{2.5}$ emissions during Stage 1 Alerts as existing DEC regulations ban open burning both during the winter heating season and address EPA's concern about their application to different Alert stages. The removal of the ceremonial fire exemption will have no measureable emissions benefit in the Fairbanks nonattainment area, thus EPA's comments are not relevant. EPA also commented that Klamath County and Feather River measures were more stringent than the Fairbanks Code requirements. As noted earlier, those regulations were removed from Borough Code following voter approval of the Home Heating Reclamation Act, thus EPA's comment related to Borough stringency is no longer relevant.

Conclusion

The burn permit measures adopted by Klamath County and Feather River AQMD are less stringent than the Alaska DEC ban on open burning during the wood heating season. Thus, these measures are technologically infeasible not eligible for consideration as BACM.

Measure 34: Prohibit Burn Barrels and Other Outdoor Equipment

Implementing Jurisdiction(s)

- Klamath County

Regulation Weblink(s)

- http://www.co.klamath.or.us/EH/Air%20Quality%20&%20Burning/Klamath%20County%20Clean%20Air%20Ordinance.htm

Background

Klamath County OR prohibits the use of burn barrels and other outdoor burning devices. (Section 406.150.2.c)

Alaska DEC prohibits the use of burn barrels and non-permitted incinerators during the wood heating season from November 1 through March 31. (18 AAC 50.065.f)

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EPA commented that "Measure 34 is less stringent in Fairbanks than in Klamath County. Uncertainty in weather forecasting means that Stage 1 alerts are not called correctly all the time, and not everyone is aware of when an alert is in effect. It is much simpler and less prone to error to prohibit burn barrels and outdoor burning devices entirely."

Analysis

Although Klamath County bans use of burn barrels and other outdoor burning devices throughout the year, the Alaska DEC ban on the use of burn barrels and non permitted incinerators during the wood heating season from November 1 through March 31 in the Fairbanks nonattainment area results in the same level of emission control from these devices during burning curtailment periods. These requirement directly address EPA's concerns.

Conclusion

This measure as adopted by Klamath County is not more stringent than the corresponding requirement in existing Alaska DEC regulations and, thus, is technologically infeasible and not eligible for consideration as BACM.

Measure 35: Restrict Burning During Air Pollution Events

Implementing Jurisdiction(s)

- Klamath County; Ada County

Regulation Weblink(s)

- http://www.co.klamath.or.us/EH/Air%20Quality%20&%20Burning/Klamath%20County%20Clean%20Air%20Ordinance.htm
- http://www.sterlingcodifiers.com/codebook/index.php?book_id=447

Background

Klamath County OR prohibits open burning during burning curtailment periods (Section 406.100.4.a). Oregon Department of Environmental Quality regulations exempt recreational fires and ceremonial fires from open burning requirements (Section 340-264-0040).

Ada County ID prohibits the open burning of refuse or solid fuel during declared air quality alerts (Section 5-10-8.C). County regulations also exempt recreational or warming fires from open burning restrictions provided that such fires do not violate air pollution alerts (Section 5-2-7-2.D).

Alaska Department of Environmental Conservation prohibits open burning in $PM_{2.5}$ nonattainment areas between November 1 and March 31 (Section 18 AAC 50.065.f). These regulations also exempt ceremonial fires from open burning restrictions (Section 18 AAC 50.990.65.B).

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EPA commented that multiple measures "identify that recreational fires have been exempted from existing regulations. Small unregulated recreational fires, bonfires, fire pits, and warming fires have the potential to contribute emissions during a curtailment period. The FNSB and ADEC regulations should be re-evaluated for removing this exclusion."

Analysis

The measures adopted by Klamath County and Ada County contain the same exemptions from open burning restrictions for recreational fires as are contained in the Alaska regulations. Exempt fires are rarely ignited in Fairbanks when ambient temperatures reach subzero levels that are typical during Stage 1 Alert periods.[54] The removal of the ceremonial fire exemption will have no measureable emissions benefit in the Fairbanks nonattainment area, thus EPA's comments are not relevant.

Conclusion

These measures as adopted by Klamath County and by Ada County are not more stringent than the corresponding requirements in existing Alaska DEC regulations and, thus, are not technologically infeasible and not eligible for consideration as BACM.

Measure 36: Prohibit Residential Open Burning

Implementing Jurisdiction(s)

- South Coast AQMD

Regulation Weblink(s)

- http://www.aqmd.gov/docs/default-source/rule-book/rule-iv/rule-444.pdf
- http://www.aqmd.gov/docs/default-source/rule-book/rule-iv/rule-445.pdf?sfvrsn=4

Background

The South Coast Air Quality Management District prohibits residential open burning within its jurisdiction (Section 444.d.3.A). This rule also exempts recreational fires and ceremonial fires from the prohibition on residential open burning (Section 444.h.6.A). South Coast AQMD regulations also prohibit the operation of wood burning devices during mandatory winter burning curtailment periods (Section 445.e) but exempts ceremonial fires, as exempted under Rule 444, from curtailment requirements (Section 445.f.7.E).

[54] Personal communication between Nicholas Czarnecki, FNSB Air Quality Division, and Bob Dulla, Trinity Consultants, on January 25, 2018.

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Alaska Department of Environmental Conservation prohibits open burning in $PM_{2.5}$ nonattainment areas between November 1 and March 31 (Section 18 AAC 50.065.f). These regulations also exempt ceremonial fires from open burning restrictions (Section 18 AAC 50.990.65.B).

EPA commented that multiple measures "identify that recreational fires have been exempted from existing regulations. Small unregulated recreational fires, bonfires, fire pits, and warming fires have the potential to contribute emissions during a curtailment period. The FNSB and ADEC regulations should be re-evaluated for removing this exclusion."

Analysis

The South Coast AQMD measure authorizes ceremonial fires during a mandatory winter burning curtailment period. However, the South Coast AQMD regulations do not contain definitions of either "ceremonial fires" or "recreational fires". Although the Alaska DEC exemptions from open burning for campfires and ceremonial fires is no less restrictive than the South Coast exemption for ceremonial fires, campfires or ceremonial fires are rarely ignited during Stage 1 Alert periods in Fairbanks because of the ambient subzero temperatures that typically occur during these periods. The removal of the ceremonial fire exemption will have no measureable emissions benefit in the Fairbanks nonattainment area, thus EPA's comments are not relevant.

Conclusion

This measure as adopted by South Coast AQMD is not more stringent than the corresponding requirements in existing Alaska DEC regulations and, thus, is not technologically infeasible and not eligible for consideration as BACM.

Measure 37: Periodic Burn Windows

Implementing Jurisdictions

- Klamath County

Regulation Weblink(s)

- http://www.co.klamath.or.us/EH/Air%20Quality%20&%20Burning/Klamath%20County%20Clean%20Air%20Ordinance.htm
- https://secure.sos.state.or.us/oard/viewSingleRule.action?ruleVrsnRsn=76168

Background

Klamath County OR authorizes the Environmental Health Division Manager, in consultation with specified county, city, and local fire officials, to limit residential open burning to two 15-day periods each year (Section 406.150.2.a). If declared, one window must occur in the spring and one in the fall. Open burning is prohibited during burning curtailment periods (Section 406.100.4.1). The definition of residential open burning in Oregon Department of

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Environmental Quality regulations excludes recreational fires and ceremonial fires (Section 340 264-0040.1).

Alaska Department of Environmental Conservation prohibits open burning in $PM_{2.5}$ nonattainment areas between November 1 and March 31 (Section 18 AAC 50.065.f). These regulations also exempt ceremonial fires from open burning restrictions (Section 18 AAC 50.990.65.B).

EPA commented that multiple measures "identify that recreational fires have been exempted from existing regulations. Small unregulated recreational fires, bonfires, fire pits, and warming fires have the potential to contribute emissions during a curtailment period. The FNSB and ADEC regulations should be re-evaluated for removing this exclusion."

Analysis

The Klamath County and Oregon DEQ regulations authorize the setting of residential open burning windows to limit the days each year when such open burning may be conducted, but the requirement limiting these to the spring and fall means that none of these windows will occur during the winter heating season. Regardless, Klamath County prohibits residential open burning during burning curtailment periods. The Alaska DEC regulations ban all residential open burning during the winter heating season in the Fairbanks $PM_{2.5}$ nonattainment area. Both Oregon and FNSB regulations exempt recreational and ceremonial fires from residential open burning prohibitions. The removal of the ceremonial fire exemption will have no measureable emissions benefit in the Fairbanks nonattainment area, thus EPA's comments are not relevant.

Conclusion

This measure as adopted by Klamath County is not more stringent than the corresponding requirements in existing Alaska DEC regulations and, thus, is not technologically feasible and not eligible for consideration as BACM.

Measure 38: Ambient $PM_{2.5}$ Curtailment Threshold (1-Hr Average)

Applicable Jurisdiction(s)

- Cache Valley and Cities, Idaho

Regulation Weblink(s)

- https://adminrules.idaho.gov/rules/2014/58/0101.pdf

Background

Many jurisdictions with wood smoke control programs have adopted specific air quality thresholds for triggering burn bans, or curtailments, during which certain activities that produce $PM_{2.5}$ emissions are prohibited, or at least severely restricted. The Idaho Department of

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Environmental Quality (IDEQ) is the only regulatory agency found to trigger curtailment periods on the basis of ambient $PM_{2.5}$ levels measured over 1-hour averaging periods. Most other air quality agencies with burn ban authority base curtailment decisions on $PM_{2.5}$ levels averaged over 12- to 24-hour periods. Most importantly, this local 1-hour threshold in the Cache Valley and cities of Idaho applies only to curtailment or cessation of open burning, not wood-based residential space heating.

Under the Idaho Administrative Code, IDEQ has the authority to issue a Stage 1 Forecast and Caution when "particulate concentrations reach, or are forecasted to reach, and persist, at or above the levels listed" in the table below.[55] Under the Stage 1 Air Pollution Forecast and Caution, "there shall be no new ignition of open burning of any kind." In addition, the director of the IDEQ may request the cessation of open burning. (Again, this Stage 1 Forecast and Caution applies only to open burning and does not apply to residential wood heating.)

Table 8. Stage 1 Forecast Levels

Pollutant	Standard
$PM_{2.5}$	80 µg/m^3 1 hour average
$PM_{2.5}$	50 µg/m^3 24 hour average
PM_{10}	385 µg/m^3 1 hour average
PM_{10}	150 µg/m^3 24 hour average

This authority is also found in IDEQ's Air Pollution Emergency Rule.[56]

Analysis

Discussions with staff members of IDEQ[57] and the Utah Department of Environmental Quality (UDEQ)[58] found the jurisdictions share a common $PM_{2.5}$ nonattainment area and thus coordinate regulations on many air quality issues; they indicated that the 1-hour standard is outdated and no longer used. Staff members from UDEQ indicated that they had no regulations based upon 1-hour standards and that all regulations were based upon 24-hour averaging periods. The $PM_{2.5}$ thresholds, for example, have never been updated to correlate to the current NAAQS standards. Staff from IDEQ instead use a 24-hour concentration of 30 µg/m^3 as a curtailment threshold and are considering a lowering of their 24-hour standard if that proposed by Utah is accepted and required by EPA.

[55] Idaho Department of Environmental Quality, Idaho Administrative Code, Rules for the Control of Air Pollution in Idaho, IDAPA 58.01.01, available at https://adminrules.idaho.gov/rules/2014/58/0101.pdf; Accessed October/10/2017.
[56] https://www.deq.idaho.gov/media/344469-emerg_rule_fs.pdf; Accessed October 10, 2017.
[57] Personal communication with Melissa Gibbs, Idaho Department of Environmental Quality, October 5, 2017.
[58] Personal communications with Bo Call, Utah Department of Environmental Quality, October 4, 2017; Personal communication with Joel Karmazyn, October 5, 2017.

Moreover, the Alaska Department of Environmental Conservation (ADEC) already has a state regulation in place[59] that prohibits open burning in the Fairbanks $PM_{2.5}$ nonattainment area between November 1 and March 31, the period that essentially corresponds to historical $PM_{2.5}$ violations.

The 1-hour concentration-based threshold adopted in Idaho applies to curtailment/cessation of open burning, not residential space heating. ADEC's existing regulation (18 AAC 50.065) prohibits open burning in the nonattainment area during the winter season. Thus, implementation of the Idaho 1-hour average threshold for curtailing open burning would have no impact on wood smoke emissions during the wintertime nonattainment season in Fairbanks, and is not applicable to curtailment or restrictions on residential space heating. In summary, ADEC's ban on open burning during the winter season is more stringent than this measure.

Conclusion

The adoption of this measure will provide no emissions benefit in the Fairbanks nonattainment area, therefore the measure is technologically infeasible and not eligible for consideration as BACM.

Measure 39: Use of AQI as Basis for Curtailment Threshold

Applicable Jurisdiction(s)

- Cache Valley and Cities, Idaho

Regulation Weblink(s)

- http://www.deq.idaho.gov/media/930593-cache-valley-pm2-5-sip-appendices-1212.pdf

Background

Franklin County and the Cache Valley cities in Idaho use a $PM_{2.5}$ Air Quality Index (AQI) level of 75 as the threshold for declaring a burn ban (curtailment) for residential wood stoves. This level is equivalent to an ambient concentration of 23.5 $\mu g/m^3$.[60] Most other jurisdictions that regulate residential wood burning specify $PM_{2.5}$ concentration-based thresholds for a curtailment declaration (typically in the 25-35 $\mu g/m^3$ range) rather than specifying AQI levels.

The Cache Valley attainment plan submitted to the EPA by the Idaho Department of Environmental Quality states, in many locations, that burning is prohibited when the AQI for the

[59] 18 AAC 50.065
[60] https://airnow.gov/index.cfm?action=airnow.calculator

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region reaches 75 or higher.[61] The restriction applies, in one section, to "all wood burning, including but not limited to, within a solid fuel heating appliance designed for wood fuel (commonly known as a 'wood stove') or open fireplace" and in another to "any open burning of any kind."

Analysis

Personal communication with Idaho DEQ[62] staff suggested that the adoption of an AQI-based threshold rather than a $PM_{2.5}$ concentration-based threshold was motivated solely by the desire to avoid having to rewrite regulations to modify the "trigger level" when EPA revised the NAAQS. The AQI is itself a function of the NAAQS standard and so, when the standard is reduced by EPA, the concentration equivalent to an AQI of 75 – or any other measure of AQI – would correspondingly be reduced as well.[63] Thus the jurisdiction would not need to modify its regulation in response to a NAAQS change. The staff member indicated that no documentation existed to suggest whether the use of AQI- or concentration-based thresholds would be more effective at reducing emissions.

Further communication with the Idaho DEQ suggested that the use of an AQI- rather than a concentration-based threshold did not likely affect the compliance rate of affected woodstoves and that the news release containing the curtailment order typically did not even mention the criteria used to initiate the curtailment.

Conclusion

Given the equivalence between AQI and $PM_{2.5}$ concentrations thresholds the question of technological feasibility depends on the stringency of adopted AQI thresholds; therefore, this measure provides no emission benefit and is therefore technologically infeasible and not eligible for consideration as BACM.

Measure 40: Single Stage Curtailment

Applicable Jurisdiction(s)

- Bay Area Air Quality Management District (SF Bay Area, CA)

[61] Idaho Department of Environmental Quality, Cache Valley Idaho $PM_{2.5}$ Nonattainment Area SIP, Appendix E: Reasonably Available Control Methods, 2006, available at http://www.deq.idaho.gov/media/930593-cache-valley-pm2-5-sip-appendices-1212.pdf; Accessed October 10, 2017.
[62] Personal communication with Melissa Gibbs, Idaho Department of Environmental Quality, October 5, 2017.
[63] Calculator for AQI maintained by EPA at https://airnow.gov/index.cfm?action=airnow.calculator

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Regulation Weblink(s)

- http://www.baaqmd.gov/~/media/files/planning-and-research/rules-and-regs/reg-06/rg0603.pdf?la=en

Background

The Fairbanks Borough had two stages for the curtailment of wood stove activity in response to a decrease in air quality. Under Stage 1, the use of non-certified devices is banned within the nonattainment region. Under Stage 2, when elevated from Stage 1, the use of all wood-burning devices is banned within the nonattainment region.[64] Thus, those with EPA-certified burning devices were allowed to use them during Stage 1 but not during Stage 2. Borough regulations were removed following voter approval of the Home Heating Reclamation Act.

Other jurisdictions have mandatory burn bans, or curtailment periods, that consist of only one phase. Once the period has been initiated, activity is banned for all burning devices. One such jurisdiction is the Bay Area Air Quality Management District (BAAQMD). The initial regulation, adopted in 2008, makes mention of only one stage of curtailment. Upon proposal of the regulation for consideration by the BAAQMD Board, BAAQMD staff only estimated the overall emission reduction that could be anticipated from the mandatory curtailment provision; they made no comparison of those emission reductions to those that could be anticipated with a two-stage curtailment program.[65]

EPA commented that "Measure 40 needs to include a discussion of all the areas listed on page 22. In addition, if a date certain measure or if Measure 29 were instituted, Measure 40 would essentially be achieved." (emphasis added)

Analysis

Other jurisdictions, however, have actually compared the single-stage and double-stage options. For example, the Sacramento Metropolitan Air Quality Management District, in 2009, conducted a direct comparison of both options. Staff evaluated the benefits of lowering stage thresholds to strengthen Rule 421. Two options were considered:

Option A – change to a single-stage program and eliminate the exemption for EPA certified wood stoves and pellet stoves. And, set the No Burn Threshold to 30 $\mu g/m^3$ and either maintain the voluntary threshold at 20 $\mu g/m^3$ or reduce it to 20 $\mu g/m^3$.

[64] Fairbanks North Star Borough Air Quality Division, 2017, available at http://fnsb.us/transportation/AQDocs/AQ%20resource%20guide%20April%202017.pdf; accessed October 25, 2017.

[65] BAAQMD, 2008, Staff Report: Proposed New Regulation 6: Particulate Matter, Rule 3: Wood-burning Devices Amendments to Regulation 1: General Provisions and Definitions, and Regulation 5: Open Burning, received from personal correspondence with Marcy Hiratzka, BAAQMD, October 25, 2017.

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Option B – reduce the Stage 1 threshold to 25 µg/m^3 and the Stage 2 threshold to 30 µg/m^3 to be consistent with San Joaquin Valley No Burn Threshold. Also reduce the voluntary threshold to 20 µg/m^3.

The analysis led staff to recommend Option A. Public comment about the reduced incentive to convert to cleaner burning devices however caused staff to change their recommendation to maintain a two Stage program with reduced thresholds: Stage 1 lowered from 35 to 31 µg/m^3 and a Stage 2 threshold lowered from 40 to 35 µg/m^3. The staff report noted the following:

> *However, many comments at the workshop expressed concern that eliminating a two-stage program, with its exemption for EPA certified devices and pellet stoves on Stage 1 days, would reduce the incentive for people to switch to cleaner devices and also be unfair to those who have already invested in cleaner devices.*[66]

While the analysis demonstrated an increase in the number of curtailment days at lower thresholds, the impact on the estimate of avoided exceedance days did not account for the reduced incentive to invest in cleaner devices. It also did not account for the impact of the increased # of curtailment days on the compliance rate (it was assumed to be unchanged).

As discussed earlier Alaska has added several new regulations which directly address the measure and EPA's comments. First in Measure 16, the analysis noted that Alaska's new regulation 18 AAC 50.077(b) specifies that a person may not operate, install, reinstall, sell, lease, distribute, or convey wood-fired heating devices that lack a valid EPA certification under 40 C.F.R. 60.533 or any wood-fired outdoor hydronic heaters, except pellet fueled devices, including those that have a qualifying "white tag" under EPA's Phase 2 voluntary partnership program. All noncompliant devices must be removed or replaced by December 31, 2024, removed or replaced prior to property conveyance and destroyed or rendered inoperable.

Second, Measure 29's analysis noted, Utah calls burn bans when concentrations are forecast to reach or exceed 25 µg/m^3. Alaska's Episode Chapter of the $PM_{2.5}$ Serious SIP will call Stage 1 Alerts when concentrations are forecast to exceed 20 µg/m^3. Emission reductions from Alaska's more stringent curtailment thresholds far exceed those that would be produced by adoption Measure 29 for the Fairbanks $PM_{2.5}$ nonattainment area, therefore satisfying EPA's comment.

Collectively, these new regulations which the state is now enforcing under the Episode Chapter of the $PM_{2.5}$ Serious SIP provide significantly greater emission reductions than the single stage requirements of this measure.

[66] Sacramento Metropolitan Air Quality Management District, 2009, Staff Report: Rule 421, Mandatory Episodic Curtailment of Wood and Other Solid Fuel Burning, available at http://www.airquality.org/ProgramCoordination/Documents/Rule421%20StaffReport%20082409.pdf; accessed October 25, 2017.

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Conclusion

The adoption of the referenced Episode Chapter requirements are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 41: Special Needs Permit

Implementing Jurisdiction(s)

- Missoula City-County MT

Regulation Weblink(s)

- https://www.missoulacounty.us/home/showdocument?id=8452

Background

The Missoula City-County Air Pollution Control Program exempts households with valid Special Needs Permits from curtailment burning bans (Section 9.207). To qualify for a Special Needs Permit, an applicant must demonstrate an economic need to burn solid fuel for space heating purposes by qualifying for energy assistance according to economic guidelines of the federal Low-Income Energy Assistance Program. Special Need Permits are valid for one year and may be renewed if the applicant continues to meet the applicable heating need and qualifies for energy assistance.

Alaska DEC regulations authorize the Department to grant a temporary waiver allowing the burning of solid fuel for space heating purposes during an air quality episode only if opacity limits are met and the owner or operator obtains a temporary waiver based:

- financial hardship as demonstrated by documentation provided to the Department;
- technical feasibility and device design information;
- potential impact to sensitive populations;
- mitigation measures implemented by the owner; and
- the contribution of the device to the exceedance.

Analysis

Missoula City-County automatically grants one-year exemptions to owners or operators who satisfy specific hardship qualifications. Alaska DEC regulations give the Department discretion as to the granting of a temporary waiver based on more criteria than solely economic hardship.

Conclusion

As the Alaska DEC temporary waiver is discretionary and the Missoula City-County exemption is ministerial, the Missoula City-County measure is not more restrictive than the corresponding

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regulation currently enforced by Alaska DEC and, thus, is technologically infeasible and not a candidate for consideration as BACM.

Measure 42: Burn Down Period

Implementing Jurisdiction(s)

- Puget Sound CAA; Maricopa County

Regulation Weblink(s)

- http://www.pscleanair.org/219/PSCAA-Regulations
- http://www.maricopa.gov/DocumentCenter/View/5332

Background

The Puget Sound Clean Air Agency requires solid fuel burning devices to be shut down when a First Stage of Impaired Air Quality (curtailment) has been declared (Sections 13.05.a.1 and 13.05.d.1.a). Certain categories of devices, such as pellet stoves, Oregon DEQ-certified Phase 2 devices, Washington DOE-certified devices, and devices in households with no other adequate source of heat, are allowed to continue operating during a curtailment period provided that all applicable registration requirements are met. When a curtailment period is declared, fuel to non-exempt devices must be withheld, and combustion in these devices – as evidenced by visible smoke from a chimney – must cease within three hours after the declaration is issued (Section 13.05.b).

Maricopa County defines "Burn-Down Period" as "That period of time, not to exceed three hours after declaring a restricted-burn period, required for the cessation of combustion within any residential wood-burning device, outdoor fire pit, wood-burning chimney, or similar outdoor fire by withholding fuel or by modifying the air-to-fuel-ratio" (Section P-26.2.D). This regulation also stays enforcement of visible emission limits for three hours after a curtailment declaration is issued (Section P-26.3.D.4).

Fairbanks' regulations did not specifically exempt smoke emitted during burn down periods from compliance with opacity limits, but do exempt visible emissions from a chimney in excess of the opacity standard for a period not to exceed 30 minutes during a curtailment period before citing unauthorized wood heating devices for unlawful operation during a curtailment period. Those regulations were removed following the passage of the Home Heating Reclamation Act.

Analysis

Alaska added a subsection 18 AAC 70.075(e)(3) "that fuel to non-exempt devices must be withheld, and combustion in these devices – as evidenced by visible smoke from a chimney – must cease within three hours after announcement."

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The addition of this subsection matches the burn down requirements set in Measure 42. Therefore, the adoption of this measure will provide no emission benefits in Fairbanks.

Conclusion

The adoption of the referenced state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 43: Exempt Ceremonial or Religious Fires

Implementing Jurisdictions

- South Coast AQMD

Regulation Weblink(s)

- http://www.aqmd.gov/docs/default-source/rule-book/rule-iv/rule-444.pdf
- http://www.aqmd.gov/docs/default-source/rule-book/rule-iv/rule-445.pdf?sfvrsn=4

Background

The South Coast Air Quality Management District prohibits residential open burning within its jurisdiction (Section 444.d.3.A). This rule also exempts recreational fires and ceremonial fires from the prohibition on residential open burning (Section 444.h.6.A). South Coast AQMD regulations also prohibit the operation of wood burning devices during mandatory winter burning curtailment periods (Section 445.e) but exempts ceremonial fires, as exempted under Rule 444, from curtailment requirements (Section 445.f.7.E).

Alaska Department of Environmental Conservation prohibits open burning in $PM_{2.5}$ nonattainment areas between November 1 and March 31 (18 AAC 50.065(f)). These regulations also exempt ceremonial fires from open burning restrictions (18 AAC 50.990(65)(B)).

EPA commented that multiple measures "identify that recreational fires have been exempted from existing regulations. Small unregulated recreational fires, bonfires, fire pits, and warming fires have the potential to contribute emissions during a curtailment period. The FNSB and ADEC regulations should be re-evaluated for removing this exclusion."

Analysis

The South Coast AQMD measure authorizes ceremonial fires during a mandatory winter burning curtailment period. However, the South Coast AQMD regulations do not contain definitions of either "ceremonial fires" or "recreational fires". Alaska DEC regulations exempt campfires and ceremonial fires from the ban on open burning during Stage 1 Alerts. The adoption by Alaska DEC of the South Coast AQMD exemption granted to ceremonial or religious fires would not reduce emissions during Stage 1 Alerts since Alaska DEC currently exempts campfires and

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recreational fires from burning curtailment requirements. The removal of the ceremonial fire exemption will have no measureable emissions benefit in the Fairbanks nonattainment area, thus EPA's comments are not relevant.

Conclusion

This measure as adopted by South Coast AQMD is not more stringent than the corresponding requirements in existing Alaska DEC regulations and, thus, is not technologically feasible and not eligible for consideration as BACM.

Measure 44: Alternative Heating Appliance Failure

Implementing Jurisdiction(s)

- Missoula City-County, Maricopa County, Klamath County

Regulation Weblink(s)

- https://www.missoulacounty.us/home/showdocument?id=8452
- http://www.maricopa.gov/DocumentCenter/View/5332
- http://www.co.klamath.or.us/EH/Air%20Quality%20&%20Burning/Klamath%20County%20Clean%20Air%20Ordinance.htm

Background

The Missoula City-County Air Pollution Control Program allows residents to apply for a temporary sole source permit in an emergency situation where the resident demonstrates his furnace or central heating system is inoperable other than through his own actions, where the furnace or central heating system is involuntarily disconnected from its energy source by a utility or fuel supplies, or where the normal fuel or energy source is unavailable for any reason (Section 9.208.2). The temporary sole source permit allows a household to continue burning wood for heating purposes during burning curtailment periods (Section 9.208.1). Conditions related to public health endangerment and economic hardship also apply to the approval of a temporary sole source permit, and the permit is valid for a period determined by the agency but may not exceed one year (Sections 9.208.3 through 9.208.7).

Maricopa County authorizes the agency director to issue emergency exemptions from curtailment requirements to households demonstrating that the alternative heating system is inoperable for reasons other than the occupants' own actions or demonstrating that the heating system has been involuntarily disconnected by a utility company or fuel provider (Section P-26.4.C). An emergency exemption is valid only for the period determined by the agency director, but shall not exceed one year from the date of issuance.

Klamath County authorizes the Environmental Health Division to issue Emergency Condition exemptions from burning curtailment requirements when utility suppliers declare energy shortages, electric power outages occur, interruptions of natural gas supply occur, or when there

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is an immediate need to operate a wood heating device to protect family or individual health and safety (Section 406.150.1.f).

Alaska DEC would only exempt households from curtailment if the primary heating system fails or is unavailable.

Analysis

The use of wood heating devices during periods of alternative heating appliance failure in Missoula City-County, Maricopa County, and Klamath County is allowed under several failure modes. Alaska DEC would only allow exemptions if the primary heating system fails.

Conclusion

This measure is not more stringent than the corresponding requirement in the existing Alaska DEC regulations and, thus, is not technologically feasible and not eligible for consideration as BACM.

Measure 45: Elevation Exemption from Wood Burning Curtailments

Implementing Jurisdiction(s)

- South Coast Air Quality Management District; Utah Department of Environmental Quality

Regulation Weblink(s)

- http://www.aqmd.gov/docs/default-source/rule-book/rule-iv/rule-444.pdf
- https://rules.utah.gov/publicat/code/r307/r307-302.htm#T3

Background

In the South Coast, Mandatory Winter Burning Curtailment is defined to occur:

> *..during the consecutive months of November through February where the burning of solid fuels is restricted for portions of the South Coast Air Basin at elevations below 3,000 feet above Mean Sea Level (MSL) based on air quality criteria contained in AQMD Rule 445 (Wood Burning Devices).* (emphasis added)

Utah's Rule 307 (Solid Fuel Burning) provides exemption from wood burning restrictions for sources located at elevations above 7,000 feet.

Alaska DEC does not provide an elevation exemption from burning curtailment requirements.

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Analysis

A review of topographical maps found that no portion of the Fairbanks $PM_{2.5}$ nonattainment area is at an elevation above 3,000 feet MSL. This finding was confirmed by the Borough's Air Quality Division. The existing Alaska DEC air quality regulations do not provide an elevation exemption from burning curtailment requirements.

Conclusion

This measure is less restrictive than the corresponding requirement currently enforced by Alaska DEC and thus is not technologically feasible and not eligible for consideration as BACM.

Measure 46: Lack of Electrical or Natural Gas Service Availability

Implementing Jurisdiction(s)

- South Coast Air Quality Management District; San Joaquin Valley Air Pollution Control District

Regulation Weblink(s)

- http://www.aqmd.gov/docs/default-source/rule-book/rule-iv/rule-445.pdf?sfvrsn=4
- https://www.valleyair.org/rules/currntrules/r4901.pdf

Background

The South Coast Air Quality Management District exempts wood heating devices from burning curtailment requirements in households where there is no existing infrastructure for natural gas service within 150 feet of the property line (Section 445.f.7.C).

San Joaquin Valley Air Pollution Control District exempts wood burning fireplaces and wood burning heaters from burning curtailment requirements in areas where natural gas service is not available (Section 4901.5.6.3.1).

Fairbanks did not exempt households from curtailment requirements due to a lack of natural gas service but it did allow all wood heating devices affected by an electrical power failure to be used for space heating purposes during Stage 1 alerts. Fairbanks curtailment requirements were removed with the passage of the Home Heating Reclamation Act.

EPA commented "The current Fairbanks curtailment exemption "These restrictions shall not apply during a power failure." should be reviewed to clarify that it only applies to homes reliant on electricity for heating. As currently written, it appears overly broad."

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Analysis

As discussed in Measure 8, Fairbanks currently has natural gas service, however it is capacity constrained and will not be in a position to expand service to new customers until 2020 (i.e., after the designated attainment year).[67] Thus, the San Joaquin Valley APCD regulation, which exempts unregistered wood heating devices from curtailment requirements in areas with no natural gas service, is significantly less stringent than the Alaska regulations.

With regard to EPA's comment about restrictions during power failure, the Episode Chapter of the $PM_{2.5}$ Serious SIP, provides an exception for cases where electrical power outages prevent use of alternative heating devices. This requirement is not overly broad as electricity is required to power all alternative (i.e., non-wood) heating devices, since they require pumps, fans, resistance coils, valves, etc. for operation. Thus, with the exception of wood-fired heating there is no alternative source of heat when there is an electrical power outage, unless the home has a generator.

Conclusion

Since the adoption of this measure will provide no emission reductions in Fairbanks, it is technologically infeasible and cannot be considered as BACM.

Measure 47: Inspection Warrants

Implementing Jurisdiction(s)

- Aurora, CO

Regulation Weblink(s)

- https://library.municode.com/co/aurora/codes/building_and_zoning?nodeId=BUZOCO_CH146ZO_ART12SURESPUSAC_DIV1GEUS_S146-1204BURE

Background

The City of Aurora, Colorado, authorizes the city manager, through authorized representatives, to make inspections of solid fuel heating devices that are being operated during curtailment periods. If any person refuses or restricts entry to the premises or refuses inspection of any device, the city manager is required to seek from the municipal court a warrant for inspection and an order permitting inspection at a reasonable time without interference, restriction, or obstruction (Section. 146-1204.D).

Fairbanks required installations of Borough-listed solid fuel burning appliances in new construction and replacement appliances in subsidized change-outs be performed by Borough-listed vendor/installers. Fairbanks regulations, however, did not require nor authorize Borough

[67] Appendix A of the Financing Agreement between AIDEA and IGU, December 13, 2017

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staff to perform inspections of appliance installations or operations. Fairbanks installation requirements were removed with the passage of the Home Heating Reclamation Act.

Analysis

The City of Aurora measure authorizes city staff to inspect wood heating devices in operation during curtailment periods and, if refused access by premises occupants, are required to seek inspection warrants from the municipal court. Under AS 46.03.860. Inspection Warrant, an existing statute, DEC can seek search warrants for the purpose of investigating actual or suspected sources of pollution or contamination or to ascertain compliance or noncompliance with AS 46.14 (Alaska Statue Air Quality Control) or a regulation adopted under AS 46.14.

This authority is consistent with Measure 47. Therefore implementing this measure would provide no emissions benefit if implemented in the Fairbanks nonattainment area.

Conclusion

Since the adoption of this measure will provide no emission reductions in Fairbanks, it is technologically infeasible and cannot be considered as BACM.

Measure 48: Date Certain Removal of "Coal Only Heater"

Implementing Jurisdiction(s)

- Puget Sound Clean Air Agency

Regulation Weblink(s)

- https://www.pscleanair.org/DocumentCenter/View/354

Background

Puget Sound CAA Regulation 13.07 mandates the removal of coal-only heaters located in Tacoma:

> *Any person who owns or is responsible for a coal-only heater located in the Tacoma, Washington fine particulate nonattainment area must remove and dispose of it or render it permanently inoperable by September 30, 2015.*

It also requires that owners provide documentation of the removal and disposal or rendering permanently inoperable of the coal heater to the Agency using the Agency's procedures within 30 days of the removal or rendering the heater permanently inoperable.

Fairbanks restricted the operation and installation of coal burning devices. Coal burning stoves, hydronic heaters and furnaces are defined as solid fuel burning appliances (SFBA). None of these appliances are Borough "listed appliances". All listed appliances must be EPA-certified

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and have an annual average emission rating of 2.5 grams per hour or less or 0.10 lbs/mm Btu for hydronic heaters. This effectively prohibited the installation of other types of solid fuel-fired heating devices, including coal, unless the Borough approves an independent emission test showing the device meets the emission standards. Fairbanks requirements addressing the installation and operation of coal burning devices were removed with the passage of the Home Heating Reclamation Act.

The State of Alaska adopted regulations and SIP amendments which became effective January 12, 2018 that prevented unlisted appliances (i.e., coal heaters) from being installed, sold or leased for use within the Fairbanks $PM_{2.5}$ nonattainment area. They cannot be operated during Air Quality Alerts, do not qualify for NOASH certificates, and do not qualify for the enhanced voluntary, removal, replacement and repair program.

Analysis

As discussed in the Introduction, Alaska added a new subsection to 18 AAC 50.079(f) which requires coal-fired heating devices to be removed or replaced by December 31, 2024. They must be removed or replaced prior to any conveyance of an existing building and cannot be sold, leased or distributed for sale. The removed devices must be destroyed or rendered inoperable and cannot be advertised for sale within the nonattainment area.

The removal and destruction requirements are consistent with the Measure 48 regulations mandating the date certain removal of coal only heaters. With regard to the documentation requirements, since no new coal burning units will be sold, 18 AAC 50.077 (k)(2)(A)(iii) confirmation of removal and destruction of any existing device will apply.

Conclusion

The adoption of the referenced state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 49: Prohibit Use of Coal Burning Heaters

Implementing Jurisdiction(s)

- Town of Telluride and San Miguel County, Colorado

Regulation Weblink(s)

- https://yosemite.epa.gov/R8/R8Sips.nsf/PrintSips/C5D17E5CB9461F8587257EED004BBD82?OpenDocument

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Background

The town of Telluride and San Miguel County adopted wood and coal burning emission reduction measures in the 1980's and 1990's, including provisions that:

(1) Require the installation of cleaner burning devices in existing dwellings which have pre-existing solid fuel burning devices;
(2) prohibit solid fuel burning devices in new construction;
(3) ban coal burning; and
(4) limit the total number of fireplaces and woodstoves in the nonattainment area.

These controls were approved by EPA into the Colorado PM_{10} SIP in 1994.[68]

Fairbanks air quality regulations defined coal stoves and coal burning hydronic heaters as Solid Fuel Burning Devices (SFBD). Coal burning stoves and hydronic heaters were not included as Borough-Listed Devices. Unlisted SFBDs could not be installed, did qualify for the Voluntary Replacement and Removal Program, and could not be operated during either a Stage 1 or Stage 2 Alert. Unlisted devices could receive a NOASH certification. Those regulations were Fairbanks requirements addressing the installation and operation of coal burning devices were removed with the passage of the Home Heating Reclamation Act.

Neither the Borough nor the State had regulations that banned coal burning.

EPA commented that they believed "the regulations in Telluride are more stringent than in Fairbanks. Telluride prohibits coal burning all year whereas in Fairbanks an existing coal stove can burn when there is no curtailment which could contribute additional emissions to the airshed, especially during poor conditions when a curtailment may not have been called. We do not agree with the conclusion that the PM_{10} controls are ineligible for consideration for control of $PM_{2.5}$."

Analysis

Another provision of a new subsection to 18 AAC 50.079(f) which requires coal-fired heating devices to be removed or replaced by December 31, 2024 is that a person cannot install, reinstall, sell, lease, distribute, or convey existing coal-fired heating devices. The operation restriction is not limited to curtailment Alerts and therefore directly addresses EPA's concern about contributing additional emissions to the airshed.

Conclusion

The adoption of the referenced state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

[68] https://www.gpo.gov/fdsys/pkg/FR-2001-06-15/pdf/01-15029.pdf#page=1

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Measure 50: Require Low Sulfur Content Coal

Implementing Jurisdiction(s)

- Puget Sound Clean Air Agency, State of Utah

Regulation Weblink(s)

- https://www.pscleanair.org/DocumentCenter/View/354
- https://yosemite.epa.gov/r8/r8sips.nsf/b2af5baa99cc4292872256b5f0054df73/3f2ef963733afd5a87257ef30057c077!OpenDocument

Background

Section 13.04 of the Puget Sound CAA regulations restricts the sulfur content of coal burned in a solid fuel burning device. It allows only the burning of:

> *Coal with sulfur content less than 1.0% by weight burned in a coal only heater.*

Utah regulates the sulfur and ash content of coal for residential use, with the following restrictions:

(1) After July 1, 1987, no person shall sell, distribute, use or make available for use any coal or coal containing fuel for direct space heating in residential solid fuel burning devices and fireplaces which exceeds the following limitations as measured by the American Society for Testing Materials Methods:

(a) 1.0-pound sulfur per million BTU's, and
(b) 12% volatile ash content.

(2) Any person selling coal or coal containing fuel used for direct residential space heating within the State of Utah shall provide written documentation to the coal consumer of the sulfur and volatile ash content of the coal being purchased.

Alaska DEC does not regulate the sulfur content of coal burned in solid fuel burning appliances.

Analysis

The Usibelli Coal Mine is the source of all coal marketed and burned in Fairbanks. Their factsheet[69] indicates the sulfur content of coal from the Healy mine is typically 0.2% with a range of 0.08% - 0.28%. The Healy mine supplies the coal burned in Fairbanks.

Fairbanks has no restriction on the sulfur content of coal marketed and burned within the $PM_{2.5}$ nonattainment area; therefore, the Puget Sound regulation is more restrictive. The sulfur content

[69] http://www.usibelli.com/coal/data-sheet

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of Healy coal, however, is well below the 1% threshold mandated by Puget Sound. Therefore, while the Puget Sound regulation is more restrictive, its imposition in Fairbanks will have no effect on coal burning and no emissions benefit.

The Healy fact sheet indicates that the heat content of their coal is 7,560 BTU/lb. Using this value, 132.3 lbs. of coals is needed to produce 1 million BTU. This value combined with the 0.2% content of coal produces 0.26 lbs. of sulfur, which is well below Utah sulfur threshold 1.0 lb. per million BTU. The Healy coal has a 7% average ash content ranging from 4% - 12%, which falls below the 12% volatile ash content Utah threshold.

Conclusion

The Puget Sound and Utah coal content regulations, if adopted by Alaska DEC, would not reduce $PM_{2.5}$ emissions in Fairbanks as the sole source of coal used in the Borough continuously satisfies the Puget Sound and Utah specifications; therefore, this measure is not technologically feasible and not eligible for consideration as BACM.

Measure 51: Ultra-low Sulfur Heating Oil

Implementing Jurisdiction(s)

- Northeast States and Alaska

Regulation Weblink(s)

- https://noraweb.org/wp-content/uploads/2014/11/NEMARegion_ULSDBioChart2014.pdf
- https://www.epa.gov/sites/production/files/2015-04/documents/420f06040.pdf

Background

EPA mandated the production of ultra-low sulfur (15 ppm) Diesel fuel by domestic oil refineries in 2006. Since this mandate addressed only motor vehicle fuel, no reduction in the sulfur content of home heating oil was required. Concerns about the need for reductions in ambient $PM_{2.5}$, SO_2 and regional haze, however led the Northeast states, where most heating oil consumption in the U.S. occurs, to implement laws mirroring the federal Diesel-fuel standard for motor vehicles.

In 2012, New York, which at the time had over a million households using heating oil, was the first northeastern state to set a home heating oil sulfur content standard of 15 ppm. Massachusetts, New Jersey and Vermont followed suit with a less stringent 500 ppm standard in 2014, but are all scheduled to require 15 ppm sulfur levels for heating oil by 2018. In 2016, Maine instituted a 50 ppm standard but will also require 15 ppm levels by 2018.[70] In addition many of the Mid-Atlantic States (including the District of Columbia) have also mandated the use

[70] http://blog.smarttouchenergy.com/ultra-low-sulfur-heating-oil-and-premium-fuels

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of 15 ppm heating oil by 2018. Overall, 10 states plus selected communities in other states (e.g., Philadelphia) have ultra-low sulfur heating oil requirements.[71]

During the development of the Nonroad Diesel rule, Alaska requested: 1) that June 1, 2010, be the deadline for conversion to 15 ppm sulfur highway Diesel fuel in rural Alaska; 2) that June 1, 2010, be the deadline for conversion of all nonroad, locomotive, and marine (NRLM) diesel fuel to 15 ppm sulfur content in rural Alaska; and 3) that the 15 ppm standard applicable to locomotive and marine diesel fuel produced in, imported into, and distributed or used within rural Alaska be moved up to June 1, 2010 (from the June 2012 nationwide date in the final Nonroad Diesel rule. Because the storage and distribution systems in rural Alaska are not capable of handling more than one grade of fuel, this rule effectively converted home heating fuel to a 15 ppm sulfur limit when it was implemented.

While EPA did not comment on Measure 51, it provided many comments about the state's draft report assessing the cost of producing ultra-low sulfur fuel and requested a further exploration of supply side costs and economies of scale. It also stated the "BACM analysis must start with a transparent and detailed economic analysis of exclusively supplying ultra-low sulfur heating oil to the nonattainment area."

Analysis

EPA mandated the production of ultra-low sulfur Diesel fuel in 2006; the northeast states have mandated the production and use of home heating oil with a 15 ppm sulfur limit. Storage limitations caused most communities in rural Alaska to shift all distillate fuel, including home heating oil, to a 15 ppm sulfur limit when the EPA mandate for ultra-low sulfur Diesel fuel was implemented. The use of 15 ppm home heating oil in an arctic environment has continued since 2010 without problems.

In response to the EPA comments, Alaska expanded the cost report[72] addressing the potential changes in residential home heating expenditures in the Fairbanks $PM_{2.5}$ nonattainment area given hypothetical requirements to switch to different types of heating oil. *Section I* evaluates the fuel cost difference between ultra-low sulfur (ULS) and current heating fuels – high sulfur (HS) No. 1 or No. 2 – and the cost difference between HS No. 1 and HS No. 2. *Section II* assesses how price differences found between fuels would affect household heating expenditures for the typical FNSB household. A copy of the report is included in the Appendix to Chapter 7 of the $PM_{2.5}$ Serious SIP. This information is used in the Step 4 cost effectiveness analysis and is not discussed here.

[71] https://nefi.com/news/docs/heating-oil-standards-chart.pdf

[72] Residential Fuel Expenditure Assessment of a Transition to Ultra-Low Sulfur and High Sulfur No. 1 Heating Oil for the Fairbanks PM-2.5 Serious Nonattainment Area, February 2019, Prepared by The Alaska Department of Environmental Conservation Economist in collaboration with the University of Alaska Fairbanks Master of Science Program in Resource and Applied Economics.

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Conclusion

A significant portion of the U.S., including rural Alaska, is using 15 ppm sulfur content heating oil; a significant portion of the nonattainment area is using No. 1 heating oil, therefore the two scenarios discussed above - shifts from No. 2 to No. 1 and No. 1 to ULS are eligible for consideration as BACM.

Measure 52: Operation and Sale of Small "Pot Burners" Prohibited

Implementing Jurisdiction(s)

- State of Vermont

Regulation Weblink(s)

- http://dec.vermont.gov/sites/dec/files/aqc/laws-regs/documents/AQCD_Regulations_2016_Dec.pdf

Background

Section 5-221 Prohibition of Potentially Polluting Materials in Fuel, subsection 2. Used Oil, contains the following restriction:

> *Effective July 1, 1997, the burning of used oil in small fuel burning equipment described as "pot burners" or "vaporizing" burners shall be prohibited, as shall the retail sale of these burners.*

Neither the Borough nor the State have any regulations restricting the sale of small waste or used oil burners. Borough regulations restrict the operation of waste oil appliances during Stage 1 and Stage 2 Alerts and that create a public nuisance. The State has no additional controls addressing the sale or operation of waste oil appliances.

Analysis

Vermont regulations prohibit both the operation and sale of small waste oil burning devices. Neither Alaska nor the Borough prohibit the sale of small waste oil burning devices. Both agencies have regulations that restrict the operation of waste oil devices during Air Quality Alerts and appliances that create a public nuisance.

Conclusion

Alaska has no regulations governing the sale or operation of waste oil appliances waste oil used as a heating fuel; therefore, the Vermont measures addressing waste oil are eligible for consideration as BACM.

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Measure 53: No Use Sale or Exchange of Used Oil for Fuel, unless it Meets Constituent Property Limits

Implementing Jurisdiction(s)

- State of Vermont

Regulation Weblink(s)

- http://dec.vermont.gov/sites/dec/files/aqc/laws-regs/documents/AQCD_Regulations_2016_Dec.pdf

Background

Section 5-221 Prohibition of Potentially Polluting Materials in Fuel, subsection 2. Used Oil, contains the following restriction:

> *No person shall cause or permit the use, purchase, sale or exchange in trade for use as a fuel in fuel burning equipment in Vermont of any used oil unless:*
>
> *(i) The used oil has constituents and properties within the allowable limits set forth in Table A of this section prior to blending except as provided in subsection (e) below. The Air Pollution Control Officer may prohibit the combustion of used oils containing constituents or properties not listed in Table A of this section if he/she determines that combustion of such used oil may present an unreasonable risk to public health or welfare*

Table A: Used Oil Constituents and Properties (Prior to Blending)

Constituent/Property	***Allowable[1]***
Arsenic	*5 ppm maximum*
Cadmium	*2 ppm maximum*
Chromium	*10 ppm maximum*
Lead	*100 ppm maximum*
Flash Point	*Must be 100 degrees F or more*
Total Halogens	*1000 ppm maximum*
Polychlorinated Biphenyls (PCBs)	*< 2 ppm maximum*
Net Heat of Combustion	*8000 BTU/lb minimum*
1Note: units of parts per million (ppm) are by weight on a water free basis.	

Neither the State nor the Borough have regulations addressing the purchase, sale or exchange of used oil. They also do not have regulations setting limits on waste or used oil properties.

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Analysis

Vermont regulations restrict the allowable content and transfer of waste oil used as heating fuel. There are no such restrictions governing waste or used oil as a heating fuel in Fairbanks.

Conclusion

Alaska has no regulations governing the content, use or transfer of waste oil used as a heating fuel; therefore, the Vermont measures addressing waste oil are eligible for consideration as BACM.

Measure 55: School Bus Retrofits

Implementing Jurisdiction(s)

- Oregon Department of Environmental Quality, Lane Regional Air Protection Agency

Regulation Weblink(s)

- https://www.gpo.gov/fdsys/pkg/FR-2017-11-14/html/2017-24539.htm
- http://www.lrapa.org/DocumentCenter/View/2108

Background

The RACM analysis in the Oakridge, Oregon Moderate $PM_{2.5}$ attainment plan lists Diesel retrofits of school buses as a primary control measure. No specific emissions credit, however is listed for this measure. The 2016 update to the SIP, which EPA proposed for approval, lists implementing diesel retrofits of school buses as a local transportation control measure. It also states:

> *No specific credit was taken for these mobile source programs in the 2015 attainment year emission inventory other than the normal reductions over time included in the MOVES2014a modeling.*

Neither Fairbanks nor the state has a regulation mandating the replacement of Diesel powered school buses. The Fairbanks RACM analysis evaluated *retrofit of diesel fleet (school buses, transit)* as a transportation control measure. The measure was determined to be technologically infeasible as were all measures listed in the category of transportation controls.

Analysis

EPA offers funds for the replacement of Diesel school buses through its Clean Diesel Program. The Diesel Emissions Reduction Act (DERA) provides grants for projects that reduce emissions from existing diesel engines. DERA has funded numerous diesel replacement projects in Alaska. DERA funds are currently being used to replace five diesel generators in four rural communities in Alaska. Other programs have funded diesel garbage truck, power generation and school bus

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replacement projects. The most recent diesel replacement program conducted in Fairbanks is a joint DEC/DOT&PF project[73] that replaced three heavy duty construction trucks, placed in service by the State of Alaska in 1986. That project was completed in 2010.

Oregon has funded several school bus replacement programs and included them in the Oakridge RACM analysis for the Moderate SIP, which EPA has proposed to approve. That plan, however, takes no specific emissions credit for the program and states that its benefits are included in fleet turn over benefits tracked by EPA's motor vehicle emissions simulator model (MOVES)2014b.

Conclusion

The benefits of the uncredited school bus replacement program are represented in fleet turnover calculations performed by MOVES. Since MOVES is used to represent changes in vehicle fleet emissions in Fairbanks over time, no emissions benefit is available for mandating diesel school bus replacement, therefore this measure is not technologically feasible and not eligible for consideration as BACM.

Measure 56: Road Paving

Implementing Jurisdiction(s)

- Klamath Falls, Oregon

Regulation Weblink(s)

- http://www.oregon.gov/deq/FilterDocs/KFallsAttPlan2012.pdf

Background

The 2012 $PM_{2.5}$ attainment plan for Klamath Falls includes a road paving control measure. The analysis lists road paving as an existing control measure and states:

> *PM2.5 emissions generated by motor vehicle traffic have been reduced over the years through efforts to pave roads, minimize the use of sanding material, and to control mud and dirt track out from industrial, construction and agricultural operations. Six miles of unpaved road have been paved in the nonattainment area since 2008, resulting in reductions from re-suspended road dust.*

The $PM_{2.5}$ emission reduction benefit of road paving is listed as "minimal".

Alaska does not have an emissions control measure addressing road paving in urban areas. An analysis[74] prepared in 2006 identified road paving as a fugitive dust control measure for

[73] http://dec.alaska.gov/air/anpms/projects-reports/akdot
[74] *https://dec.alaska.gov/air/anpms/Dust/Dust_docs/DustControl_Report_032006.pdf*

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implementation in rural communities in Alaska. Fairbanks has no control measures addressing road paving. Unlike many communities in the lower-48, roads in the Fairbanks nonattainment area remain frozen during winter months. The emissions inventory discussion in Step 1 noted that fugitive dust sources of $PM_{2.5}$ are estimated to be negligible under the snow/ice bound conditions reflected in the winter seasonal inventory.

Analysis

The Klamath Falls SIP claims "minimal" $PM_{2.5}$ emission benefit for a fugitive dust control measure. Since fugitive dust emissions in Fairbanks are negligible during the winter, the application of fugitive dust controls with "minimal" benefits in a more moderate climate will produce no benefits.

Conclusion

Fugitive dust control measures will provide no wintertime $PM_{2.5}$ benefit in Fairbanks, therefore it is technologically infeasible and not eligible for consideration as BACM.

Measure 58: Controls on Road Sanding and Salting

Implementing Jurisdiction(s)

- Utah Department of Environmental Quality

Regulation Weblink(s)

- https://documents.deq.utah.gov/air-quality/pm25-serious-sip/DAQ-2017-011685.pdf
- https://documents.deq.utah.gov/air-quality/pm25-serious-sip/DAQ-2017-011686.pdf
- https://documents.deq.utah.gov/air-quality/pm25-serious-sip/DAQ-2017-011687.pdf

Background

Draft BACM analyses for the Logan, Provo, and Salt Lake Areas in Utah's Serious $PM_{2.5}$ SIP has identified Road Salting & Sanding as a control measure. The analysis prepared for each community included the following finding:

> *R307-307 Road Salting & Sanding: The purpose of this rule is to establish emission control for winter time road salting. This is an existing rule that was part of the PM10 SIP (Section IX, Part A, Page 57) that was approved by EPA on December 6, 1999 (64 FR 68031). A RACT analysis was conducted as part of that SIP. The rule was amended by expanding the applicability to include PM2.5 nonattainment areas as part of the moderate PM2.5 SIP. The actual PM emission reduction is unknown however, past UDAQ studies have indicated that road salt plays a minimal role related to this SIP. Consequently, no further analysis is warranted.*

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Fairbanks and Alaska do not have an emissions control measure addressing either road sanding or road salting. Unlike many communities in the lower-48, roads in the Fairbanks nonattainment area remain frozen during winter months. The emissions inventory discussion in Step 1 noted that fugitive dust sources of $PM_{2.5}$ are estimated to be negligible under the snow/ice bound conditions reflected in the winter seasonal inventory.

Analysis

Utah is planning to expand the applicability of the Road Sanding & Salting control measure, a PM_{10} fugitive dust control measure, to the Logan, Provo and Salt Lake $PM_{2.5}$ nonattainment areas. The analysis states that the $PM_{2.5}$ benefit of the measure is "unknown" and no credit is taken for the measure.

Since fugitive dust emissions in Fairbanks are negligible during the winter, the application of fugitive dust controls with "unknown" benefits in Utah's more moderate climate will produce no benefits in Fairbanks.

Conclusion

Fugitive dust control measures will provide no wintertime $PM_{2.5}$ benefit in Fairbanks, therefore this measure is technologically infeasible and not eligible for consideration as BACM.

Measure 60: Vehicle Idling Restrictions

Implementing Jurisdiction(s)

- Many – EPA published a report summarizing state and local idle control programs in 2008.[75]

Regulation Weblink(s)

- None

Background

EPA received "multiple inquiries regarding community interest in controlling emissions from idling" and commented that "these types of controls should be further evaluated in BACM and MSM analyses."

Analysis

The EPA compilation of idle programs listed regulations from 31 different states. A review of the regulations listed in the report found the programs were focused on controlling heavy-duty

[75] EPA420-B-06-004 "Compilation of State, County and Local Anti-Idling Regulations", April 2008

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vehicle activity for a variety of reasons, including: noise, fuel consumption and emissions. Controls addressing light-duty vehicle activity were conspicuously absent. A literature review and related searches could find no SIPs taking particulate emissions credit for anti-idling programs. Texas for example has an extensive anti-idling program focused on reducing NOx emissions. Another consideration is that a survey of heavy-duty truck operators in Fairbanks conducted by DEC staff found that none kept their vehicles idling for extended periods (e.g., overnight) as it was cheaper from both a fuel consumption and a maintenance perspective to keep their vehicles stored indoors when not in use.

A complicating factor when considering the benefits of anti-idling programs in Alaska is that emission control system performance deteriorates at cold temperatures when engines are turned off and catalysts cool down. A study conducted by Sierra Research[76] found there was little or no air quality benefit from turning off a warmed-up vehicle if it was going to be started soon thereafter. For example, they found that turning-off a warmed vehicle during a short (60 minute or less) shopping errand provides no CO air quality benefit. The emissions from a vehicle left running were roughly comparable to a vehicle that was turned off and re-started at the end of the errand. While that study did not address tradeoffs in particulate emission reductions it demonstrated that lower-48 control program benefits do not necessarily apply in Alaska and that careful consideration of cold temperatures on emission control system performance needs to be considered in the evaluation of anti-idling programs. Sierra conducted a test program[77] for DEC that measured light-duty vehicle $PM_{2.5}$ emissions under alternative temperatures and modes of operation. The data and analysis conducted in that study, however, have not been used to assess the potential benefits of an anti-idling program on $PM_{2.5}$ emissions during winter operating conditions in Fairbanks.

Given the challenges of assessing the benefits of an anti-idling control program in Alaska, the finding that it produced no CO emission benefit for light-duty gasoline powered vehicles and the finding that no SIPs have taken credit for particulate emission reductions leads to the conclusion that there is no evidence this measure produces a particulate emissions benefit.

Conclusion

There no evidence this program provides a particulate emissions reduction under cold temperature conditions in Fairbanks, therefore it is not technologically feasible and not eligible for consideration as BACM.

[76]Di Genova, F., et al, "Fairbanks Cold Temperature Vehicle Testing: Warmup Idle, Between-trip Idle, and Plug-in," prepared for Alaska Department of Environmental Conservation by Sierra Research, January 2002.

[77] DiGenova, F. et al, "Characterizing Vehicular Contributions to PM2.5 in Fairbanks, Alaska, Volume 1: Dynamometer-Based Emissions Measurements, Vehicle Keep-warm Activities and MOVES Analysis, December 2012 (Volumes 1 – 4)

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Measure 61: Fuel Oil Boiler Upgrade – Burner Replacement/Repair

Implementing Jurisdiction(s)

- None

Regulation Weblink(s)

- None

Background

EPA commented that the benefits fuel oil boiler maintenance should be investigated as a control measure.

Analysis

Despite the finding that no benefits for this type of control program have been found in SIPs, information collected for the emissions inventory found that over 60% of the homes in the nonattainment area are heated with fuel oil and most are equipped with fuel oil boilers. Discussions with local vendors and repair technicians were conducted to determine the magnitude of potential fuel consumption benefits from cleaning and replacing burners. It was found that the benefits depend on the age of the boiler and level of regular maintenance.

Brookhaven National Laboratory conducted an extensive evaluation of [78] the effects of maintenance on fuel consumption and emissions of fuel oil boilers and found significant benefits; little information however was found about the benefits of burner replacement. Despite this limitation and the lack of detailed information about the age of fuel oil boilers and related maintenance intervals, it is clear that a program mandating regular maintenance has the potential reduce fuel use and emissions from fuel oil boilers.

Conclusion

Test measurements have demonstrated that improved fuel oil boiler maintenance reduces fuel consumption and emissions, therefore this measure is technologically feasible. This finding addresses EPA's comments.

Measure 62: Fuel Oil Boiler Upgrade – Replacement

Implementing Jurisdiction(s)

- None

[78] Roger J. McDonald, Brookhaven National Laboratory, "Evaluation of Gas, Oil and Wood Pellet Fueled Residential Heating System Emissions Characteristics" Energy Sciences and Technology Department, December 2009

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Regulation Weblink(s)

- None

Background

EPA commented that the benefits fuel oil boiler upgrades should be investigated as a control measure.

Analysis

Despite the finding that no benefits for this type of control program have been found in SIPs, information collected for the emissions inventory found that over 60% of the homes in the nonattainment area are heated with fuel oil and most are equipped with fuel oil boilers. Discussions with local vendors and repair technicians were conducted to determine the magnitude of potential fuel consumption benefits from upgrading/replacing fuel oil boilers. It was found that the benefits depend on the age of the boiler and level of regular maintenance.

Brookhaven National Laboratory conducted an extensive evaluation[79] of emissions from a variety of fuel oil boilers and furnaces (e.g., conventional, condensing, etc.) using fuels of varying sulfur levels and found that technology has a significant benefit. Detailed information about the age and maintenance intervals of the existing stock of fuel oil boilers, however is required to assess the benefits of a program mandating upgrades/replacement. While this information is not available for homes located in the nonattainment area, the Brookhaven report indicates that newer technologies reduce emissions.

Conclusion

Test measurements have demonstrated that more efficient fuel oil boilers reduce emissions, therefore this measure is technologically feasible. This finding addresses EPA's comments.

Measure 63: Require Electrostatic Precipitators

Implementing Jurisdiction(s)

- None

Regulation Weblink(s)

- None

[79] Roger J. McDonald, Brookhaven National Laboratory, "Evaluation of Gas, Oil and Wood Pellet Fueled Residential Heating System Emissions Characteristics" Energy Sciences and Technology Department, December 2009

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Background

ESPs are pollution control devices that use electrical forces to remove fine particulate matter (PM) from exhaust streams. PM collection in an ESP occurs in three steps: suspended particles are given an electrical charge; the charged particles migrate to a collecting electrode; and the collected PM is dislodged or cleaned from the collecting electrode. ESP technology has been available for over a century and successfully employed on numerous industrial applications in the U.S., and throughout the world, with typical PM control efficiencies of 90% – 99%. Central to achieving the aforementioned performance is site specific design, continuous monitoring, and periodic maintenance; i.e. ESPs are not one size fits all, and are not plug and play.

Other countries, most notably European countries, have implemented ESPs on residential wood stoves. The technology transfer from the industrial sector to the residential sector required each country to address key issues not inherent in the technology itself; e.g. site specific design, continuous monitoring, and periodic maintenance. A review of regulations from Zurich, Switzerland, where ESPs may be retrofitted on handcrafted wood stoves to meet standards in cases where laboratory certification is not practical. Zurich also encourages the use of ESPs in general to reduce emissions, but does not provide any additional regulatory incentive to use an ESP. Notable regulations that address monitoring and maintenance requirements include:

- Annual inspections to verify proper device operation and use of clean dry fuel;
- Annual chimney sweep by certified professional;
- All hydronic heating systems subject to emission measurements every 2 years;
- Only dry and untreated wood may be burned. In case of doubt, an ash sample is collected, analyzed by a laboratory, and judged by the authorities; and,
- Minimum of 60% control efficiency for retrofit control devices, such as ESPs.

No SIPs or EPA guidance documents were identified requiring the installation of an ESP or any retrofit control device on

Analysis

A review of applicable SIPs and EPA guidance documents could find no requirements for retrofitting wood stoves with ESPs. While ESPs appear to offer a potential emission reductions, there are several obstacles to successful implementation. The lack of regulatory framework and regulatory authority to certify and guarantee long term performance is one obstacle, specifically:

- The EPA does not have any certification process for retrofit control devices on wood stoves; and,
- The regulatory framework at the local, state, and federal level lack the necessary language to exclude devices with unproven performance (e.g. homemade devices).

No other jurisdiction in the United States has implemented a monitoring and maintenance plan at a residential level that guarantees operation of a retrofit emission control device which create the following obstacles:

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- ESPs require professional installation, there are a lack of trained professionals and currently no way to verify installation;
- ESPs require periodic chimney cleanings, currently there is no way to verify cleaning; and,
- ESPs require periodic maintenance, there are a lack of trained professionals and currently no way to verify maintenance.

The implementation strategy, i.e. incentive for residents to purchase and install ESPs, is not clearly identified which is another obstacle. Community members view ESP installation in lieu of burn bans as the incentive to install; however that strategy could lead to worse air quality conditions if ESP performance deteriorates over time, and there are legal issues regarding backsliding with the Fairbanks Moderate State Implementation Plan (SIP). Another implementation strategy would be a requirement to install ESPs on certain devices (e.g. devices that are exempt from burn bans), which would achieve the highest air quality benefit but would be viewed as regulatory overreach by the community.

Conclusion

No SIPs or EPA guidance were identified with requirements for retrofitting wood stoves with ESPs; therefore, this measure is classified as a MSM to be addressed in a subsequent SIP.

Measure 64: Weatherization and Energy Efficiency

Implementing Jurisdiction(s)

- None

Regulation Weblink(s)

- None

Background

EPA commented that weatherization and heat retention programs should be evaluated as a control measure. They suggested evaluating the benefits of energy audits and increased insulation. The survey of SIPs did not identify any control measures mandating weatherization and claiming related emission reduction benefits.

Analysis

Given the high cost of home heating, Alaska has many programs for improving home heating efficiency. The Alaska Housing Finance Corporation offers a variety of programs that offer information (e.g., air sealing, appliance efficiency, insulation, home maintenance, ventilation, etc.) and financial incentives (home energy loans, rebates and low income weatherization, etc.) to improve home heating efficiency. The Alaska Energy Authority provides a wide range of programs to improve heating efficiency. Another source of information for constructing new

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homes is the IECC Compliance Guide for Homes in Alaska, which provide guidance on air sealing, fenestration, insulation and ducts.

All of these programs and codes lead to home heating efficiency improvements, which reduce emissions.

Conclusion

Programs which stimulate home heating system replacement produce heating efficiency improvements and credit for both the efficiency improvement and emissions reductions are accounted for in the control measure analysis for the SIP. Energy audits, increased insulation and related weatherization measures are also being implemented on a voluntary basis, so they are clearly technologically feasible and available for consideration as BACM. However, since these measures were not mandated in other SIPs, they have been classified as MSM and will be addressed in a subsequent SIP. This finding addresses EPA's comments.

Measure 65: Emissions Crossing Property Lines

Implementing Jurisdiction(s)

- None

Regulation Weblink(s)

- None

Background

Prior to the Proposition 4 vote on the Home Heating Reclamation Act, Fairbanks Code included a restriction on visible emissions crossing property lines. That requirement, however, was removed from Borough Code.

Analysis

The fact that this requirement was previously in place, clearly demonstrates that it is technologically feasible. As noted in the introduction, a new regulation 18 AAC 50.075(f)(2) requires that solid fuel fired heating devices shall be operated so that visible emissions do not cross property lines.

Conclusion

The adoption of the referenced state regulation is sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 66: Curtailment Threshold

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Implementing Jurisdiction(s)

- San Joaquin Valley APCD
- Sacramento APCD

Regulation Weblink(s)

- http://www.valleyair.org/pmplans/documents/2018/pm-plan-adopted/2018-Plan-for-the-1997-2006-and-2012-PM2.5-Standards.pdf
- http://www.airquality.org/ProgramCoordination/Documents/Rule421%20Presentation%20092409%20Item5.pdf

Background

In a March 22, 2019 Federal Register Notice[80], EPA proposed to "approve revisions to the Alaska State Implementation Plan (SIP) that were submitted by the Alaska Department of Environmental Conservation (ADEC). These proposed revisions update and strengthen ADEC's regulation of residential wood smoke emissions, especially the curtailment program applying to the Fairbanks fine particulate matter nonattainment area."

Analysis

The thresholds proposed for adoption are 25 and 35 µg/m^3 for Stage 1 and Stage 2 curtailment respectively. As noted in Measure 40, more stringent curtailment thresholds are in place in San Joaquin Valley and Sacramento. Recognizing the need for additional emission reductions and the lower thresholds found in other control programs, Alaska has modified it Emergency Episode Plan and lowered the Stage 1 and Stage 2 curtailment thresholds to 20 and 30 µg/m^3 respectively.

Conclusion

The adoption of Emergency Episode Plan requirements are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 67: Coffee Roasters

Implementing Jurisdiction(s)

- Colorado

Regulation Weblink(s)

- https://www.colorado.gov/pacific/sites/default/files/AP_Coffee-Roasting.pdf

[80] Federal Register / Vol. 84, No. 56 / Friday, March 22, 2019

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Background

Alaska Department of Environmental Conservation (ADEC) regulation 18 AAC 50.055 imposes emission limits on industrial processes and fuel-burning equipment that are applicable to coffee roasting operations in the Fairbanks North Star Borough. This regulation limits the opacity of visible emissions from fuel-burning equipment to no more 20 percent averaged over any six consecutive minutes.[81] Neither ADEC nor the Borough have adopted regulations specific to emissions from coffee roasting operations.

Though not having regulations specific to the reduction of emissions from coffee roasters, a number of jurisdictions outside of Alaska do have permit requirements for facilities from which emissions exceed a specific threshold, and coffee roasting facilities are not exempted from these requirements.

A summary of the State Implementation Plans for Colorado,[82] as developed by the Regional Air Quality Management Council[83] – which was established in 1989 to serve as the lead air quality planning agency for the Denver metropolitan area – indicates that in 1987, Denver was designated as a "Group I" nonattainment area for PM_{10} and then designated as a moderate attainment area in 1990 with regard to the 24-hour PM_{10} standards. Among the control measures contained within the 1993 PM_{10} Attainment SIP was one that stated that:

All existing permits and applicable provisions of AQRs[84] No. 1 and 3 enforced for both minor and major industrial sources of PM_{10}, NO_x and SO_2.
The Colorado Department of Public Health and Environment (CDPHE) currently enforces Regulation Number 3: Stationary Source Permitting and Air Pollutant Emission Notice Requirements,[85] which requires that:

For criteria pollutants, Air Pollutant Emission Notices are required for: each individual emission point in a nonattainment area with uncontrolled actual emissions of one ton per year or more of any individual criteria pollutant (pollutants are not summed) for which the area is nonattainment; each individual emission point in an attainment or attainment/maintenance area with uncontrolled actual emissions of two tons per year or more of any individual criteria pollutant (pollutants are not summed)

[81] http://dec.alaska.gov/media/1038/18-aac-50.pdf, accessed June 20, 2018.
[82] https://raqc.egnyte.com/dl/SMXBbYwYdO/StateImplementationPlanSummaries2018.pdf_; updated January 2018, accessed April 11. 2018.
[83] http://raqc.org/
[84] Air Quality Regulation
[85] Colorado Department of Public Health and Environment, Air Quality Control Commission, Regulation Number 3: Stationary Source Permitting and Air Pollutant Emission Notice Requirements, available at https://www.colorado.gov/pacific/sites/default/files/5-CCR-1001-5.pdf, accessed April 11, 2018.

Also listed within Regulation Number 3 is a list of facilities for which exemption from Regulation Number 3 could be granted, but coffee roasting facilities are not included within that list. In fact, in 2014 the CDPHE's Air Pollution Control Division released a memo entitled "An Overview of Colorado Air Regulations for Coffee Roasting",[86] which lists these same limits for exemptions, implying that the requirement has been maintained despite Colorado having achieved attainment status for PM_{10}. Lastly, direct communication with the Air Pollution Control Division of the Colorado Department of Public Health confirmed that no regulation has ever been developed specifically for coffee roasting facilities within Colorado and that any permitting requirements for coffee roasting facilities within Colorado has just been part of the overall permitting or New Source Review requirements.[87]

The requirements for coffee roasting operations exceeding either of the emission thresholds are the maintenance of visible emissions at opacity levels of 20% of less, and the use of a cyclone capable of reducing uncontrolled particulate matter emissions by at least 70%.[88]
In addition to Colorado, other jurisdictions have indicated a requirement for coffee roasters to apply for permits related to their operations:

- Oregon requires permits for facilities that process thirty or more tons of roasted coffee per year.[89]
- The San Diego County Air Pollution Control District Rules require a permit for "any coffee roaster with a maximum capacity above 11 pounds"[90] and guidance specific to coffee roasting operations states that emissions from coffee roasting "are typically controlled using a combination of a cyclone and either an afterburner or wet-scrubber."[91]
- Washington Administrative Code 173-401-530 defines the threshold for insignificant emissions, and thus permitting requirements, as 0.75 tons per year of PM_{10}[92] and does not exempt coffee roasters.
- The Rules of the South Coast Air Quality Management District (SCAQMD) mention coffee roasting facilities only as facilities for which no permits are required unless a facility is subject to Regulation IX (Standards for Performance of New Stationary Sources), or Regulation X (National Emissions Standards for Hazardous Air Pollutants),

[86] https://www.colorado.gov/pacific/sites/default/files/AP_Coffee-Roasting.pdf
[87] Communication with Casey Houlden, Air Pollution Control Division, Colorado Department of Public Health, April 16, 2018; Communication with Leah Martland, Air Pollution Control Division, Colorado Department of Public Health, April 16, 2018
[88] An Overview of Colorado Air Regulations for: Coffee Roasting, Colorado DPHE Air Pollution Control Division, Small Business Assistance Program, 8/2014, p. 7, https://www.colorado.gov/pacific/sites/default/files/AP_Coffee-Roasting.pdf (accessed on June 14, 2018)
[89] http://www.oregon.gov/deq/FilterPermitsDocs/aqgp116.pdf
[90] https://www.arb.ca.gov/drdb/sd/curhtml/R11.pdf
[91] https://www.sandiegocounty.gov/content/sdc/apcd/en/engineering/Permits/Engineering_Phase_2/Coffee_Roasters.html
[92] http://apps.leg.wa.gov/wac/default.aspx?cite=173-401-530

both of which are general in nature and not related specifically to coffee roasting facilities.[93,94]

- The Sacramento Metropolitan Air Quality Management District has also not adopted any regulations specific to coffee roasting facilities,[95] but does maintain a specific webpage to assist coffee roasting facilities with the acquisition of a permit for new installations or modifications of facilities.[96]
- The Puget Sound Clean Air Agency does not have any regulations specific to coffee roasting facilities,[97] and coffee roasting facilities are not listed in Regulation 1-9,[98] which sets requirements for specific sources.[99]
- The New York State Department of Environmental Conservation does not have any apparent regulations specific to coffee roasters,[100] and the list of SIP-approved measures applicable in New York does not include any specific to coffee roasting operations,[101] implying that such operations in New York State are subject only to permit requirements.
- The Idaho Department of Environmental Quality, in rule 58.01.01, Rules for Control of Air Pollution in Idaho, makes no specific mention of coffee roasting facilities.[102]
- The Bay Area Air Quality Management District, in a manner similar to the SCAQMD, states that coffee roasting facilities "with a roasting capacity of less than 15 pounds of beans or nuts per hour" are "exempt from the requirements of Sections 2-1-301 and 302," which are the permitting standards for construction and operation of facilities.[103]

To ensure that coffee roasters are properly represented in the emissions inventory, ADEC staff identified batch roasting facilities located within the nonattainment area and conducted a telephone survey to collect information on capacity (lbs/year), utilization, existing controls, etc. Due to concerns about regulation and competition the responses were limited and provided no insight into their operations. One respondent, however noted their facility employed a thermal oxidizer to control emissions.

[93] SCAQMD, 2017, Rules. Available at https://www.epa.gov/sites/production/files/2018-01/documents/south_coast_district_rules_compilation_dec_2017.pdf, accessed May 2, 2018.
[94] http://www.aqmd.gov/home/rules-compliance/rules/scaqmd-rule-book/regulations-ix-and-x
[95] https://www.epa.gov/sites/production/files/2018-01/documents/sacramento_metropolitan_air_quality_management_district_aqmd_rules_compilation_dec_2017.pdf
[96] http://www.airquality.org/businesses/permits-registration-programs/permit-applications-recordkeeping-advisories/coffee-bean-roasting-operations
[97] http://www.pscleanair.org/219/PSCAA-Regulations
[98] http://www.pscleanair.org/DocumentCenter/View/342/1-9-PDF
[99] http://www.pscleanair.org/101/Permits-Registration; http://www.pscleanair.org/181/Title-V-Operating-Permits
[100] http://www.dec.ny.gov/regulations/regulations.html
[101] https://www.epa.gov/sips-ny/epa-approved-statutes-and-regulations-new-york-sip
[102] https://adminrules.idaho.gov/rules/current/58/580101.pdf
[103] https://www.epa.gov/sites/production/files/2018-01/documents/san_francisco_bay_area_air_quality_management_district_baaqmd_rules_compilation.pdf

Analysis

The permit requirement of the San Diego County Air Pollution Control District for use of a cyclone in combination with an afterburner or wet scrubber appears to constitute the most stringent emission control requirement on emissions from coffee roasting operations. The use of a cyclone with an afterburner or wet scrubber will typically result in visible emissions from coffee roasting operations that are substantially less than 20 percent opacity. Although this permit requirement is not contained in an approved $PM_{2.5}$ SIP, the inclusion of this control technology as the standard for control expected in a permit application makes this technology eligible for consideration as BACM.

The finding that a thermal oxidizer is currently used to control emissions from a facility located within the nonattainment area demonstrates that this measure is technologically feasible.
As noted in the introduction, a new regulation 18 AAC 50.078(d) requires coffee roasters within an area identified in 18 AAC 50.015(b)(3) to install a pollution control device appropriate to the unit, approved by the department, such as a catalytic oxidizer or thermal oxidizer unless the facility provides information to the department demonstrating the control technology is technically or economically infeasible. The requirement for installation of control equipment on coffee roasters will be 1 year from the effective date of regulation

Conclusion

The adoption of the referenced state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure 68: Charbroilers

Implementing Jurisdiction(s)

- Bay Area Air Quality Management District (California)
- South Coast Air Quality Management District (California)
- San Joaquin Valley Unified Air Pollution Control District (California)

Regulation Weblink(s)

- http://www.baaqmd.gov/~/media/dotgov/files/rules/reg-6-rule-2-commercial-cooking-equipment/documents/rg0602.pdf?la=en;
- http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1138.pdf?sfvrsn=4,
- http://www.valleyair.org/rules/currntrules/r4692.pdf

Background

Alaska Department of Environmental Conservation (ADEC) regulation 18 AAC 50.055 imposes emission limits on industrial processes and fuel-burning equipment that are applicable to charbroiling operations in the Fairbanks North Star Borough. This regulation limits the opacity

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of visible emissions from fuel-burning equipment to no more 20 percent averaged over any six consecutive minutes. Neither ADEC nor the Borough have adopted regulations specific to emissions from charbroiling operations.

Charbroiling – either chain-driven or under-fire - is a method of flame-cooking meat that is popular in restaurants or other commercial cooking operation where speed and production volume in the preparation of cooked meats are priorities. In chain-driven charbroiling, meat is carried on a slotted, conveyorized grill between two sets of gaseous fuel burners, one above the grill and one below.[104] In under-fire charbroiling, a stationary slotted grill holds the meat while it is exposed to radiant heating from gaseous fuel burners located below the grill. A few air quality regulatory agencies have adopted emission control requirements to reduce $PM_{2.5}$ emissions from charbroiler operations.

The Bay Area Air Quality Management District (California) adopted Regulation 6, Rule 2 (Commercial Cooking Equipment) in 2007 to reduce PM emissions from both chain-driven and under-fire charbroiling sources.[105] The rule requires:

- for chain-driven charbroilers with a throughput of at least 400 pounds of beef per week, the use of a catalytic oxidizer that reduced PM_{10} emissions to no more than 1.3 pounds per 1000 pounds of beef cooked per manufacturer's certification, or any other control device that limits the PM_{10} emissions to 0.74 pounds per 1000 pounds of beef cooked as determined by onsite source testing; and
- for under-fire charbroilers processing more than 800 pounds per week on more than 10 square feet of cooking area, the use of a control device certified to limit PM_{10} emissions to no more than 1 pound of PM_{10} per 1,000 pounds of cooked beef.

The South Coast Air Quality Management District adopted Rule 1138 (Control of Emissions from Restaurant Operations) in 1997 to control emissions from chain-driven charbroilers only.[106] The Rule requires the use of catalytic oxidizers to control PM_{10} emissions from chain-driven charbroilers, but does not set a specific emission limit. Charbroilers in operation as of November 14, 1997 are allowed a ten year delay in compliance. All new or retrofitted charbroiler systems must submit source test data to the AQMD upon initial startup with catalytic oxidizers installed. Chain-driven charbroilers permitted with a meat processing limit of less than 875 pounds of meat per week, as documented by weekly records maintained for five years of meat purchased and

[104] South Coast Air Quality Management District, Preliminary Draft Staff Report: Proposed Amended Rule 1138 – Control of Emissions from Restaurant Operations, 2009, available at http://www.aqmd.gov/docs/default-source/rule-book/support-documents/rule-1138/par1138pdsr.pdf, accessed on April 12, 2018.
[105] Bay Area Air Quality Management District, Regulation 6 – Particulate Matter Rule 2 Commercial Cooking Equipment, http://www.baaqmd.gov/~/media/dotgov/files/rules/reg-6-rule-2-commercial-cooking-equipment/documents/rg0602.pdf?la=en, accessed on June 21, 2018.
[106] http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1138.pdf?sfvrsn=4, accessed on June 21, 2018.

cooked, and demonstrating through source testing that PM_{10} emissions are less than one pound per day, are exempt from the requirement to use a catalytic oxidizer.

The San Joaquin Valley Unified Air Pollution Control District last amended Rule 4692 (Commercial Charbroiling) in 2009 to control emissions from chain-driven charbroilers only.[107] The Rule requires charbroilers processing more than 875 pounds of meat per week to be equipped and operated with a catalytic oxidizer certified by South Coast AQMD to have a control efficiency of at least 83% for PM_{10} emissions. Charbroilers processing less than 875 pounds of meat per week are exempt from the requirement to install catalytic oxidizers if weekly records of meat purchased and cooked are maintained for five years and source testing demonstrates the maximum meat processing rates at which PM_{10} emissions are maintained at less than one pound per day. Charbroilers processing less than 400 pounds of meat per week, or less than 10,800 pounds in the most recent 12 month period and less than 875 pounds in any single week, are exempt from the requirements to install catalytic converters and from the requirements for source testing.

The Utah Department of Environmental Quality last amended R307-303 (Commercial Cooking) in 2018 to control $PM_{2.5}$ emissions from chain-driven charbroilers in $PM_{2.5}$ nonattainment counties.[108] This regulation requires the use of catalytic oxidizers on all chain-driven charbroilers in these jurisdictions, regardless of meat processing capacity. The regulation also requires that the opacity of exhaust from catalytic oxidizers serving chain-driven charbroilers not exceed 20% using U.S. EPA Method 9.

Analysis

The Utah DEQ regulation requires catalytic oxidizers on all chain-driven charbroilers in specified counties, but does not require the catalytic oxidizers to be certified to a specific emission limit as required by the Bay Area AQMD or the San Joaquin Valley UAPCD. Catalytic oxidizers satisfying the Bay Area AQMD mass emission rate or the San Joaquin Valley UAPCD control efficiency should operate at visible emission opacities considerably below the Utah DEC 20% limit. These controls are technologically feasible.

As noted in the introduction, a new regulation 18 AAC 50.078(c) requires charbroilers to submit information on their location, operation type (chain driven versus underfire), number of operations, fuel used, # of lbs of meat cooked/week, etc. This information is required to develop charbroiler regulations.

Conclusion

The adoption of the referenced state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required. Once responses are received, DEC will review and analyze the results and will determine in future SIP updates whether they need to be addressed.

[107] http://www.valleyair.org/rules/currntrules/r4692.pdf, accessed on June 21, 2018.
[108] https://rules.utah.gov/publicat/code/r307/r307-303.htm, accessed on June 21, 2018.

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Measure 69: Incinerators

Implementing Jurisdiction(s)

- South Coast AQMD
- Washington State
- Colorado
- South Coast AQMD
- New York State

Regulation Weblink(s)

- See footnotes

Background

The Alaska Department of Environmental Conservation, under the Alaska Administrative Code 18.AAC.50.050 – Incinerator Emission Standards, PM emissions are restricted to the levels, which vary with the size of the facility, that are shown in the following table:[109]

Incinerator	Particulate Matter Standard
Rated capacity less than 1,000 pounds per hour	No limit
Rated capacity greater than or equal to 1,000 but less than 2,000 pounds per hour	0.18 grams per cubic foot of exhaust gas corrected to 12 percent carbon dioxide and standard conditions, averaged over three hours
Rated capacity greater than or equal to 2,000 pounds per hour	0.08 grams per cubic foot of exhaust gas corrected to 12 percent carbon dioxide and standard conditions, averaged over three hours
An incinerator that burns waste containing more than 10 percent wastewater treatment plant sludge by dry weight from a municipal wastewater treatment plant that serves 10,000 or more persons	0.93 grams per kilogram of dry sludge input

These restrictions were most recently amended in 2008.

[109] Alaska Administrative Code Title 18, Environmental Conservation, Chapter 50 Air Quality Control, available at https://www.epa.gov/sites/production/files/2017-10/documents/sip-ak-approved-regulations-18-aac-50.pdf, accessed April 16, 2018

Under a regulation last amended in 1992, San Joaquin Valley APCD Rule 4203 (Particulate Matter Emissions From Incineration of Combustible Refuse) restricts particulate matter emissions from refuse incinerators to less than 0.10 pounds per 100 pounds of refuse burned. [110] The rule also limits particulate emissions to 0.10 grains per dry standard cubic foot (gr/dscf) of exhaust gas corrected to 12% CO_2 for incinerators having burn rates in excess of 100 pounds per hour, and to 0.30 gr/dscf corrected to 12% CO_2 for incinerators having burn rates less than or equal to 100 pounds per hour.

South Coast AQMD Rule 473 (Disposal of Solid and Liquid Wastes) imposes similar particulate matter emission limits on incinerators.[111] For incinerators with design combustion rates greater than 110 pounds per hour, the emission limit is 0.1 gr/dscf corrected to 12% CO_2. For incinerators with design combustion rates less than or equal to 110 pounds per hour, the emission limit is 0.3 gr/dscf corrected to 12% CO_2.

The Washington Department of Ecology Rule 173-434-130 (Solid Waste Incinerator Facilities) requires that incinerators capable of burning 250 or more tons of solid waste per day emit no more than 0.020 gr/dscf corrected to 7% O_2, and that incinerators capable of burning more than 12 tons but less than 250 tons of solid waste per day emit no more than 0.030 gr/dscf corrected to 7% O_2. In addition, Rule 173-434-160 requires the combustion zone temperature not fall below 1600 degrees F, or not average less than 1800 degrees F over any fifteen-minute period, or that the combustion air leaving the chamber must maintain an oxygen concentration of at least 3% on a wet basis.[112]

Restrictions similar to those in Alaska have been adopted by the Colorado Department of Public Health & Environment, where - in areas designated as non-attainment or attainment/maintenance for particulate matter - no owner or operator of an incinerator is allowed to cause or permit particulate matter emissions of more than 0.10 gr/dscf corrected to 12 % CO_2. In areas designated as attainment for particulate matter, the emission limit if 0.15 gr/dscf corrected to 12 % CO_2.[113]

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[110] San Joaquin Valley Unified Air Pollution Control District, Rule 4203 Particulate Matter Emissions from Incineration of Combustible Refuse (Adopted May 21, 1992, Amended December 17, 1992), available at http://www.valleyair.org/rules/currntrules/r4203.pdf, accessed April 12, 2018

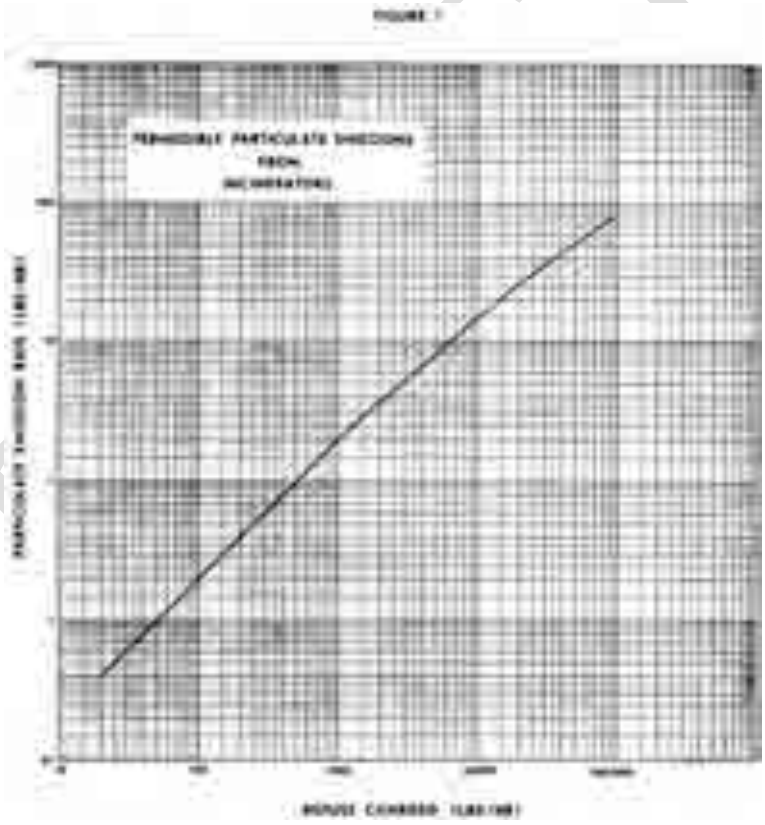
[111] http://www.aqmd.gov/docs/default-source/rule-book/rule-iv/rule-473.pdf?sfvrsn=4, accessed on June 25, 2018.

[112] Washington State Legislature, Chapter 173-434, Solid Waste Incinerator Facilities, available at http://apps.leg.wa.gov/wac/default.aspx?cite=173-434&full=true, accessed April 12, 2018

[113] Colorado Department of Public Health and Environment, Air Quality Control Commission, Regulation No. 1 Emission Control for Particulate Matter, Smoke, Carbon Monoxide, and Sulfur Oxides 5 CCR1001-3, 2007, available at https://www.colorado.gov/pacific/sites/default/files/5-CCR-1001-3.pdf, accessed April 12, 2018

San Diego County Air Pollution Control District Rule 53 limits combustion particulate emissions from incinerators to 0.10 gr/dscf corrected to 12% CO_2, except for those with a rated capacity of 100 pounds per hour or less, which are limited to 0.30 gr/dscf corrected to 12% CO_2.[114]

New York State Department of Environmental Conservation Codes, Rules and Regulations Chapter III, Part 219 (Incinerators), Subpart 2.2 (Emission Limitations) limits particulate matter emissions from incinerators statewide to 0.010 gr/dscf corrected to 7% O_2. Subpart 6.2 (Existing Incinerators – New York City, Nassau and Westchester Counties; Particulate Emissions) limits particulate emissions from existing incinerators to values displayed in the following figure:



[114] San Diego County Air Pollution Control District, Rule 1. Title, available at https://www.epa.gov/sites/production/files/2018-01/documents/san_diego_county_air_pollution_control_district_apcd_rules_compilation_dec_2017.pdf, accessed April 16, 2018

New York State DEC regulations also limit particulate emissions for existing incinerators in other portions of the state to values displayed in a different, less restrictive figure. Other sections of Part 219 place restrictions on the O_2 and CO_2 exhaust content and minimum combustion temperatures, among other requirements.[115]

Analysis

The regulatory emission limitations of particulate matter from incinerators enforced by San Joaquin Valley APCD, South Coast AQMD, San Diego County APCD, Washington State DEQ, Colorado DPHE, and New York State DEC are all more restrictive than those applicable to incinerators in Fairbanks, and are therefore technologically feasible.

As noted in the introduction, a new regulation 18 AAC 50.078(c) requires incinerators to submit information on location, type (medical, liquid, solid, etc.), process, fuel, throughput, hours of operation, etc. This information is required to develop more stringent incinerator regulations.

Conclusion

The adoption of the referenced state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required. Once responses are received, DEC will review and analyze the results and will determine in future SIP updates whether they need to be addressed.

Measure 70: Used Oil Burners

Implementing Jurisdiction(s)

- State of Vermont

Regulation Weblink(s)

- https://dec.vermont.gov/sites/dec/files/aqc/laws-regs/documents/AQCD%20Regulations%20ADOPTED_Dec132018.pdf

Background

Measures 52 and 53 addressed controls mandated by the State of Vermont prohibiting the burning of used fuel oil in small "pot burners" or vaporizing burners. Both measures were

[115] Westlaw Compilation of New York Codes, Rules, and Regulations, Subpart 219-2 Municipal and Private Solid Waste Incineration Facilities, available at https://govt.westlaw.com/nycrr/Browse/Home/NewYork/NewYorkCodesRulesandRegulations?guid=Ib66e7530b5a011dda0a4e17826ebc834&originationContext=documenttoc&transitionType=Default&contextData=(sc.Default)&bhcp=1, accessed April 12, 2018.

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determined to be technologically feasible. In the process of considering a set of regulations governing the accumulation, distribution and burning of used oil, it was determined that little information is available about the extent of used oil burning in Fairbanks. Calls to local vendors confirmed that used oil is burned, however, no detailed information about the number of facilities and homes burning waste oil or the volumes used has been collected. This measure is designed to collect the information required to formulate a used oil burning program

Analysis

As noted in the introduction, a new regulation 18 AAC 50.078(c) requires used oil burners to submit information on the location, # of burners, rating, operating hours, fuel use/hour, etc.

Conclusion

The adoption of the referenced state regulation is sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required. Once responses are received, DEC will review and analyze the results and will determine in future SIP updates whether they need to be addressed.

Measure R1: Regional Kilns

Implementing Jurisdiction(s)

- None

Regulation Weblink(s)

- http://dec.alaska.gov/air/anpms/comm/docs/fbxSIPpm2-5/Appendix_III.D.5.07_Adopted_12.24.14.pdf

Background

BACM analysis requirements specified in the final $PM_{2.5}$ rule mandate the consideration of "options not previously considered as RACM/RACT for the area". The moderate SIP considered funding the construction of a Regional Kiln to provide a source of dry wood. The RACM analysis determined the measure to be technologically infeasible because of concerns about the demand for dry wood and emissions from fuels used to dry the wood.

EPA commented that this measure should be further evaluated for BACM and MSM.

Analysis

The review of SIP commitments did not identify a single program which mandates the construction of Regional Kilns to provide a source of dry wood. Instead, several programs implemented measures that require the use of dry wood in solid fuel burning devices. Fairbanks

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implemented a requirement that prohibits burning wood that "has more than 20 percent moisture content" in a solid fuel burning appliance.[116]

Conclusion

No SIPs or EPA guidance was identified requiring regional; therefore, this measure is not eligible for consideration as BACM, but is eligible for consideration as MSM in a subsequent SIP.

Measure R4: All Wood Stoves Must be Certified

Implementing Jurisdiction(s)

- None

Regulation Weblink(s)

- http://dec.alaska.gov/air/anpms/comm/docs/fbxSIPpm2-5/Appendix_III.D.5.07_Adopted_12.24.14.pdf

Background

BACM analysis requirements specified in the final $PM_{2.5}$ rule mandate the consideration of "options not previously considered as RACM/RACT for the area". The RACM analysis listed a wood stove measure entitled "All Units Must be Certified". While no analysis of the measure was presented, it was determined to be technologically infeasible. Klamath County was the reference for the measure. The Klamath County Clean Air Ordinance[117] requires:

> *Non-certified wood stoves and fireplace inserts must be removed from building upon sale any building containing them (Section 406.100(3)(c)).*

The Klamath County ordinance also addresses non-certified wood stoves by requiring:

> *The resale or installation of a non-certified solid fuel-fired appliance or any appliance not meeting the requirements of Section 406.005(31) is prohibited[118] (Section 406.100(3)(a)(i)).*

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116 http://www.codepublishing.com/AK/FairbanksNorthStarBorough/#!/FNSBC21/FNSBC2128.html#21.28.030

117 https://www.klamathcounty.org/DocumentCenter/Home/View/1020

118 Section 406.005(31) provides a definition of "Urban Growth Boundary" and appears to be an obsolete reference. Most probably, the reference should be to 406.005(10), which is a definition of "Certified Woodstove or Fireplace Insert".

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The resale, or installation of an exempt solid fuel-fired appliance, is allowed in accordance with state and local requirements (Section 406.100(3)(a)(ii)).

EPA commented "These measures do not reference the Puget Sound Clean Air Agency (Section 13.07) requirement for removal of all uncertified stoves by September 30, 2015. This is equivalent to having all solid fuel burning appliances be certified and would be more stringent than the current SIP approved rules in Fairbanks. We believe that these measures need to be evaluated in the BACM and MSM analyses." EPA also commented that "All Wood Stoves Must be Certified."

Analysis

As discussed in the analysis of Measures 15 and 17, Alaska's new regulations 18 AAC 50.077(b) specify that a person may not operate, install, reinstall, sell, lease, distribute, or convey wood-fired heating devices that lack a valid EPA certification under 40 C.F.R. 60.533 or any wood-fired outdoor hydronic heaters, except pellet fueled devices, including those that have a qualifying "white tag" under EPA's Phase 2 voluntary partnership program. All noncompliant devices must be removed or replaced by December 31, 2024, removed or replaced prior to property conveyance and destroyed or rendered inoperable. The new state regulation 18 AAC 50.077(k)(2) also requires confirmation of removal and destruction of any existing device shall be provided to the department. Alaska's new removal requirements are significantly more stringent than Klamath County's ordinance removal requirements, which only address uncertified wood stoves; they also address EPA's comments about removal concerns. The confirmation, removal, destruction and notification requirements are more stringent than those specified in Measure R4 (and Puget Sound Clean Air Agency's Section 13.07) and will provide no emission benefits if implemented in the Fairbanks nonattainment area.

Conclusion

The adoption of the referenced state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure R5: Ban New Installations – Hydronic Heaters

Implementing Jurisdiction(s)

- Utah

Regulation Weblink(s)

- https://rules.utah.gov/publicat/code/r307/r307-208.htm
- http://dec.alaska.gov/air/anpms/comm/docs/fbxSIPpm2-5/Appendix_III.D.5.07_Adopted_12.24.14.pdf

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Background

BACM analysis requirements specified in the final $PM_{2.5}$ rule mandate the consideration of "options not previously considered as RACM/RACT for the area". The moderate SIP considered a measure requiring a ban on new installations of hydronic heaters. Analysis of the measure was limited:

> *A ban on new installations would not reduce emissions from hydronic heaters in the near term, but would ultimately reduce emissions as hydronic heaters were retired. However, this approach could have the negative effect of prolonging the use of existing, dirty units because replacing them with newer, much cleaner units would not be allowed. As a result, this measure would not result in quantifiable reductions in the four years after designation.*

The RACM analysis determined the measure to be technologically infeasible because it lacked the authority to implement it. That finding lapsed, but again became effective with voter approval of the Home Heating Reclamation Act in the fall of the 2018.

EPA commented that "Measure R5 describes a similar rule in Utah but lists "none" under implementing jurisdictions. Please make consistent." The reference to Utah was added above under the title of implementing jurisdiction.

Analysis

The review of SIP commitments determined that Utah Rule R-307-208-5 bans the installation of new OWBs; it allows the replacement of existing OWBs with an EPA Phase 2 qualified wood pellet outdoor wood boiler.

Alaska has repealed and replaced 18 AAC 50.077. Several subsections address hydronic heaters, including:

> *(b) a person may not operate, install, reinstall, sell, lease, distribute, or convey wood-fired heating devices that lack a valid EPA certification under 40 C.F.R. 60.533 or any wood-fired outdoor hydronic heaters, except pellet fueled devices, including those that have a qualifying "white tag" under EPA's Phase 2 voluntary partnership program.*
> *(c) a person may not supply, sell, lease, distribute, or convey a non-pellet fueled wood-fired hydronic heater for operation or installation in the nonattainment area;*
> *(d) a person may not operate, install, or reinstall a pellet fueled wood-fired hydronic heater in the nonattainment area; and may not supply, sell, lease, distribute, or convey a pellet fueled wood-fired hydronic heater for operation or installation in the nonattainment area.*

An additional 18 AAC 50.077 (b) requirement states that all noncompliant devices must be removed or replaced by December 31, 2024, removed or replaced prior to property conveyance and destroyed or rendered inoperable. 18 AAC 50.077(k)(2) requires confirmation of removal

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and destruction of any existing device shall be provided to the department. Collectively, the new regulations are more stringent than the Utah requirements.

Conclusion

The adoption of the referenced state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure R6: Remove Hydronic Heaters at Time of Home Sale

Implementing Jurisdiction(s)

- None

Regulation Weblink(s)

- http://dec.alaska.gov/air/anpms/comm/docs/fbxSIPpm2-5/Appendix_III.D.5.07_Adopted_12.24.14.pdf

Background

BACM analysis requirements specified in the final $PM_{2.5}$ rule mandate the consideration of "options not previously considered as RACM/RACT for the area". The moderate SIP considered a measure requiring the removal of hydronic heaters at the time of home sale. Analysis of the measure was limited:

> *A requirement to replace hydronic heaters at the time of home sale would not reduce emissions from hydronic heaters in the near term, but would ultimately reduce emissions as hydronic heaters were retired when residential property changed hands. As a result, this measure would not result in quantifiable reductions in the four years after designation. The cost of the measure would be borne by the seller, because the home's sale price would be diminished by the value of the heater that must be removed.*

The analysis did not define or examine what the removed hydronic heaters should be replaced with. Klamath Falls was the reference for the measure. A review of the Klamath County Clean Air Ordinance[119] found a requirement to disclose the presence of all solid fuel-fired appliances upon sale of real property, including wood stoves, fireplace inserts, fireplaces and pellet stoves. The only removal requirement contained in the Ordinance states:

> *Removal of Non-Certified Woodstoves and Fireplace Inserts upon Sale of Real-Property – Non-certified wood stoves and fireplace inserts must be removed from building upon sale of any building containing them. The removal shall be accomplished prior to the*

[119] https://www.klamathcounty.org/DocumentCenter/Home/View/1020

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closing of any real estate transaction involving the building containing the non-certified wood stove(s) or fireplace insert(s).

The RACM analysis determined the measure to be technologically infeasible because it lacked the authority to implement it. That finding lapsed, but again became effective with voter approval of the Home Heating Reclamation Act in the fall of the 2018.

While the Borough has no Ordinance addressing the removal of uncertified heating devices from homes being sold, the state of Alaska has mandated a program to remove uncertified wood burning devices during property transactions in the Fairbanks Nonattainment Area; this program became effective June 9, 2017.[120] The regulations require removal or replacement of non-compliant wood-fired heating devices before the sale, lease, or conveyance of property within the Nonattainment Area.

EPA commented that these measures should be evaluated at the state and local level.

Analysis

As noted in the analysis of Measure R5, Alaska has repealed and replaced 18 AAC 50.077. Several subsections address hydronic heaters, subsection (b) states a person may not install, reinstall, sell, lease, distribute, or convey wood-fired heating devices that lack a valid EPA certification under 40 C.F.R. 60.533 or any wood-fired outdoor hydronic heaters, except pellet fueled devices, including those that have a qualifying "white tag" under EPA's Phase 2 voluntary partnership program. Additional requirements include:

(1) shall remove or replace an existing device identified in this subsection by December 31, 2024, or
(2) shall remove or replace an existing device before it is sold, leased or conveyed as part of an existing building; and
(3) shall destroy or render inoperable the removed device.

Collectively, the new regulations are more stringent than the Measure R4 requirements and they address EPA comments about the need to evaluate the measure at a state level. Local implementation of any rules for the next 2 years is not possible because of the passage of the Fairbanks Home Heating Reclamation Act, therefore EPA's comment about evaluation at a local level cannot be addressed at this time.

Conclusion

The adoption of the referenced state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

[120] http://dec.alaska.gov/air/anpms/comm/docs/18AAC50.077.pdf

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Measure R7: Ban Use of Hydronic Heaters

Implementing Jurisdiction(s)

- None

Regulation Weblink(s)

- http://dec.alaska.gov/air/anpms/comm/docs/fbxSIPpm2-5/Appendix_III.D.5.07_Adopted_12.24.14.pdf

Background

BACM analysis requirements specified in the final $PM_{2.5}$ rule mandate the consideration of "options not previously considered as RACM/RACT for the area". The moderate SIP considered banning the use of hydronic heaters. The RACM analysis determined the measure to be technologically infeasible because it did include a provision for homes with no other adequate source of heat. Another consideration was that on very cold days some residences with alternate heat sources find them to be inadequate and need to supplement with heat from wood combustion.

EPA commented that "Measure R7, Ban Use of Hydronic Heaters, incorrectly identifies that no other SIPs implemented the measure as rationale for not evaluating."

Analysis

The review of SIP commitments did not identify a single program with unrestricted bans on using hydronic heaters. Instead, those programs with curtailments specify the conditions under which curtailments/Air Quality Alerts are called and those programs include a variety of exemptions for homes with NOASH certifications, economic hardship, etc. Fairbanks has implemented a measure mandating stage 1 and stage 2 alerts which restrict wood burning when concentrations are forecast to exceed established concentration thresholds (i.e., 25 and 35 $\mu g/m^3$ respectively). Under these conditions use of hydronic heaters are prohibited except under the exemptions specified in the rule.[121]

While a SIP commitment banning outdoor wood boilers (furnaces, etc.) was not identified, several communities in Connecticut (e.g. West Hartford, Hamden, Avon, etc.) were found to have ordinances banning outdoor wood boilers because of nuisance complaints. Commitments to implementing those ordinances, however are not contained in Connecticut's $PM_{2.5}$ SIP.[122] The SIP references a state statute (Section 22a-174k),[123] which restricted the installation of new

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[121] http://www.codepublishing.com/AK/FairbanksNorthStarBorough/#!/FNSBC21/FNSBC2128.html#21.28.030

[122] http://www.ct.gov/deep/cwp/view.asp?A=2684&Q=419074&depnav_GID=1619

[123] https://law.justia.com/codes/connecticut/2012/title-22a/chapter-446c/section-22a-174k/

outdoor wood burning furnaces until EPA issued regulations for hydronic heaters; it also specified setback requirements for new installations. The recent passage of the Fairbanks Home Heating Reclamation Act, required the removal of any solid fuel burning regulations, so again the Borough lacks the authority to curtail wood stove use. The new state regulations implemented in 18 AAC 50.077 and the Episode Chapter of the $PM_{2.5}$ Serious SIP restrict wood-fired heating device operation, but do not ban all operation.

Conclusion

No SIPs or EPA guidance was identified banning the use of hydronic heaters; therefore, this measure is not eligible for consideration as BACM, but is eligible for consideration as MSM in a subsequent SIP, which addresses EPA's comments.

Measure R9: All Wood Stoves Must be Certified

Implementing Jurisdiction(s)

- None

Regulation Weblink(s)

- http://dec.alaska.gov/air/anpms/comm/docs/fbxSIPpm2-5/Appendix_III.D.5.07_Adopted_12.24.14.pdf

Background

This measure is the same as Measure R4. To preserve the numbering sequence, the text from Measure R4 is repeated here.

BACM analysis requirements specified in the final $PM_{2.5}$ rule mandate the consideration of "options not previously considered as RACM/RACT for the area". The RACM analysis listed a wood stove measure entitled "All Units Must be Certified". While no analysis of the measure was presented, it was determined to be technologically infeasible. Klamath County was the reference for the measure. The Klamath County Clean Air Ordinance[124] requires:

> *Non-certified wood stoves and fireplace inserts must be removed from building upon sale any building containing them (Section 406.100(3)(c)).*

The Klamath County ordinance also addresses non-certified wood stoves by requiring:

[124] https://www.klamathcounty.org/DocumentCenter/Home/View/1020

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The resale or installation of a non-certified solid fuel-fired appliance or any appliance not meeting the requirements of Section 406.005(31) is prohibited[125] *(Section 406.100(3)(a)(i)).*

The resale, or installation of an exempt solid fuel-fired appliance, is allowed in accordance with state and local requirements (Section 406.100(3)(a)(ii)).

EPA commented "These measures do not reference the Puget Sound Clean Air Agency (Section 13.07) requirement for removal of all uncertified stoves by September 30, 2015. This is equivalent to having all solid fuel burning appliances be certified and would be more stringent than the current SIP approved rules in Fairbanks. We believe that these measures need to be evaluated in the BACM and MSM analyses". EPA also commented that "All Wood Stoves Must be Certified."

Analysis

As discussed in the analysis of Measures 15 and 17, Alaska's new regulation 18 AAC 50.077(b) specifies that a person may not install, reinstall, sell, lease, distribute, or convey wood-fired heating devices that lack a valid EPA certification under 40 C.F.R. 60.533 or any wood-fired outdoor hydronic heaters, except pellet fueled devices, including those that have a qualifying "white tag" under EPA's Phase 2 voluntary partnership program. All noncompliant devices must be removed or replaced by December 31, 2024, removed or replaced prior to property conveyance and destroyed or rendered inoperable. The new state regulations 18 AAC 50.077(k)(2) also requires confirmation of removal and destruction of any existing device shall be provided to the department. Alaska's new removal requirements are significantly more stringent than Klamath County's ordinance removal requirements, which only address uncertified wood stoves; they also address EPA's comments about removal concerns. The confirmation, removal, destruction and notification requirements are more stringent than those specified in Measure R4 (and Puget Sound Clean Air Agency's Section 13.07) and will provide no emission benefits if implemented in the Fairbanks nonattainment area.

Conclusion

The adoption of the referenced state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure R10: Replace Uncertified Units at the Time of Sale

Implementing Jurisdiction(s)

- None

[125] Section 406.005(31) provides a definition of "Urban Growth Boundary" and appears to be an obsolete reference. Most probably, the reference should be to 406.005(10), which is a definition of "Certified Woodstove or Fireplace Insert".

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Regulation Weblink(s)

- http://dec.alaska.gov/air/anpms/comm/docs/fbxSIPpm2-5/Appendix_III.D.5.07_Adopted_12.24.14.pdf

Background

BACM analysis requirements specified in the final $PM_{2.5}$ rule mandate the consideration of "options not previously considered as RACM/RACT for the area". The moderate SIP considered a measure requiring *replacement of a stove at the time of sale*. Analysis of this measure was limited:

> *A requirement to replace uncertified stoves at the time of home sale would not reduce emissions from wood stoves in the near term, but would ultimately reduce emissions as wood stoves were retired when residential property changed hands. As a result, this measure would not result in quantifiable reductions in the four years after designation. The cost of the measure would be borne by the seller, because the home's sale price would be diminished by the value of the stove that must be removed.*

The analysis did not define or examine what the removed uncertified wood stoves should be replaced with. Klamath Falls was the reference for the measure. A review of the Klamath County Clean Air Ordinance[126] found a requirement to disclose the presence of all solid fuel-fired appliances upon sale of real property, including wood stoves, fireplace inserts, fireplaces and pellet stoves. The only removal requirement contained in the Ordinance states:

> *Removal of Non-Certified Woodstoves and Fireplace Inserts upon Sale of Real-Property – Non-certified wood stoves and fireplace inserts must be removed from building upon sale of any building containing them. The removal shall be accomplished prior to the closing of any real estate transaction involving the building containing the non-certified wood stove(s) or fireplace insert(s).*

The RACM analysis determined the measure to be technologically infeasible because it lacked the authority to implement it. That finding was based on a local voter referendum prohibiting the Borough's regulation of home heating which lapsed. The recent passage of the Fairbanks Home Heating Reclamation Act, required the removal of any solid fuel burning regulations, so again the Borough lacks the authority to remove uncertified wood-fired heaters.

While the Borough has no Ordinance addressing the removal of uncertified heating devices from homes being sold, the state of Alaska has mandated a program to remove uncertified wood burning devices during property transactions in Fairbanks; this program became effective June 9, 2017.[127] The regulations require removal or replacement of non-compliant wood-fired heating devices before the sale, lease, or conveyance of property within the Nonattainment Area.

[126] https://www.klamathcounty.org/DocumentCenter/Home/View/1020
[127] http://dec.alaska.gov/air/anpms/comm/docs/18AAC50.077.pdf

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Analysis

As noted in the analysis of Measures 15, 17, R4/R9 and particularly R6 which addressed the removal of hydronic heaters at the time of home sale, Alaska has repealed and replaced 18 AAC 50.077. Subsection (b) states a person may not operate, install, reinstall, sell, lease, distribute, or convey wood-fired heating devices that lack a valid EPA certification under 40 C.F.R. 60.533 or any wood-fired outdoor hydronic heaters, except pellet fueled devices, including those that have a qualifying "white tag" under EPA's Phase 2 voluntary partnership program. Additional requirements include:

(1) shall remove or replace an existing device identified in this subsection by December 31, 2024, or
(2) shall remove or replace an existing device before it is sold, leased or conveyed as part of an existing building; and
(3) shall destroy or render inoperable the removed device.

This regulation directly addresses the replacement of uncertified units at the time of sale as Measure R10 requires.

Conclusion

The adoption of the referenced state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure R11: Replace Uncertified Stoves at the Time of Significant Remodeling

Implementing Jurisdiction(s)

- None

Regulation Weblink(s)

- http://dec.alaska.gov/air/anpms/comm/docs/fbxSIPpm2-5/Appendix_III.D.5.07_Adopted_12.24.14.pdf

Background

BACM analysis requirements specified in the final $PM_{2.5}$ rule mandate the consideration of "options not previously considered as RACM/RACT for the area". The moderate SIP considered a measure requiring replacement of a stove when significant remodeling occurred. Analysis of the measure discussed:

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It would probably be enforced during the building permit review and issuance process. The scope and impact of this measure could be controlled by definition of "significant;" it could also be limited to situations where the remodeled room contains a stove. A requirement to replace uncertified stoves at the time of significant remodeling would not reduce emissions from wood stoves in the near term, but would ultimately reduce emissions as wood stoves were retired when residential property was remodeled. As a result, this measure would not result in quantifiable reductions in the four years after designation. The cost of the measure would be borne by the homeowner.

The RACM analysis determined the measure to be technologically infeasible because it lacked the authority to implement it. That finding was based on a Borough the referendum prohibiting the Borough's regulation of home heating which lapsed. The recent passage of the Fairbanks Home Heating Reclamation Act, required the removal of any solid fuel burning regulations, so again the Borough lacks the authority to remove or replace uncertified wood-fired heaters.

Analysis

As noted in the analysis of Measures 15, 17, R4/R9 and particularly R6 and R10 which addressed the removal of hydronic heaters and uncertified stoves at the time of home sale, Alaska has repealed and replaced 18 AAC 50.077. Subsection (b) states a person may not operate, install, reinstall, sell, lease, distribute, or convey wood-fired heating devices that lack a valid EPA certification under 40 C.F.R. 60.533 or any wood-fired outdoor hydronic heaters, except pellet fueled devices, including those that have a qualifying "white tag" under EPA's Phase 2 voluntary partnership program. Additional requirements include:

(1) shall remove or replace an existing device identified in this subsection by December 31, 2024, or
(2) shall remove or replace an existing device before it is sold, leased or conveyed as part of an existing building; and
(3) shall destroy or render inoperable the removed device.

This regulation directly addresses the replacement of uncertified units at the time of remodeling that Measure R10 requires.

Conclusion

The adoption of the referenced state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure R12: Replace Uncertified Stoves in Rental Units

Implementing Jurisdiction(s)

- None

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Regulation Weblink(s)

- http://dec.alaska.gov/air/anpms/comm/docs/fbxSIPpm2-5/Appendix_III.D.5.07_Adopted_12.24.14.pdf

Background

BACM analysis requirements specified in the final $PM_{2.5}$ rule mandate the consideration of "options not previously considered as RACM/RACT for the area". The moderate SIP considered a measure requiring the replacement of uncertified units in rental units. Analysis of the measure was limited:

> *A requirement to replace uncertified stoves in rental units would result in emission reductions upon replacement. The cost of the measure would be borne by the landlords, and presumably passed on to the renter.*

The RACM analysis determined the measure to be technologically infeasible because it lacked the authority to implement it. That finding was based on a Borough the referendum prohibiting the Borough's regulation of home heating which lapsed. The recent passage of the Fairbanks Home Heating Reclamation Act, required the removal of any solid fuel burning regulations, so again the Borough lacks the authority to remove or replace uncertified wood-fired heaters.

EPA commented that this measure should be further evaluated for BACM and MSM.

Analysis

As noted in the analysis of Measures 15, 17, R4/R9, R6, R10 and R11, Alaska has repealed and replaced 18 AAC 50.077. Subsection (b) states a person may not operate, install, reinstall, sell, lease, distribute, or convey wood-fired heating devices that lack a valid EPA certification under 40 C.F.R. 60.533 or any wood-fired outdoor hydronic heaters, except pellet fueled devices, including those that have a qualifying "white tag" under EPA's Phase 2 voluntary partnership program. Additional requirements include:

> *(1) shall remove or replace an existing device identified in this subsection by December 31, 2024, or*
> *(2) shall remove or replace an existing device before it is sold, leased or conveyed as part of an existing building; and*
> *(3) shall destroy or render inoperable the removed device.*

This regulation directly addresses the replacement of uncertified units in all buildings, including rental units that Measure R10 requires and addresses EPA's comments.

Conclusion

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The adoption of the referenced state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure R15: Ban New Installations – Wood Stoves

Implementing Jurisdiction(s)

- None

Regulation Weblink(s)

- http://dec.alaska.gov/air/anpms/comm/docs/fbxSIPpm2-5/Appendix_III.D.5.07_Adopted_12.24.14.pdf

Background

BACM analysis requirements specified in the final $PM_{2.5}$ rule mandate the consideration of "options not previously considered as RACM/RACT for the area". The moderate SIP considered a measure requiring a ban on new installations of wood stoves. Analysis of the measure was limited:

> *A ban on new installations would not reduce emissions from wood stoves in the near term, but would ultimately reduce emissions as wood stoves were retired; however, this approach could have the negative effect of prolonging the use of existing, dirty units because replacing them with newer, much cleaner units would not be allowed. This measure would not result in quantifiable reductions in the four years after designation.*

Discussion of other wood stove restrictions (e.g., limit the number of new installations allowed in new construction, allow new installations but only if one or more existing stoves were retired first, etc.) was also presented. Ultimately, the RACM analysis determined the measure to be technologically infeasible because it lacked the authority to implement it. That finding was based on a Borough the referendum prohibiting the Borough's regulation of home heating which lapsed. The recent passage of the Fairbanks Home Heating Reclamation Act, required the removal of any solid fuel burning regulations, so again the Borough lacks the authority to remove or replace uncertified wood-fired heaters.

EPA commented that "Measure R15 is technologically feasible."

Analysis

The review of SIP commitments did not identify a single program which bans new installations of wood stoves.

This measure parallels Measure R5, which bans the installation of hydronic heaters. The findings for Measure R5 also apply for Measure R15 and are presented below with edits

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addressing wood stoves instead of hydronic heaters. Note, the new Alaska rules apply to hydronic heaters and to wood stoves.

Alaska has repealed and replaced 18 AAC 50.077. Several subsections address wood-fired heating devices, including:

> *(b) a person may not operate, install, reinstall, sell, lease, distribute, or convey wood-fired heating devices that lack a valid EPA certification under 40 C.F.R. 60.533 or any wood-fired outdoor hydronic heaters, except pellet fueled devices, including those that have a qualifying "white tag" under EPA's Phase 2 voluntary partnership program.*
> *(e) a person may not supply, sell, lease, distribute, or convey a catalyst equipped woodstove or pellet fueled woodstove for operation or installation in the nonattainment area unless it meets the certification criteria noted in (b).*
> *(f) a person may not supply, sell, lease, distribute, or convey a non-catalyst equipped woodstove or pellet fueled woodstove for operation or installation in the nonattainment area unless it meets the certification criteria noted in (b).*

An additional 18 AAC 50.077 (b) requirement states that all noncompliant devices must be removed or replaced by December 31, 2024, removed or replaced prior to property conveyance and destroyed or rendered inoperable. 18 AAC 50.077(k)(2) requires confirmation of removal and destruction of any existing device shall be provided to the department. Collectively, the new regulations are more stringent than the R15 requirements and address EPA's comments.

Conclusion

No SIPs or EPA guidance were identified banning the use of wood stoves; therefore, this measure is not eligible for consideration as BACM, but is eligible for consideration as MSM in a subsequent SIP.

Measure R16: Disincentives to Sell Used Stoves

Implementing Jurisdiction(s)

- None

Regulation Weblink(s)

- http://dec.alaska.gov/air/anpms/comm/docs/fbxSIPpm2-5/Appendix_III.D.5.07_Adopted_12.24.14.pdf

Background

BACM analysis requirements specified in the final $PM_{2.5}$ rule mandate the consideration of "options not previously considered as RACM/RACT for the area". The moderate SIP considered a measure imposing a financial penalty on the sale of a used stove to another user. Analysis of the measure was limited:

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This measure could apply to all sales of used stoves, or limited to uncertified stoves. There is little environmental benefit to discouraging the sale of a used certified stove; most of the incremental benefit of stove changeout is the difference between uncertified and certified stove emissions.

Enforcement of this measure would be much more difficult than enforcement of the requirement that all new stoves be certified. Enforcement of the latter measure requires that vendors be monitored. Enforcement of a penalty on resale would require that transactions involving individual sellers be monitored. This, in turn, might be addressed using a permit or registration system for stove owners.

The short-term effectiveness of this measure is low, as the turnover of wood stoves built before 1992 is very slow.

The RACM analysis determined the measure to be technologically infeasible because it lacked the authority to implement it. That finding was based on a Borough the referendum prohibiting the Borough's regulation of home heating which lapsed.

Borough Code[128] has been updated since the RACM analysis was prepared and Section 21.28.030 (Prohibited acts) mandates:

No person shall sell or lease an unlisted solid fuel burning appliance or barrel stove kit in the borough unless the buyer signs an affidavit, on a form prescribed by the borough, attesting that the appliance will not be installed or used in the air quality control zone (Section 21.28.030(H)(1))

Uncertified wood stoves are not included as a Borough listed solid fuel burning appliance.

The recent passage of the Fairbanks Home Heating Reclamation Act, required the removal of any solid fuel burning regulations, so again the Borough lacks the authority to influence the sale of used stoves

While this requirement does not apply to the transfer of property, the state of Alaska has mandated a program to remove uncertified wood burning devices during property transactions in Fairbanks; this program became effective June 9, 2017.[129] The regulations require removal or replacement of non-compliant wood-fired heating devices before the sale, lease, or conveyance of property within the Nonattainment Area.

Analysis

128 http://www.codepublishing.com/AK/FairbanksNorthStarBorough/#!/FNSBC21/FNSBC2128.html#21.28

129 http://dec.alaska.gov/air/anpms/comm/docs/18AAC50.077.pdf

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Measures adopted by the state require the removal of uncertified wood stoves from homes being sold. As discussed above Alaska has repealed and replaced 18 AAC 50.077. Several subsections address wood-fired heating devices, including:

> *(b) a person may not operate, install, reinstall, sell, lease, distribute, or convey wood-fired heating devices that lack a valid EPA certification under 40 C.F.R. 60.533 or any wood-fired outdoor hydronic heaters, except pellet fueled devices, including those that have a qualifying "white tag" under EPA's Phase 2 voluntary partnership program.*
> *(e) a person may not supply, sell, lease, distribute, or convey a catalyst equipped woodstove or pellet fueled woodstove for operation or installation in the nonattainment area unless it meets the certification criteria noted in (b).*
> *(f) a person may not supply, sell, lease, distribute, or convey a non-catalyst equipped woodstove or pellet fueled woodstove for operation or installation in the nonattainment area unless it meets the certification criteria noted in (b).*

An additional 18 AAC 50.077 (b) requirement states that all noncompliant devices must be removed or replaced by December 31, 2024, removed or replaced prior to property conveyance and destroyed or rendered inoperable. 18 AAC 50.077(k)(2) requires confirmation of removal and destruction of any existing device shall be provided to the department. While these regulations do not address the financial disincentives considered in this measure, they go one step further by banning the sale or conveyance of uncertified wood-fired heating device.

Collectively the new regulations are more stringent than the R16 requirements.

Conclusion

The adoption of the referenced state regulations are sufficient to meet the BACM requirements of this measure, therefore the measure is technologically feasible and no additional analysis is required.

Measure R17: Ban Use of Wood Stoves

Implementing Jurisdiction(s)

- None

Regulation Weblink(s)

- http://dec.alaska.gov/air/anpms/comm/docs/fbxSIPpm2-5/Appendix_III.D.5.07_Adopted_12.24.14.pdf

Background

BACM analysis requirements specified in the final $PM_{2.5}$ rule mandate the consideration of "options not previously considered as RACM/RACT for the area". The moderate SIP considered banning the use of wood stoves. The RACM analysis determined the measure to be

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technologically infeasible because it did not include an exemption for homes with no other adequate source of heat. Another consideration was that on very cold days some residences with alternate heat sources find those sources to be inadequate, and need to supplement with heat from wood combustion.

EPA commented that this measure should be further evaluated for BACM and MSM.

Analysis

The review of SIP commitments did not identify a single program with unrestricted bans on using wood stoves. Instead, those programs with curtailments specify the conditions under which curtailments/Air Quality Alerts are called and those programs include a variety of exemptions for homes with NOASH certifications, economic hardship, etc. Fairbanks has implemented a measure mandating stage 1 and stage 2 alerts which restrict wood burning when concentrations are forecast to exceed established concentration thresholds (i.e., 25 and 35 $\mu g/m^3$ respectively). Under these conditions use of wood stoves are prohibited except under the exemptions specified in the rule.[130] The recent passage of the Fairbanks Home Heating Reclamation Act, required the removal of any solid fuel burning regulations, so again the Borough lacks the authority to curtail wood stove use. The new state regulations implemented in 18 AAC 50.077 and the Episode Chapter of the $PM_{2.5}$ Serious SIP restrict wood-fired heating device operation, but do not ban all operation.

Conclusion

No SIPs or EPA guidance was identified banning the use of wood stoves; therefore, this measure is not eligible for consideration as BACM, but is eligible for consideration as MSM in a subsequent SIP. This finding addresses EPA's comments.

Measure R20: Transportation Control Measures

Implementing Jurisdiction(s)

- None

Regulation Weblink(s)

- http://dec.alaska.gov/air/anpms/comm/docs/fbxSIPpm2-5/Appendix_III.D.5.07_Adopted_12.24.14.pdf

Background

130 http://www.codepublishing.com/AK/FairbanksNorthStarBorough/#!/FNSBC21/FNSBC2128.html#21.28.030

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BACM analysis requirements specified in the final $PM_{2.5}$ rule mandate the consideration of "options not previously considered as RACM/RACT for the area". The moderate SIP considered several transportation control measures, including:

- HOV lanes
- Traffic flow improvement program
- Create non-motorized traffic zones
- Employer-sponsored flexible work schedules
- Retrofit diesel fleet (school buses, transit fleets)
- On-road vehicle I/M program
- Heavy-duty vehicle I/M program
- State LEV program

Transportation control programs in place at the time included:

- Expanded availability of plug-ins; electrical outlets were installed on 1,500+ parking spaces between 2008 & 2015
- Ordinance mandating—for employers with 275+ parking spaces—electrification of outlets at temps < 21° F between November 1 and March 31
- Public education focused on the benefits of plugging-in and using the transit program called Metropolitan Area Commuter System (MACS)
- Expanded transit service includes improved service frequency on high ridership routes, new routes and better bus stop facilities; ridership increased 61% between 2008 & 2013
- Commuter Van Pool program, includes Van Tran program for elderly and disabled
- Anti-idling program for heavy-duty diesel vehicles started as a ADOT&PF program focused on dump trucks and tractors and has been expanded to a CMAQ-funded pilot program focused on the purchase and installation of auxiliary heaters to reduce idle time in private fleets.
- Federal Motor Vehicle Control Program

The analysis of these measures found:

With the exception of the anti-idling program, the programs listed above have been in place for well over a decade and are working to reduce motor vehicle emissions under extreme winter operating conditions.

Measures focused on reducing traffic congestion offer limited benefits as the Fairbanks road network has few roads operating at Level of Service (LOS) levels D, E, or F.

Community-wide ridesharing programs offer few potential emission reduction benefits because of the low population and employment density in the nonattainment area (employer programs are operated where sufficient density supports participation).

Travel reduction programs have been found to have limited benefits on a national basis, with principal reductions coming from commute trips, which require high density employment to be successful.

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EPA's motor vehicle emissions model MOVES, including the recently released version MOVES2014b, does not provide a PM benefit for either light- or heavy-duty I/M programs. Thus, there is no way to quantify a particulate benefit from I/M, and EPA clearly does not recognize I/M as an appropriate PM control measure.

This resulted in a finding that no additional TCMs appear viable for Fairbanks. Because TCMs are not expected to provide additional reductions, all TCMs are classified as "not technologically feasible."

EPA comments on this measure were limited to inspection/maintenance (I/M) programs and vehicle idle restrictions (which were addressed separately in Measure 60). With regard to I/M, EPA commented that the finding that I/M is technologically infeasible because MOVES2014b is not a valid conclusion. They noted that the Utah Cache Valley has a I/M program for VOC and Fairbanks had previously operated an I/M program for carbon monoxide (CO) and this measure needed to be evaluated.

Analysis

The Borough Transportation Department[131] provided the following update of trends in transportation activities since the submission of the Moderate SIP:

- Expanded availability of plug-ins; electrical outlets continued to be installed on parking spaces with new projects at the Carlson Center, Big Dipper Ice Arena and both public libraries have been completed. These are joint projects between DOT and FNSB and are funded in FFY17 and FFY18 in the FMATS 2017 – 2020 TIP.[132]
- Adoption of an ordinance mandating—for employers with 275+ parking spaces—electrification of outlets at temps < 21° F between November 1 and March 31, this requirement is listed in current FNSB Code[133] for the Vehicle Plug-in Program.
- Public education is focused on the benefits of plugging-in and using the transit program called Metropolitan Area Commuter System (MACS) – an outreach program continues to provide this information
- Transit ridership in Fairbanks has been flat the past 3 years where national trends have been decreased ridership.
- Van Tran ridership in Fairbanks has closely followed fixed route ridership. However, the past year ridership has increased about 40% due to providing trips for Parks and Recreation participants

[131] Email from Glenn Miller, FNSB to Bob Dulla, Sierra Research, entitled Transportation Update, 1/23/18

[132] http://fmats.us/wp-content/uploads/2017/06/2017-2020-TIP-Admin-Mod-1-Revised.pdf

[133] http://www.codepublishing.com/AK/FairbanksNorthStarBorough/#!/FNSBC21/FNSBC2124.html#21.24

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- Anti-idling program for heavy-duty diesel vehicles started as a ADOT&PF program focused on dump trucks and tractors and has been expanded to a CMAQ-funded pilot program focused on the purchase and installation of auxiliary heaters to reduce idle time in private fleets. It is funded in FFY17 in the FMATS 2017 – 2020 TIP.[134]

FMATS has indicated[135] that VMT levels in Fairbanks continue to grow at 1.5% year over its long-range planning horizon through 2040, well below the national average. This supports the earlier finding that:

- *Measures focused on reducing traffic congestion offer limited benefits,*
- *Community-wide ridesharing programs offer few potential emission reduction benefits, and*
- *Travel reduction programs offer limited benefits.*

Finally, the latest version of EPA's Motor Vehicle Emissions Simulator MOVES2014b continues to show no $PM_{2.5}$ benefits for either light- or heavy-duty I/M programs. Thus, there is no way to quantify a particulate benefit from I/M, and EPA clearly does not recognize I/M as an appropriate $PM_{2.5}$ control measure.

With regard to EPA's comment about the need to assess the VOC benefits of an I/M program, the Moderate precursor analysis[136] and the 2019 update contained in the Modeling Chapter found that neither VOC nor NOx are significant precursor pollutants in the Fairbanks $PM_{2.5}$ nonattainment area. Thus, there is no technical basis to pursue an assessment of the costs and benefits of a I/M program for either VOC or NOx.

Conclusion

Findings for the transportation controls examined in the RACM analysis have not changed, these measures are technologically infeasible and not eligible for BACM.

Measure R29: Increase Coverage of the District Heating System

Implementing Jurisdiction(s)

- Fairbanks North Star Borough

Regulation Weblink(s)

- None

Background

[134] http://fmats.us/wp-content/uploads/2017/06/2017-2020-TIP-Admin-Mod-1-Revised.pdf
[135] Analysis of Interim 2045 MTP Interim Travel Model Runs provided by Kittelson and Associates, January 12, 2018.
[136] http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip-development

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Many residential, commercial, and institutional buildings within downtown Fairbanks are connected to a district heating system that supplies low pressure steam or hot water for space heating and domestic hot water use. Use of the district heating systems allows for the widespread use of energy produced by a central steam generating unit with effective emissions controls. These systems essentially eliminate the need for the operation of individual fuel combustion heating units in each of the facilities receiving heat from a central plant.

Even considering transmission losses, a well maintained and operated central heating facility can be much more efficient than individual combustion units, especially those that burn wood, coal, or oil. Emissions from a central facility are released into the atmosphere at a much greater height above grade than those of combustion units in individual buildings and, as a result, disperse more widely.

Aurora Energy operates a coal-fired cogeneration power plant that recycles low pressure steam for district heating use. Aurora Energy provides district heating (in the form of low-pressure steam or hot water) to approximately 180 customers. Customers range in size from small residential to large commercial/institutional loads.

Analysis

Aurora commissioned a study[137] in 2008 to examine the feasibility of expanding the underground network of pipes that deliver steam and hot water. Based on the information presented in that study, the RACM analysis determined this measure to be technologically feasible. Aurora provided updated heating expansion cost information in 2018.[138]

Conclusion

No information has become available to change the RACM analysis conclusion about the technological feasibility of this measure; therefore, this measure is technologically feasible and eligible for consideration as BACM or MSM.

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[137] PDC, Inc. Engineers, *Aurora Energy District Heat Capacity Study, Phase 2*, December 2008
[138] Email from Matt Burdick, PE, Project Engineer, Aurora Energy to Bob Dulla, Trinity Consultants, October 12, 2018

5. Step 4 – Determine Whether an Available Control Technology or Measure is Economically Feasible

EPA guidance[139] on determining the economic feasibility of technically feasible control measures was followed to calculate the cost per ton of pollutant reduced. Key cost information collected to support the preparation of the $/ton calculation included:

- Material/equipment prices (local purchase price, etc.)
- Labor (inspection, installation, maintenance, etc.)
- Program costs associated with implementing new control measures (including staff, software development, overhead, etc.)
- Maintenance costs (local labor and parts)
- Connection fees as appropriate (e.g., trenching, parts, etc.)
- Useful life – ranged between 8 and 30 years depending on the device lifespan
- Capital recovery rate – assumed to be 5.5%
- Existing fuel prices (documented by the Fairbanks Community Planning Department)
- Distillate fuel price forecasts (using EIA Pacific Region forecasts)
- Impact of market shifts on home heating fuel supply costs contained in the Appendix to Chapter 7
- Energy content of heating fuels (based on fuel sold in the Borough and reported by local suppliers)
- Combustion efficiency changes associated with the implementation of selected control measures
- Changes is home heating activity associated with measures addressing curtailment
- Changes in NOASH permits
- Changes in heating systems incorporated into new homes

The above information was used to calculate the annualized cost of operating current heating devices and the annualized cost of implementing individual measures for those devices consistent with the assumptions employed in the 2019 emissions inventory. A summary of the cost per ton of $PM_{2.5}$ reduced for each of the technically feasible measures is presented below in Table 9. The results indicate that only one of the technically feasible measures is cost effective, a shift from No. 2 to No. 1 home heating oil, the rest of the measures are not cost effective and have not been selected for implementation. A requirement mandating the shift in home heating oil has been incorporated into 18 AAC 50.078(b).

[139] Federal Register/Vol. 81, No. 164, August, 24, 2016, page 55805

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Table 9. Assessment of Economic Feasibility for Technically Feasible Control Measures (Cost Effectiveness Estimate)

Measure #	Measure Description	$/ton of $PM_{2.5}$ Reduced
51a.	No. 2 to No. 1 home heating oil	-3,698,299
51b.	No. 1 to ULS home heating oil	25,765
52	Operation and sale of small "pot burners" prohibited	1,371,455
53	No sale or exchange of used oil for fuel unless it meets constituent property limits	18,308,596
R29	Increase coverage of the District Heating System	617,335
61	EPA – Fuel oil boiler upgrade – burner upgrade/repair	70,448,210
62	EPA – Fuel oil boiler upgrade - replacement	7,002,188

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6. Step 5 – Determine the Earliest Date by Which a Control Measure or Technology can be Implemented in Whole or in Part

The Step 3 technological feasibility analysis identified 40 separate measures the state is addressing through the adoption of new regulations. All of those measures are considered to be both technologically and economically feasible. The Step 4 economic feasibility analysis considered 6 separate measures and determined that only the Measure 51 shift from No. 2 to No. 1 home heating oil is economically feasible. A summary of the 41 control measures determined to be both technologically and economically feasible is listed in Table 10 below. While some of the regulations implementing portions of the measures are already in place and not displayed in the table, all of the measures are being implemented in whole or in part by new state regulations and in the Episode Chapter of the $PM_{2.5}$ Serious SIP. Those regulations are displayed along with the date of implementation in Table 10. As can be seen, all of the technologically feasible and economically feasible measures are to be implemented at the effective date of regulation.

Table 10. BACM Implementation Dates

Measure #	Measure Description	Enabling Regulation	Start Date
2	Prohibit advertising used devices that do not meet emission criteria for new device sales	18 AAC 50.077(k)(5)	Effective date of the regulation
3	Require building or other permit	18 AAC 50.077(k)(4)	Effective date of the regulation
4	Require confirmation of proper installation by requiring professional installation or on-site inspection	18 AAC 50.077(k)(2) & (3)	Effective date of the regulation
5	Register/require industry certification of heating professionals	18 AAC 50.077(k)(2) & (3)	Effective date of the regulation
7	Require devices meet stricter emission criteria in high pollution zones	18 AAC 50.077(c), (d), (e), (f), (g), (h), (i), (j)	Effective date of the regulation
13	Submit sale and installation Information to Air Program	18 AAC 50.077(d), (d)(3) & (k)(1)	Effective date of the regulation
15	Disclosure of devices on property sale	18 AAC 50.077(b), (k)(2), & (m)	Effective date of the regulation
16	Require notice and proof of destruction or surrender of removed, uncertified devices	18 AAC 50.077(b), (k)(2) & Episode Chapter	Effective date of the regulation

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Table 10. BACM Implementation Dates

Measure #	Measure Description	Enabling Regulation	Start Date
17	Require Removal of Uncertified Solid Fuel Burning Devices Upon Sale of Property	18 AAC 50.077(b)	Effective date of the regulation
19	Require registration of devices to qualify for exemption from curtailments	18 AAC 50.077(k)(1) & Episode Chapter	Effective date of the regulation
20	Require renewals with inspection requirements	18 AAC 50.077(k)(1) & Episode Chapter	Effective date of the regulation
21	Optional device registration for curtailment exemptions	18 AAC 50.077(k)(1) & Episode Chapter	Effective date of the regulation
22	Require registration of all devices	18 AAC 50.077(k)(1), 50.077(d), (e), (f), (g)	Effective date of the regulation
24	Require permanent Installed Alternative Heating Method in Rental Units	18 AAC 50.077(k)(4)	Effective date of the regulation
25	Require detailed application or inspection to verify need	Episode Chapter	Effective date of the regulation
26	Require inspection of devices and installation	18 AAC 50.077(k)(2) & (3).	Effective date of the regulation
27	Require annual renewal of waiver	Episode Chapter	Effective date of the regulation
28	Set income threshold	Episode Chapter 18 AAC 70.077(b)	Effective date of the regulation
29	Allow only NOASH households to burn during curtailment periods	Episode Chapter	Effective date of the regulation
30	Distribution of Curtailment Information at Time of Sale of Wood-Burning Device	18 AAC 50.077(k)(1)	Effective date of the regulation
31	Require sale of only dry wood during late summer to end of winter	18 AAC 50.076(j) & 18 AAC 50.078(e)	Effective date of the regulation
32	Require dry wood to be clearly labeled to prohibit marketing of non-dry wood as dry wood; Distribution of Information Related to Moisture Content at Time of Wood Sale	18 AAC 50.076(j) & 18 AAC 50.078(e)	Effective date of the regulation
40	Single Stage Curtailment	Episode Chapter	Effective date of the regulation
42	Burn down period	18 AAC 50.075(e)(3)	Effective date of the regulation

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Table 10. BACM Implementation Dates

Measure #	Measure Description	Enabling Regulation	Start Date
48	Date certain removal of "coal only heater"	18 AAC 50.079(f) 18 AAC 50.077 (k)(2)	Effective date of the regulation
49	Prohibit use of coal burning heaters	18 AAC 50.079(f)	Effective date of the regulation
51	Shift from # 2 to #1 heating oil	18 AAC 50.078(b)	Effective date of the regulation
65	Emissions crossing property lines	18 AAC 50.075(f)(2)	Effective date of the regulation
66	Lower curtailment threshold	Episode Chapter	Effective date of the regulation
67	Coffee Roasters - Commercial	18 AAC 50.078(d)	1-yr after the effective date of the regulation
68	Charbroilers - Commercial	18 AAC 50.078(c)	Effective date of the regulation
69	Incinerators - Commercial	18 AAC 50.078(c)	Effective date of the regulation
70	Used oil burners	18 AAC 50.078(c)	Effective date of the regulation
R4	All units must be certified	18 AAC 50.077(b)	Effective date of the regulation
R5	Ban new installations - hydronic heaters	18 AAC 50.077(b), (c), (d) & (k)(2)	Effective date of the regulation
R6	Remove hydronic heaters at time of home sale	18 AAC 50.077(b)	Effective date of the regulation
R9	All wood stoves must be certified	18 AAC 50.077(b)	Effective date of the regulation
R10	Replace uncertified units at time of sale	18 AAC 50.077(b)	Effective date of the regulation
R11	Replace uncertified units at time of significant remodeling	18 AAC 50.077(b)	Effective date of the regulation
R12	Replace uncertified stoves in rental units	18 AAC 50.077(b)	Effective date of the regulation
R16	Disincentives to sell used stoves	18 AAC 50.077(b), (e), (f) & (k)(2)	Effective date of the regulation

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7. BACM Findings

The BACM analysis considered 81 separate control measures. The disposition of those measures is as follows:

- 25 – dismissed as infeasible because their adoption would produce no emission benefits;
- 40 – addressed through the adoption of new state regulations and therefore technologically and economically feasible;
- 10 – to be addressed in a subsequent SIP as MSM, and
- 6 – determined to be technologically feasible and assessed for economic feasibility; 1 of the 6 was determined to be economically feasible.

The result is that a total of 41 measures were selected as BACM. The selected measures address a wide range of space heating, area source, commercial source and transportation activity categories represented in emissions inventory. While this document has not quantified the benefits of all of the selected measures, their implementation will substantially reduce directly emitted $PM_{2.5}$ and related precursor emissions and aid community/state efforts to achieve attainment of the ambient 24-hour $PM_{2.5}$ standard.

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Appendices

A copy of the state's report entitled *Residential Fuel Expenditure Assessment of a Transition to Ultra-Low Sulfur and High Sulfur No. 1 Heating Oil for the Fairbanks PM-2.5 Serious Nonattainment Area* is contained in the Appendix III.D.7 Control Strategies of the $PM_{2.5}$ Serious SIP.

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By: Leah Berman Williams
Marna Sanford
Shaun Tacke
Liz Lyke
Introduced: 03/14/2019
Adopted: 03/14/2019

FAIRBANKS NORTH STAR BOROUGH

RESOLUTION NO. 2019 – 08

A RESOLUTION SUPPORTING LEGISLATION GRANTING THE ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION, DIVISION OF AIR QUALITY THE AUTHORITY TO ISSUE CIVIL FINES FOR VIOLATIONS IN AREAS CLASSIFIED AS SERIOUS NONATTAINMENT AREAS

WHEREAS, The United States Environmental Protection Agency (EPA) in December 2009, declared part of the Fairbanks North Star Borough (Borough) a non-attainment area for fine particulate pollution (PM2.5); and

WHEREAS, On December 16, 2016 the EPA published public notice in the Federal Register of its intent to reclassify the Borough non-attainment area from Moderate to Serious status, and the Final Rule was signed on April 28, 2017; and

WHEREAS, A coalition of community partners assembled an Air Quality Stakeholders Group to identify, evaluate and recommend community based solutions to bring the area into compliance with federal air quality standards for fine particulates ($PM_{2.5}$); and

WHEREAS, One of the recommendations of the Air Quality Stakeholders Group is that legislation be adopted granting the Alaska Department of Environmental Conservation (ADEC) administrative penalty authority in order to ensure compliance with and enforcement of state laws and regulations; and

WHEREAS, The ability to impose a civil fine in an area classified as a serious nonattainment area or to meet provisions adopted within a State Air Quality Control Plan is a much needed component of an effective curtailment program.

NOW THEREFORE BE IT RESOLVED that the Assembly of the Fairbanks North Star Borough supports legislation granting the Alaska Department of Environmental Conservation, Division of Air Quality the authority to issue civil fines for violations in areas classified as serious nonattainment areas.

BE IT FURTHER RESOLVED that a copy of this resolution shall be delivered to Governor Michael J. Dunleavy, the members of the Alaska Senate, and the Alaska House of Representatives.

PASSED AND APPROVED THIS 14TH DAY OF MARCH 2019.

Angela Major, Deputy
Presiding Officer

ATTEST:

April Trickey, CMC
Borough Clerk

Yeses: Williams, Quist, Tacke, Sanford, Lyke, Major
Noes: Lojewski
Other: Gray (Excused), Cooper (Excused)

Northeast State for Coordinated Air Use Management (NESCAUM)

Studies on Catalyst vs Non-Catalyst Woodstove

2017 partial Results of the Comparison of Emission Profiles of Catalyst vs Non-catalyst Woodstove using EPA Method 28 Combined with Tapered Element Oscillating Microbalance (TEOM) during the Hi, Low, and Medium Fire

Preliminary Data Comparing Replicates from Catalytic/Hybrid Appliance and Non-Catalytic Appliance using the Integrated Duty Cycle (a cord wood test under development)

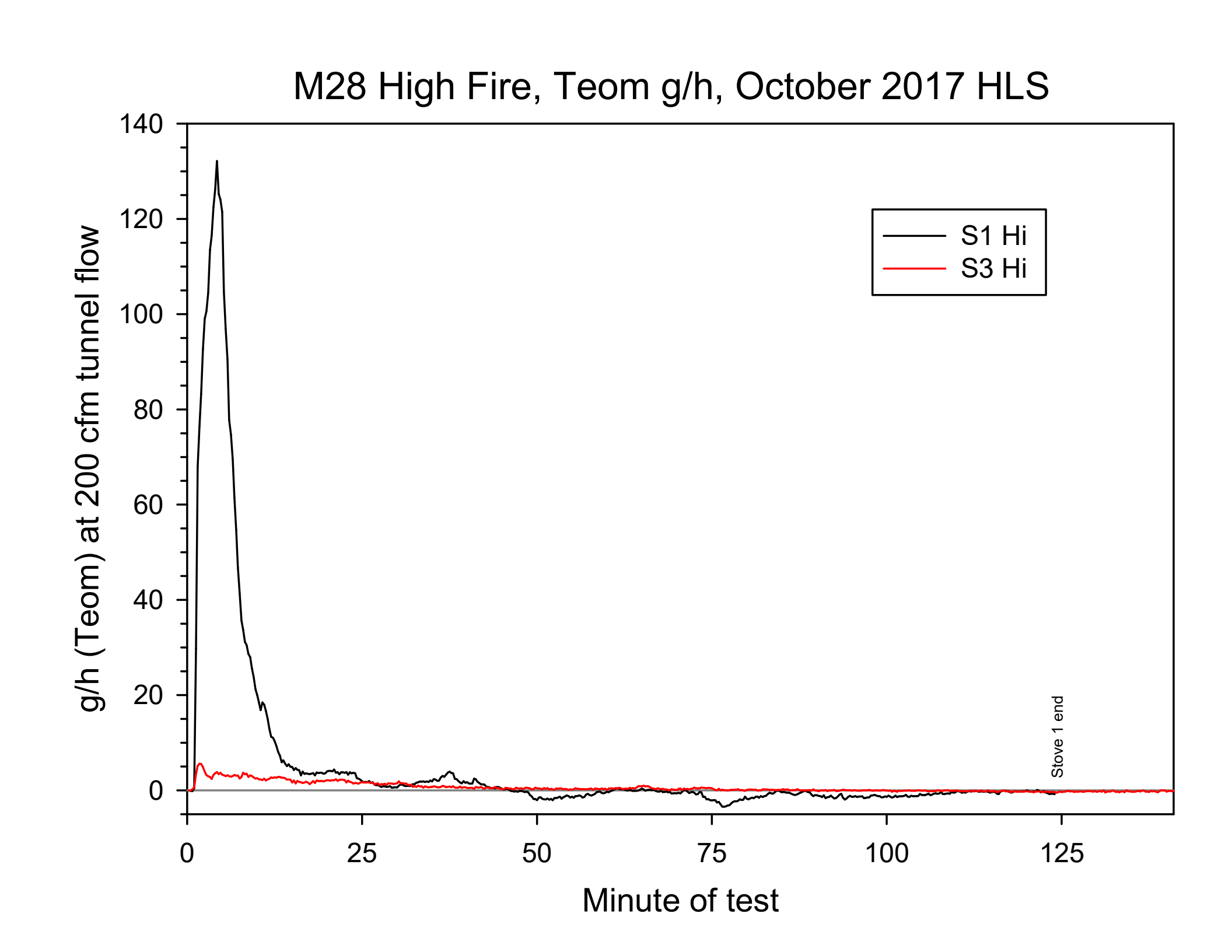
NESCAUM
Northeast State for Coordinated Air Use Management

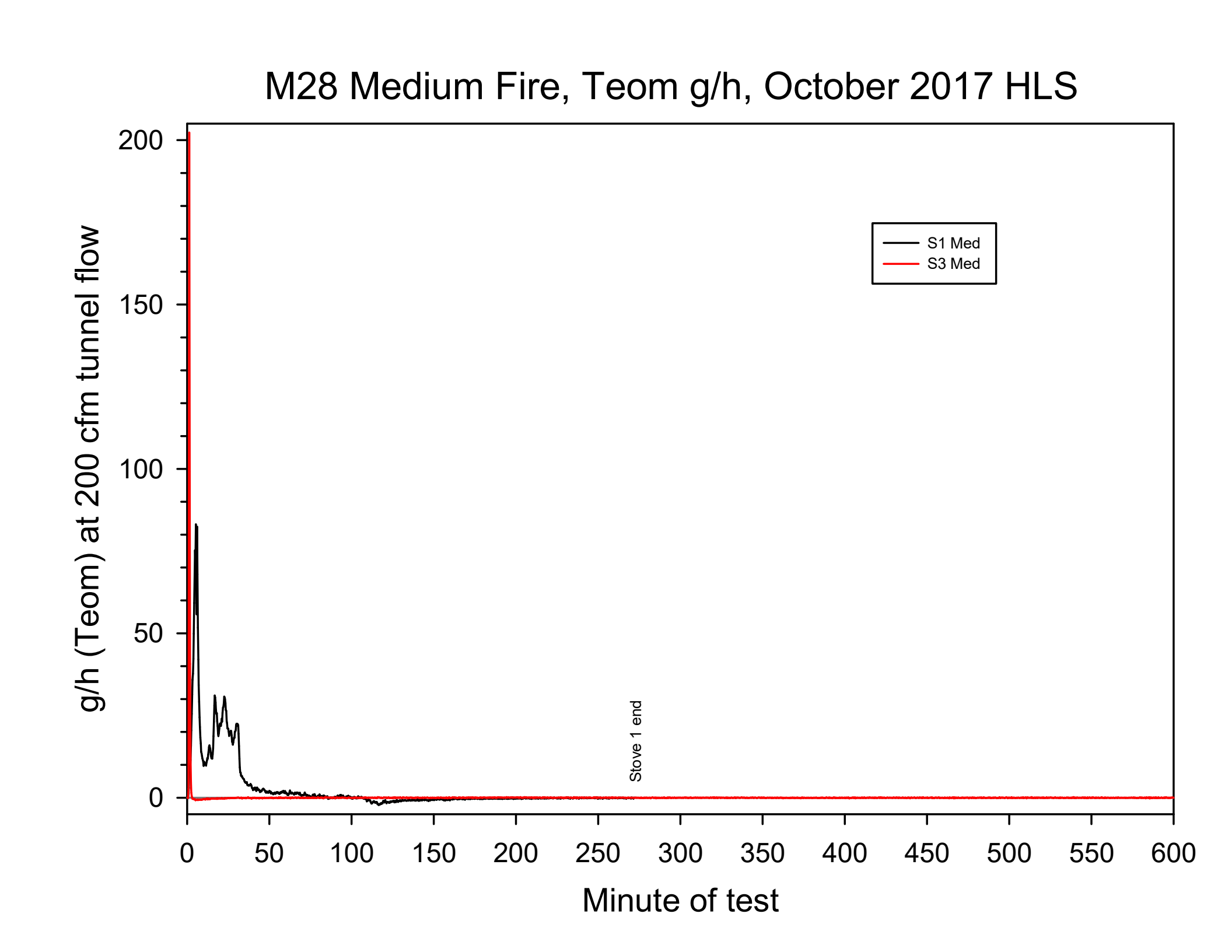
2017 partial results

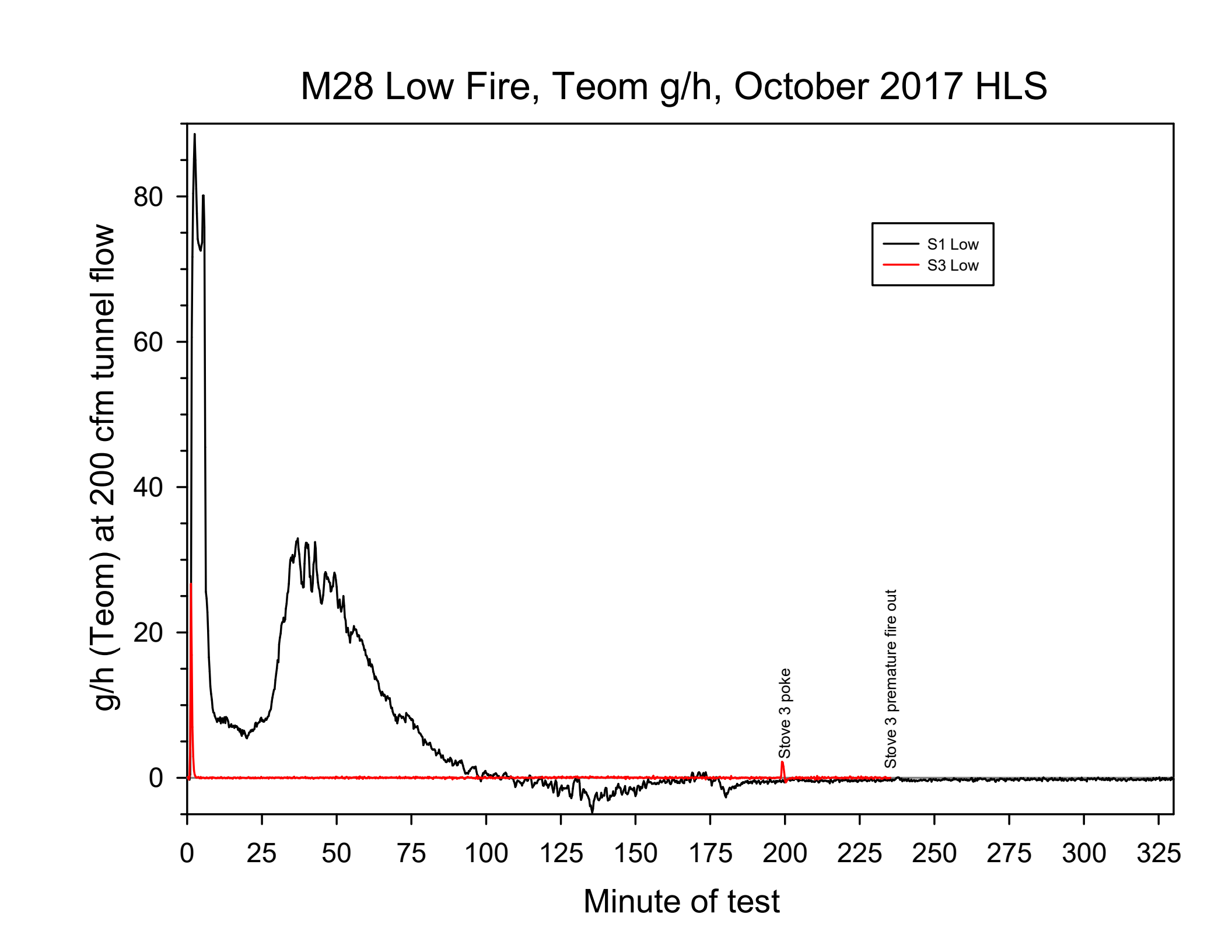
Comparison of Emission Profiles

Catalyst vs Non-Catalyst Woodstove

Using EPA Method 28 combined with tapered element oscillating microbalance (TEOM)
during the Hi, Low, and Medium Fire


M28 High Fire, Teom g/h, October 2017 HLS
g/h (Teom) at 200 cfm tunnel flow
140
120
100
80
60
40
20
0
0
25
50
75
100
125
Minute of test
S1 Hi
S3 Hi
Stove 1 end


M28 Medium Fire, Teom g/h, October 2017 HLS
g/h (Teom) at 200 cfm tunnel flow
Minute of test
S1 Med
S3 Med
Stove 1 end
0
50
100
150
200
250
300
350
400
450
500
550
600


M28 Low Fire, Teom g/h, October 2017 HLS
g/h (Teom) at 200 cfm tunnel flow
Minute of test
S1 Low
S3 Low
Stove 3 poke
Stove 3 premature fire out
0
20
40
60
80
0
25
50
75
100
125
150
175
200
225
250
275
300
325

TO: Cindy Heil, Alaska DEQ

FROM: Lisa Rector, NESCAUM

DATE: May 6, 2019

RE: Preliminary data comparing replicates from Catalytic/Hybrid Appliance and Non-catalytic appliance

Per your request, I am providing you with preliminary data from our stove testing efforts. There will be additional data available to support this information later this year. The table below reflects the results of replicate tests using several different species with two stoves. Both stoves have the same firebox size, however, the stoves employ two different control technologies. Stove 6 is a non-catalytic stove and Stove 7 is a stove that employs both catalytic and non-catalytic controls. The testing protocol used the Integrated Duty Cycle (IDC) operational and fueling protocol, which are available at: https://www.nescaum.org/topics/test-methods

The graph below represents 9 IDC test runs on Stove 6, and 12 IDC test runs on Stove 7 using the following fuels:

- Stove 6:
  - Three replicate tests with red maple cordwood, average MC = 21.1%
  - Three replicate tests with seasoned oak cordwood, average MC = 21.4%
  - Three replicate tests with wet oak cordwood, average MC = 28.1%
- Stove 7:
  - Three replicate tests with red maple cordwood, average MC = 20.4%
  - Three replicate tests with seasoned oak cordwood, average MC = 21.2%
  - Three replicate tests with wet oak cordwood, average MC = 28.7%
  - Three replicate tests with poplar cordwood, average MC = 20.8%

The chart highlights the variability in testing results for each test phase and the overall run. Load 1 is the start-up load, kindling, start-up fuel and smaller fuel pieces loaded at a loading density of 7 pounds per cubic foot with air settings at high load and low load. Load 2 represents fire maintenance mode, which loads two large pieces on the stove at loading density of five pounds per cubic foot and set at low air settings. Load 3 represents an overnight load where the stove is filled with as much fuel as possible and set at low air settings. The final chart represents the results from the from the entire test run from Load 1 to Load 3. The charts represent results in both terms of emissions rates – figure 1 (grams per hour) and emission factor – figure 2 (grams per kilogram).

Data gathered to date suggests that they hybrid unit has significantly less variability from run to run and even when moving from species. Stove 6 replicate runs show significantly variability when running replicates, which is not seen on Stove 7. Stove 6 also shows sensitivity to variations in fuel types, which is not observed on Stove 7. Stove 7 exhibits a slightly higher emission factor when comparing test results between oak with two moisture contents, which is likely due to lower burn rates since the change is not detected in the emission rate data.

Please note that this is preliminary data and a complete analysis of protocol, stove and species will be completed in the final project report.

Figure 1. IDC comparison Stove 6 (Non-Catalytic) & Stove 7 (hybrid) – Grams per Hour

Preliminary data – full analysis will be available with final project report.

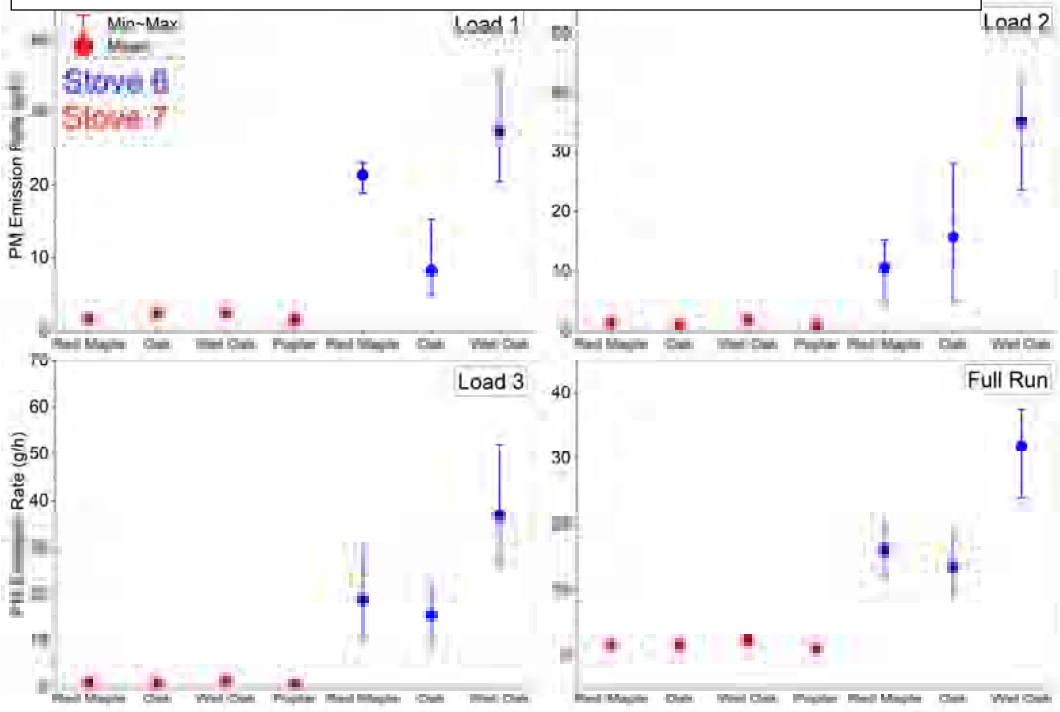
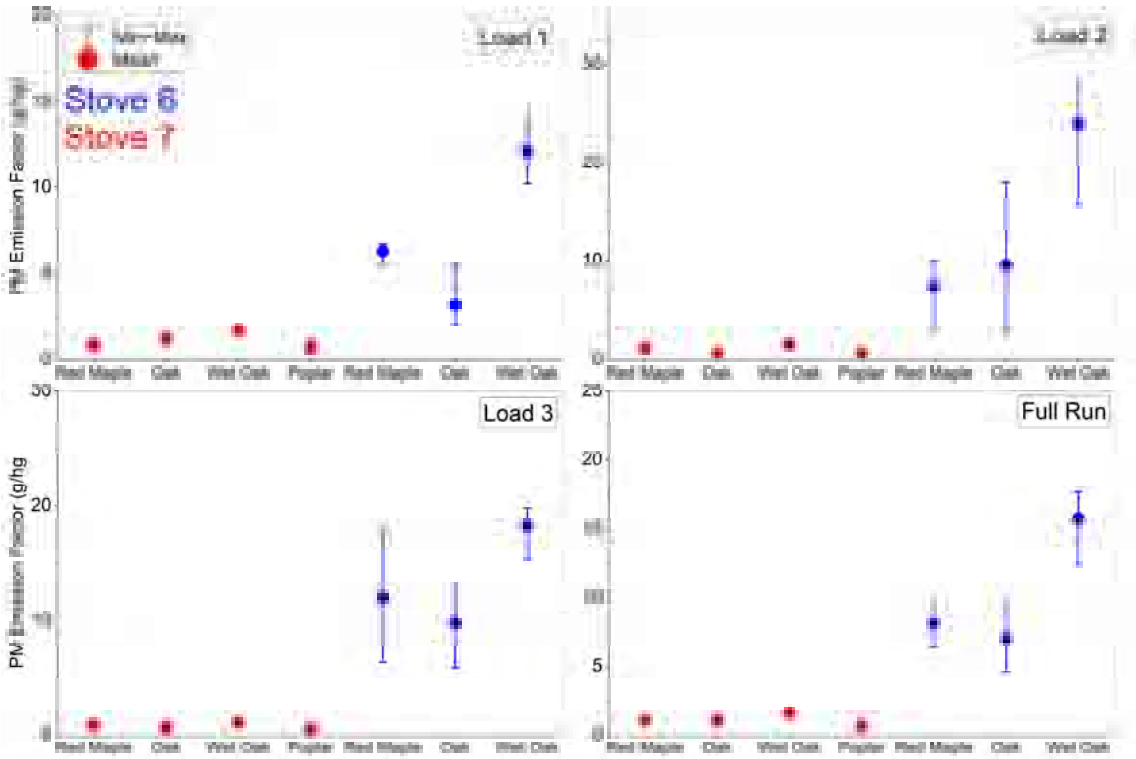


Figure 2. IDC comparison Stove 6 (Non-Catalytic) & Stove 7 (hybrid) – Grams per Kilogram

Preliminary data – full analysis will be available with final project report.



Alaska Department of Environmental Conservation

Public Comment Draft

Residential Fuel Expenditure Assessment of a Transition to Ultra-Low Sulfur and High Sulfur No. 1 Heating Oil for the Fairbanks PM-2.5 Serious Nonattainment Area

February 2019

Prepared by

The Alaska Department of Environmental Conservation Economist in collaboration with the University of Alaska Fairbanks Master of Science Program in Resource and Applied Economics.

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Abbreviations

ADEC	Alaska Department of Environmental Conservation
BACM	Best Available Control Measure
BTU	British Thermal Unit
EIA	US Energy Information Agency
EPA	US Environmental Protection Agency
FNSB	Fairbanks North Star Borough
HS	High Sulfur
NPV	Net Present Value
OPIS	Oil Price Information Service
PM	Particulate Matter
PSI	Petro Star, Inc.
SIP	State Implementation Plan
ULS	Ultra-Low Sulfur

Executive Summary

In September 2017, the Alaska Department of Environmental Conservation (ADEC) Division of Air Quality requested the ADEC Economist to facilitate a research project regarding the evaluation of possible economic impacts of a potential PM-2.5 pollution control policy mandating a transition to ultra-low sulfur (ULS) heating oil in the Fairbanks PM-2.5 Serious Nonattainment Area. The ADEC Economist worked on this research together with the University of Alaska, Fairbanks Master of Science Resource and Applied Economics Program Director and graduate students. The initial report was released in March 2018 and evaluated the possible changes in home heating fuel expenditures for Fairbanks residents given a hypothetical requirement imposing a transition to ULS heating fuel.

Upon receiving feedback on the March 2018 draft, this report has been updated to address the comments received from the public and the United States Environmental Protection Agency (EPA). In July 2018, the ADEC purchased new data to update the fuel prices used in the analysis. In the fall of 2018, additional policy analysis of a potential high sulfur (HS) No. 1 heating oil mandate was completed. This content has been added to provide information on the expenditure effects of a HS No. 1 use requirement for a typical Fairbanks household. A summary of the energy content of each fuel type, and a discussion regarding sulfur reduction and its effect on energy (BTU) content is included in *Section II.* This updated final report is the outcome of the research conducted by ADEC and the University of Alaska Fairbanks.

Below is a summary of key findings from each section of the analysis.

Section I: Fuel Costs

Important findings from the review of the incremental ULS price differentials[1], the additional cost to purchase ULS over HS, for both Anchorage and Fairbanks wholesale markets, as well as purchasing Fairbanks HS No. 1 over HS No. 2 include:

- Since 2008-2010, the ULS price differential in Alaska has decreased significantly.
- From April 2017 to July 2018[2] the ULS No. 1 to HS No. 1 monthly price differentials for Anchorage range from 3 to 42 cents/gallon.
- The average ULS No. 1 to HS No. 1 price differential for Anchorage is 23 cents/gallon, representing an 11% price increase.
- Fairbanks ULS is more expensive than Anchorage, reflecting additional transport costs.
- The ULS No. 1 to HS No. 1 monthly price differentials for Fairbanks range from 16 to 54 cents/gallon over the 16 months evaluated.
- The average ULS No. 1 to HS No. 1 price differential for Fairbanks is 34 cents/gallon, representing a 15% increase.
- In Fairbanks, there is a larger ULS price differential between ULS No. 1 to HS No. 2 than ULS No. 1 to HS No. 1, as HS No. 2 tends to be cheaper relative HS No. 1.

[1] All price differentials are listed in the summary have rounded to the nearest cent.
[2] This is the 16-month time frame evaluated. All 16-month average figures listed are calculated using OPIS price data from April 2017 through July 2018.

- The average Fairbanks HS No. 1 to HS No. 2 price differential ranges from 5 to 10 cents/gallon using a 16-month time-period.
- The ULS No. 1 to HS No. 2 monthly price differentials for Fairbanks range from 21 to 59 cents/gallon over the 16 months evaluated.
- The average ULS No. 1 to HS No. 2 price differential for Fairbanks is 41 cents/gallon, representing a 19% increase.

Section II: Household Expenditure Cost Scenarios Analysis

Important findings from the analysis of how a hypothetical shift to more expensive ULS or HS No. 1 fuel would affect household heating expenditures for Fairbanks residential households include:

- Based on the survey data collected from 2011-2015, approximately 80% of respondent households reported having a central oil heating appliance in the household.[3]
- 40% of surveyed households reported using a central oil heating appliance with no other reported appliances. Households using a central oil boiler with no other appliances reported using an average of 1,230 gallons of fuel oil.[4]
- This analysis is on the short run effects of HS to ULS, and the HS No. 2 to HS No. 1 fuel transition, highlighting the price insensitivity of household heating for FNSB residents compared to long run effects.
- Price differentials of 34 and 41 cents/gallon were used to represent the difference between HS and ULS fuel prices.
- A price differential of 7 cents/gallon is used to represent the difference between Fairbanks HS No. 1 and HS No. 2 fuel prices.
- Average household expenditures on heating energy is $2,274 annually.[5]
- Using price differentials of 34 and 41 cents/gallon, an average annual fuel usage of 1,230[6] - 50% of FNSB households would see an expected expenditure increase of $311.96 or $374.86, respectively for the first year of a shift to ULS fuel.[7]
- Estimates represent a 14% to 17% increase in household heating expenditures in the first year.
- Using a price differential of 7 cents/gallon, - 50% of households would see an expected expenditure increase of $68.31 for the first year of a switch to HS No. 1.
- This estimate represents a 3% increase in household heating expenditures in the first year.
- ULS Monte Carlo Analysis results, using a constant fuel price of $2.10, estimate that the average annual increase in household heating expenditure is $329.73.

[3] (Sierra Research Inc., 2015)
[4] (Sierra Research Inc., 2015)
[5] Section 2.2 Heating Oil Cost Models
[6] Fuel usage for central oil only homes is 1,230 gallons annually
[7] Assumed own-price elasticity of -0.2 is used for all modeled scenarios. The assumed rate of -0.2% is drawn from a study of home heating fuel demand conducted by Hirst, Goeltz, & Carney (1982) and implies that a 1% increase in the price of home heating oil will decrease the quantity demanded by 0.2%.

- This ULS Monte Carlo estimate represents a 15% increase in household expenditures in the first year.
- Based on the distribution of the Monte Carlo estimates, 90% of households are predicted to incur additional expenditures of $650 or less in the first year given a switch to ULS.
- HS No. 1 Monte Carlo Analysis results, using a constant fuel price of $2.10, estimate the average annual increase in household heating expenditure is $84.32.
- This HS No. 1 Monte Carlo estimate represents a 4% increase in household heating expenditures in the first year.
- Based on the distribution of the Monte Carlo estimates, 90% of households are predicted to incur additional expenditures of $160 or less in the first year given a switch to HS No. 1.
- ULS Monte Carlo results verify the estimates of an expected expenditure increase of $311.96 or $374.86, respectively, for the first year as the mean estimations fall within this range.
- HS No. 1 Monte Carlo results fall slightly outside the expenditure increase estimate with a mean calculated expected expenditure increase of $84.32, the median estimates are closer to the original estimate of $68.31 with an expected annual expenditure increase of $76.12.

Introduction

In December of 2009, the EPA designated Fairbanks as a Serious Nonattainment Area for Particulate Matter (PM)-2.5 emissions for the 2006 24-hour air quality standards. The Fairbanks North Star Borough (FNSB) has recorded some of the highest levels of PM-2.5 in the United States. The largest contributors to PM-2.5 in the FNSB are wood stoves and hydronic heaters.[8] Currently, two of the measures implemented to mitigate PM-2.5 emissions are requiring a removal of inefficient wood heating devices when a property is sold or leased[9] and requiring commercial wood sellers to register with the state and report the moisture content of wood they are selling to residential wood-burners.[10]

When EPA reclassified the Fairbanks PM-2.5 Nonattainment Area from a Moderate to Serious designation, it prompted the requirement for ADEC to conduct a Best Available Control Measure (BACM) analysis. The BACM analysis looks at control measures implemented throughout the United States in State Implementation Plans to control PM-2.5. This analysis was conducted as a part of the BACM process. This report provides information on potential changes in residential home heating expenditures in the Fairbanks PM-2.5 Nonattainment Area given hypothetical requirements to switch to different types of heating oil. *Section I* evaluates the fuel cost difference between ultra-low sulfur (ULS) and current heating fuels – high sulfur (HS) No. 1 or No. 2 – and the cost difference between HS No. 1 and HS No. 2. *Section II* assesses how price differences found between fuels would affect household heating expenditures for the typical FNSB household.

This report presents two evaluations of possible changes to household expenditures, the first which may arise from a conversion to ULS heating oil, and the second from HS No. 2 to HS No. 1. The analysis does not address any potential changes in household preferences and behaviors regarding home heating, nor does the assessment address other economic impacts which may arise from possible transition.[11] The modeled scenarios developed for *Section II* to determine potential changes to fuel price expenditures may be adapted to address other questions regarding direct fuel cost expenditure impacts to FNSB households. This model is an additional tool outside of this report and can be adapted to evaluate alternative price differentials, fuel usage quantities, and price elasticities.

[8] (U.S. Environmental Protection Agency, n.d.)
[9] Alaska State regulation. 18 AAC 50.077 and 18 AAC 50.079
[10] Alaska State regulation. 18 AAC 50.076(d)
[11] See Section 2.4 the Potential Benefits of a Switch to ULS for a further discussion of the potential benefits not captured in this expenditure analysis.

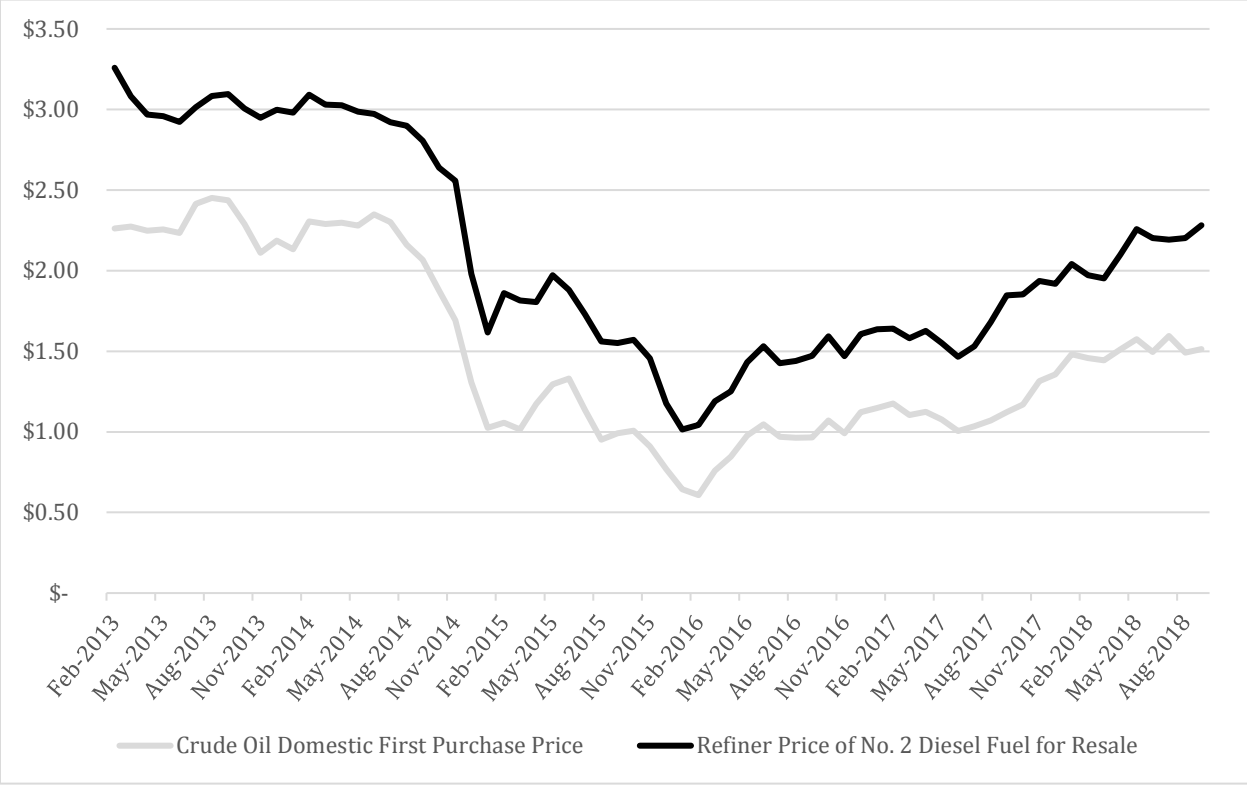
Section I: Fuel Costs

The purpose of this section is to estimate the cost effect of switching to ultra-low sulfur (ULS) heating oil, or to high sulfur (HS) No. 1 in the Fairbanks PM-2.5 Nonattainment Area. Estimates of the incremental price differences between the proposed ULS No. 1 and heating fuel products currently used, HS No. 1 and HS No. 2 are provided. These estimates were calculated by analyzing the Oil Price Information Service (OPIS) data to determine fuel cost differentials.

1.1 Fuel Cost Overview

Prior to the examination of ULS and Fairbanks HS No. 1 fuel prices, it is beneficial to review current distillate fuel price structures. The price of refined distillate fuels generally follows the price of crude oil, which is driven by the global market, weather, transportation, geopolitical, and economic factors. *Figure 1* provides a comparison of Crude Oil and Retail Diesel No. 2. This comparison depicts the price relationship between crude and refined fuels.

Figure 1: Crude Oil and Refined Diesel Prices, Dollars per Gallon



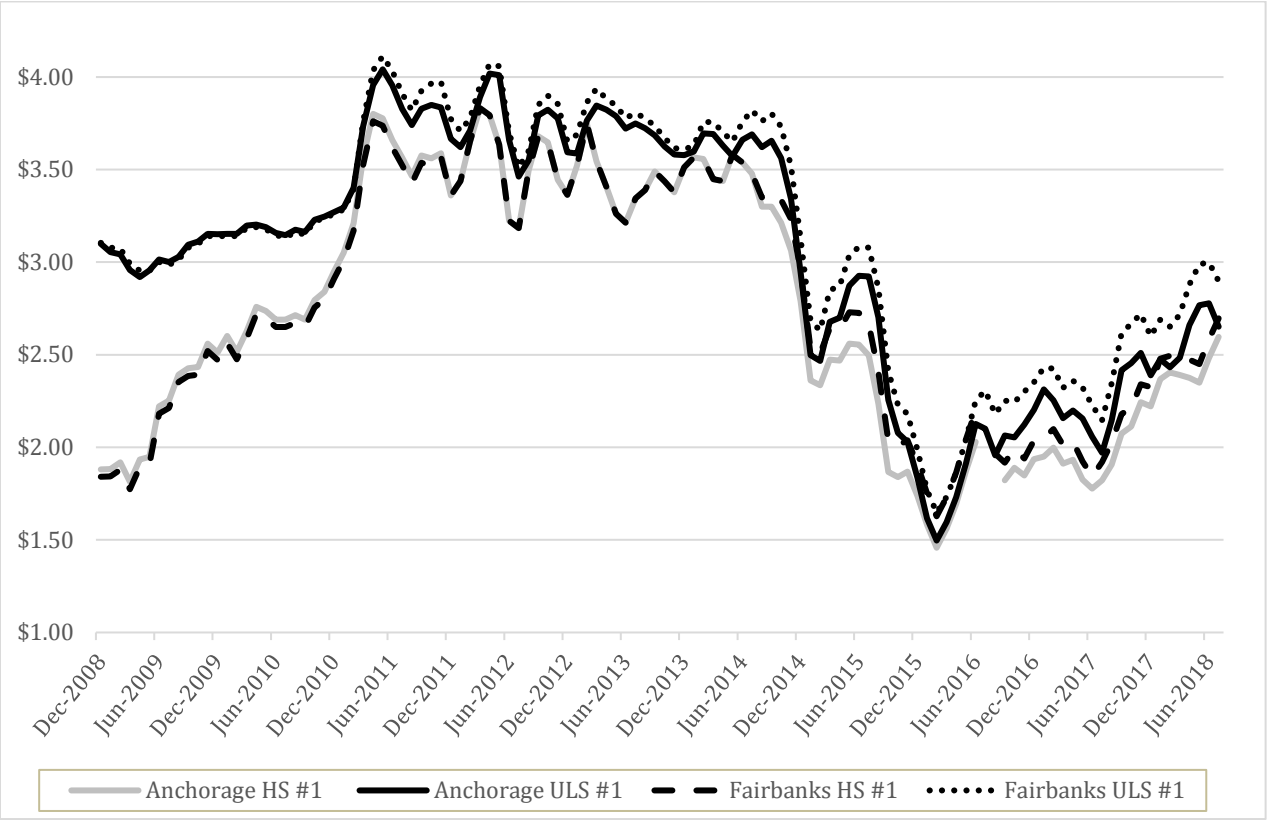
Source: Energy Information Administration (EIA), Energy Prices, September 2018[12]

[12] (EIA,2018) Crude Oil Prices "Crude Oil Domestic First Purchase Price" and (EIA,2018) "Refiner Price of No. 2 Diesel Fuel for Resale"

In recent years, there has been a significant drop in crude oil prices. This can be viewed holistically as a change in the global market influenced by a large-scale increase of US shale production (Institute for Energy Research, 2016).

Alaska is an isolated market with only five local refineries (two of which are in Prudhoe Bay and supply fuel for crude oil drilling operations). Even as prices for refined distillate fuels and heating fuels have fallen, in Alaska these prices are consistently above the national average. In addition, fuel prices are higher in Fairbanks than in Anchorage as fuel needs additional shipping to get to its destination (Northern Economics, 2007. p.15).

Figure 2: Alaska Fuel Price Comparison, Dollars per Gallon



Source: Alaska Department of Environmental Conservation, OPIS

Figure 2 presents the price of HS No. 1 in Anchorage, ULS No. 1 in Anchorage, HS No. 1 in Fairbanks, and ULS No. 1 in Fairbanks. These prices follow national market trends and reflect the price of crude oil. As a result, fuel prices in recent years are significantly lower than the 2011-2014 period.

One notable exception in Alaska is that the ULS Price Differential, the additional premium to purchase ULS over HS, has decreased significantly since 2008-2010. This can likely be attributed to increased ULS capacity, as new ULS capacity came online from Alaskan refineries. Beginning in 2008, Petro Star Inc. (PSI) invested $200 million to produce ULS at their Valdez

refinery. In 2007, Andeavor (formerly known as Tesoro) invested $63 million and from 2010-2014 an additional $189 million to manufacture ULS fuel (Econ One Research, Inc., 2015. p.3). In Fairbanks, ULS tends to be more expensive than Anchorage, which may be explained by additional transportation costs. Section 1.2 and 1.3 will explore the actual observed price differences in Fairbanks rack fuel prices over time and product type.

1.1.1 OPIS Fuel Price Data

The data reviewed consists of monthly non-weighted calendar day averages gathered by the Oil Price Information Service (OPIS). OPIS is the only provider of spot, rack, and retail prices for the United States. OPIS is known for having a defined methodology for the collection of fuel price data. Rack price data used represents market wholesale terminal prices (OPIS, 2018).

This analysis focuses on Fairbanks rack fuel prices unless otherwise noted. The data are evaluated in a static manner. Historical market prices are reviewed to estimate the incremental cost difference between fuel types.

All prices are listed in nominal terms and have not been adjusted for inflation. This price data does not include costs associated with taxes or final transportation from the wholesale terminal to the final user. A benefit of using OPIS data is that it represents the market price. The market price in economics is the price at which an asset is bought or sold. Utilization of this type of price data helps reflect the actual market price, which adds to the credibility of the price differential estimates presented.

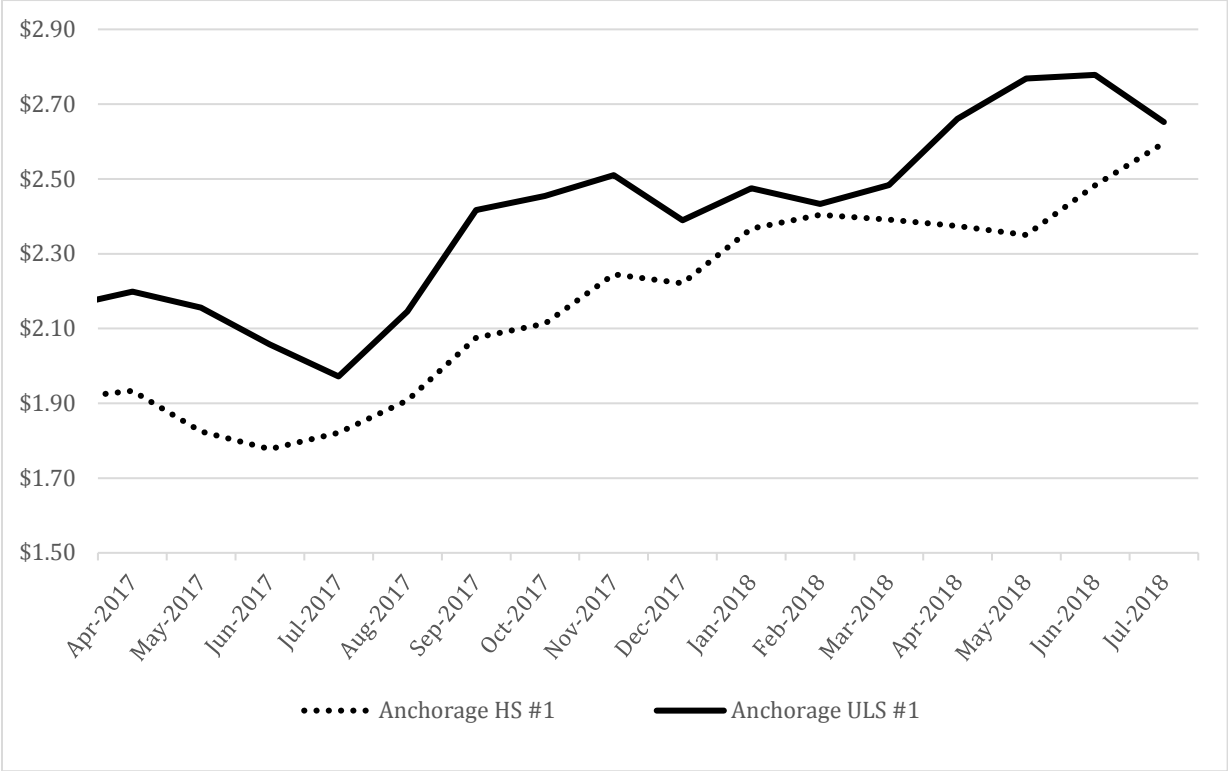
1.2 Fuel Cost Trends and Differentials

To develop estimates of the price difference between fuel types, a review of current pricing was conducted. The focus is a comparison of HS to ULS fuel prices and also a comparison of HS No. 2 to HS No. 1, as the hypothetical policy changes evaluated would require a transition to a fuel type that would fulfill EPA's sulfur content requirements for a PM-2.5 control measure. The purpose of this is to understand the cost difference between fuel types to gauge the potential fiscal impact on Fairbanks' households. A review of Anchorage prices is provided as background information should the purchase of Anchorage fuel and rail transport to Fairbanks be necessary.

Price data was evaluated by taking the non-weighted monthly average prices for Anchorage and Fairbanks, then calculating the price differentials between ULS and HS for each location. First, the fuel price differential between ULS No. 1 and HS No. 1 for Anchorage (*Table 1*) is detailed followed by the Fairbanks differentials. For Fairbanks, the price differential between both ULS No. 1 and HS No. 1 (*Table 2*), ULS No. 1 and HS No. 2 (*Table 3*), and HS No. 1 and HS No. 2 (*Table 4)* have been computed.[13]

[13] For the purpose of this analysis the fuel price differentials evaluated are individual fuel type price comparisons. There are uncertainties in the actual amount of mixed HS and ULS fuel in the heating oil products that are

Figure 3: Anchorage Distillate Cost Comparison, Dollars per Gallon



Source: Alaska Department of Environmental Conservation, OPIS

Figure 3 provides a visual representation of wholesale rack fuel prices in Anchorage over the past 16 months. As expected, there is a premium for ULS fuel. ULS production in Alaska is limited and requires additional resources to produce (Econ One Research, Inc., 2015).

distributed and sold in the Fairbanks area due to fuel blending. The strategy used here focuses on a low (HS No. 1) and a high (HS No. 2) fuel price differential estimate for Fairbanks. Situations where fuel type blending occurs would fall into a differential between the two estimated ULS Fairbanks differentials calculated here.

Table 1: Anchorage Rack Pricing Differential per Gallon HS No. 1[14]

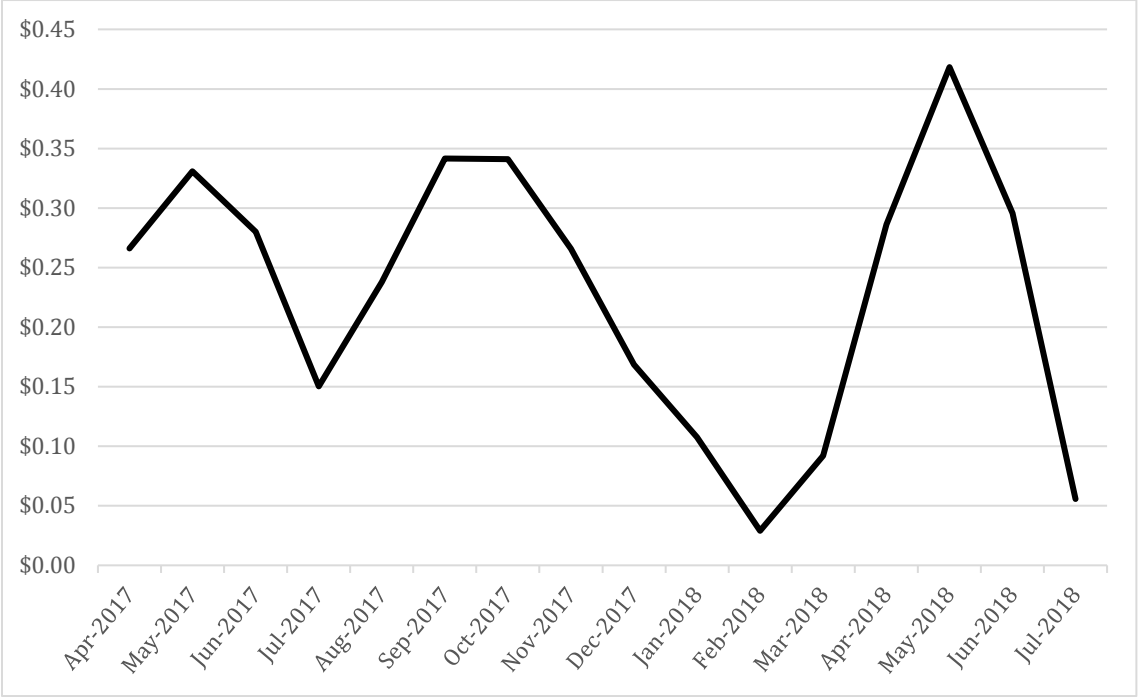
Month	ULS No. 1	HS No. 1	Price Spread ($)	Price Increase (%)
Apr-2017	2.20	1.93	0.27	13.99
May-2017	2.16	1.83	0.33	18.03
Jun-2017	2.06	1.78	0.28	15.73
Jul-2017	1.97	1.82	0.15	8.24
Aug-2017	2.15	1.91	0.24	12.57
Sep-2017	2.42	2.08	0.34	16.35
Oct-2017	2.45	2.11	0.34	16.11
Nov-2017	2.51	2.25	0.26	11.56
Dec-2017	2.39	2.22	0.17	7.66
Jan-2018	2.48	2.37	0.11	4.64
Feb-2018	2.43	2.40	0.03	1.25
Mar-2018	2.48	2.39	0.09	3.77
Apr-2018	2.66	2.37	0.29	12.24
May-2018	2.77	2.35	0.42	17.87
Jun-2018	2.78	2.48	0.30	12.10
Jul-2018	2.65	2.60	0.05	1.92
16 Month Average	**2.41**	**2.18**	**0.23**	**10.55**

Source: Alaska Department of Environmental Conservation, OPIS

Table 1 provides Anchorage price differentials by month for ULS No. 1 in comparison to HS No. 1. From April 2017 to July 2018, the 16-month average fuel price differential is 23 cents/gallon. This represents an average price differential of 10.55%. The average monthly ULS No. 1 price differential for during this time frame ranges from 3 – 42 cents/gallon.

[14] For presentation purposes all figures in each Differential Table have been rounded to two decimal points. This rounding will account for slight differences from of averages computed directly from raw OPIS data.

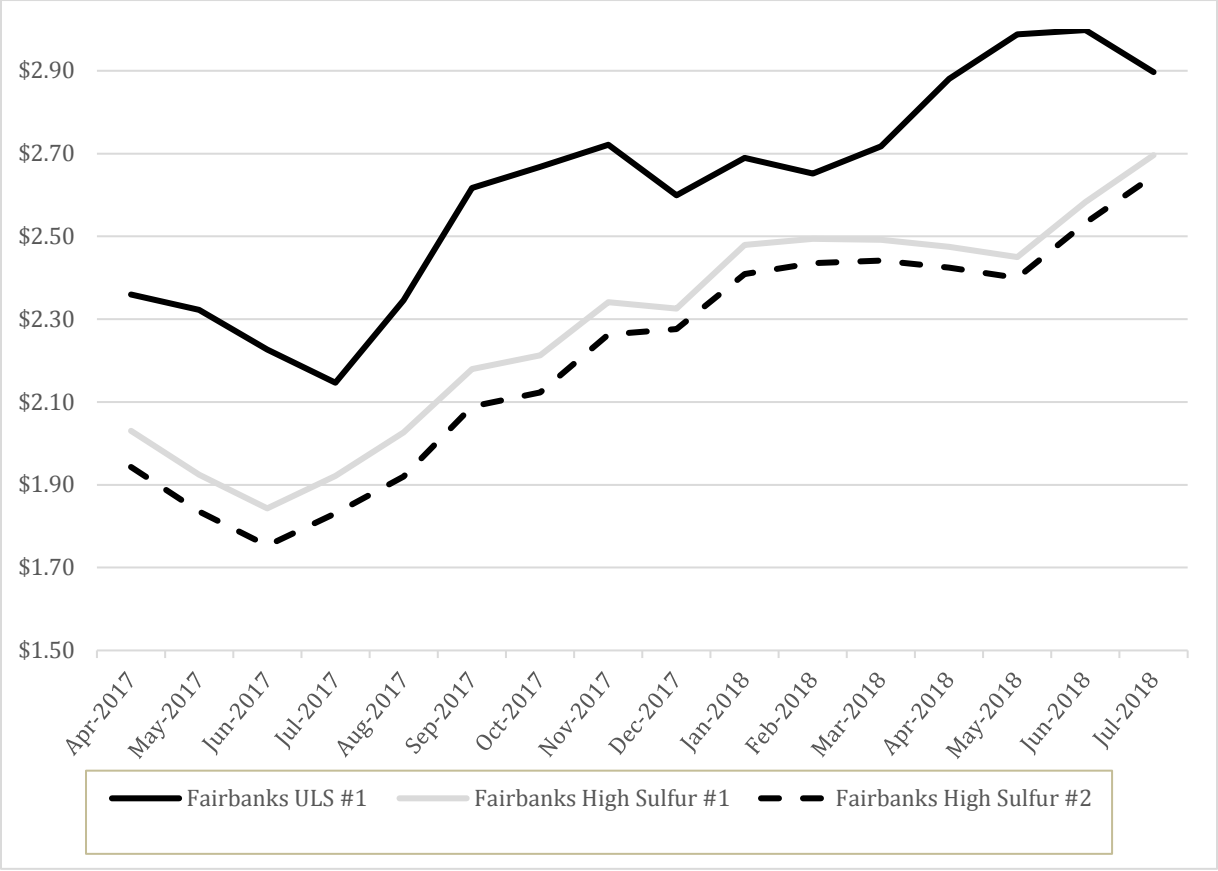
Figure 4: Anchorage Price Differential ULS No. 1 and HS No. 1, Dollars per Gallon



Source: Alaska Department of Environmental Conservation, OPIS

Figure 4 depicts the fuel price differential (detailed in *Table 1*) for the Anchorage wholesale market. Price differences range from a low of 3 cents/gallon to a high of 42 cents/gallon with a 16-month average differential of 23 cents/gallon. In 2018 the price spread increases significantly prior to dropping dramatically in July the most recent month of price data. The following set of figures and tables will explore the fuel price differential for the Fairbanks wholesale market.

Figure 5: Fairbanks Distillate Cost Comparison, Dollars per Gallon



Source: Alaska Department of Environmental Conservation, OPIS

Figure 5 presents wholesale rack fuel prices in Fairbanks over the past 16 months. As expected, there is a premium for ULS fuel. It is notable that the total price of ULS No. 1 has risen sharply since the summer of 2016. As the price difference between HS No. 1 and HS No. 2 is significant, this is taken into consideration through further analysis of each fuel type to develop specific scenarios for HS No. 1 and HS No. 2 fuel usage. The price differential between HS No. 1 and HS No. 2 is also analyzed separately.

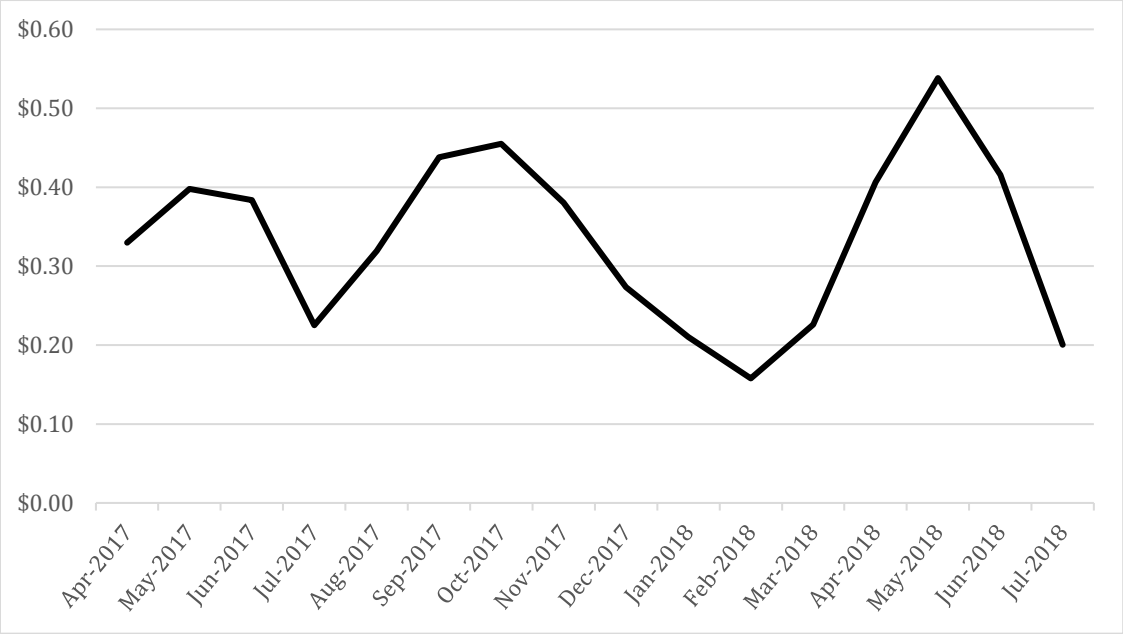
Table 2: Fairbanks Rack Pricing Differential per Gallon HS No. 1

Month	ULS No. 1	HS No. 1	Price Spread ($)	Price Increase (%)
Apr-2017	2.36	2.03	0.33	16.26
May-2017	2.32	1.93	0.39	20.21
Jun-2017	2.23	1.84	0.39	21.20
Jul-2017	2.15	1.92	0.23	11.98
Aug-2017	2.35	2.03	0.32	15.76
Sep-2017	2.62	2.18	0.44	20.18
Oct-2017	2.67	2.21	0.46	20.81
Nov-2017	2.72	2.34	0.38	16.24
Dec-2017	2.60	2.33	0.27	11.59
Jan-2018	2.69	2.48	0.21	8.47
Feb-2018	2.65	2.49	0.16	6.43
Mar-2018	2.72	2.49	0.23	9.24
Apr-2018	2.91	2.47	0.44	17.81
May-2018	2.99	2.45	0.54	22.04
Jun-2018	3.00	2.58	0.42	16.28
Jul-2018	2.90	2.70	0.20	7.41
16 Month Average	**2.62**	**2.28**	**0.34**	**15.12**

Source: Alaska Department of Environmental Conservation, OPIS

Table 2 presents Fairbanks price differentials month-by-month for ULS No. 1 in comparison to HS No. 1. From April 2017 to July 2018, the 16-month average fuel price differential is 34 cents/gallon, which represents an average premium of 15.12% for ULS No. 1 over HS No. 1. The average monthly ULS No. 1 price differential during this time frame ranges between 16 – 54 cents/gallon.

Figure 6: Fairbanks Price Differential ULS No. 1 and HS No. 1, Dollars per Gallon



Source: Alaska Department of Environmental Conservation, OPIS

Figure 6 presents the price differential of ULS No. 1 to HS No. 1 (detailed in *Table 2*) for the Fairbanks wholesale market. Price differences over the last 16-months range from a low of 16 cents/gallon to a high of 54 cents/gallon with an average difference of 34 cents/gallon.

Table 3: Fairbanks Rack Pricing Differential per Gallon HS No. 2

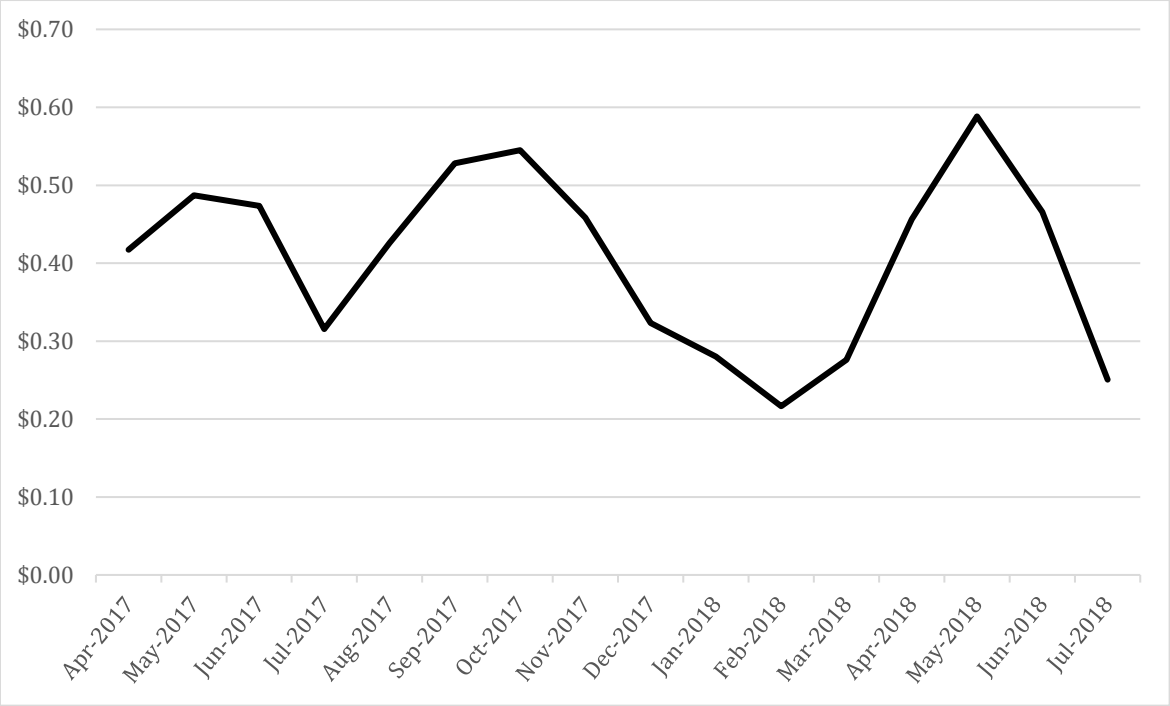
Month	ULS No.1	HS No. 2	Price Spread ($)	Price Increase (%)
Apr-2017	2.36	1.94	0.42	21.65
May-2017	2.32	1.84	0.48	26.09
Jun-2017	2.23	1.75	0.48	27.43
Jul-2017	2.15	1.83	0.32	17.49
Aug-2017	2.35	1.92	0.43	22.40
Sep-2017	2.62	2.09	0.53	25.36
Oct-2017	2.67	2.12	0.55	25.94
Nov-2017	2.72	2.26	0.46	20.35
Dec-2017	2.60	2.28	0.32	14.04
Jan-2018	2.69	2.41	0.28	11.62
Feb-2018	2.65	2.44	0.21	8.61
Mar-2018	2.72	2.44	0.28	11.48
Apr-2018	2.91	2.42	0.49	20.25
May-2018	2.99	2.40	0.59	24.58
Jun-2018	3.00	2.53	0.47	18.58
Jul-2018	2.90	2.65	0.25	9.43
16 Month Average	**2.62**	**2.21**	**0.41**	**18.55**

Source: Alaska Department of Environmental Conservation, OPIS

Table 3 provides Fairbanks price differentials by month for ULS No. 1 in comparison to HS No. 2. HS No. 2 is also used for residential heating oil in Fairbanks, and due to its lower price has the largest differentials.

The fuel price differentials, from April 2017 through July 2018 range from 21 to 59 cents/gallon. This results in a 16-month average price differential for ULS No. 1 in comparison to HS No. 2 in Fairbanks of 41 cents/gallon which represents an average premium of 18.55%.

Figure 7: Fairbanks Price Differential ULS No. 1 and HS No. 2, Dollars per Gallon



Source: Alaska Department of Environmental Conservation, OPIS

Figure 7 depicts ULS No. 1 over HS No. 2 fuel price differential (from *Table 3*) for the Fairbanks wholesale market. It is important to note that of all the fuel price differentials examined in this analysis, that ULS No. 1 over HS No. 2 for Fairbanks has the least amount of variance. While there still are month-to-month fluctuations the price premium has consistently been 22 cents/gallon or higher with 12 months being 30 cents/gallon or higher.

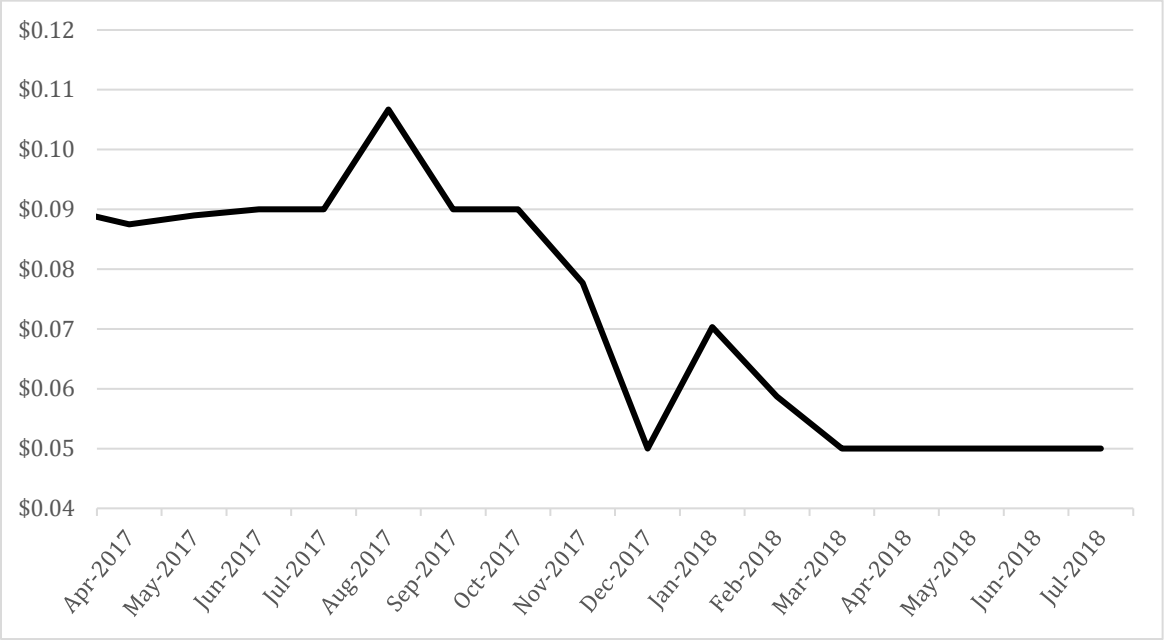
Table 4: Fairbanks Rack Pricing Differential per Gallon HS No. 1 and HS No. 2

Month	HS No. 1	HS No. 2	Price Spread ($)	Price Increase (%)
Apr-2017	2.03	1.94	0.09	4.64
May-2017	1.93	1.84	0.09	4.89
Jun-2017	1.84	1.75	0.09	5.14
Jul-2017	1.92	1.83	0.09	4.92
Aug-2017	2.03	1.92	0.11	5.73
Sep-2017	2.18	2.09	0.09	4.31
Oct-2017	2.21	2.12	0.09	4.25
Nov-2017	2.34	2.26	0.08	3.54
Dec-2017	2.33	2.28	0.05	2.19
Jan-2018	2.48	2.41	0.07	2.90
Feb-2018	2.49	2.44	0.05	2.05
Mar-2018	2.49	2.44	0.05	2.05
Apr-2018	2.47	2.42	0.05	2.07
May-2018	2.45	2.40	0.05	2.08
Jun-2018	2.58	2.53	0.05	1.98
Jul-2018	2.70	2.65	0.05	1.89
16-Month Average	**2.28**	**2.21**	**0.07**	**3.17**

Source: Alaska Department of Environmental Conservation, OPIS

Table 4 provides Fairbanks price differentials by month for HS No. 2 in comparison to HS No. 1. The fuel price differentials, from April 2017 through July 2018 range from 5 to 11 cents/gallon. This results in a 16-month average price differential for HS No. 2 in comparison to HS No. 1 in Fairbanks of 7 cents/gallon which represents an average premium of 3.17%.

Figure 8: Fairbanks Price Differential HS No. 2 and HS No. 1



Source: Alaska Department of Environmental Conservation, OPIS

Figure 8 depicts the fuel price differential (detailed in *Table 3*) for Fairbanks HS No. 2 and HS No. 1 wholesale market. Price differences range from a low of 5 cents/gallon to a high of 10 cents/gallon with a 16-month average differential of 7 cents/gallon. From August 2017 to March 2018 the price differential decreases significantly.

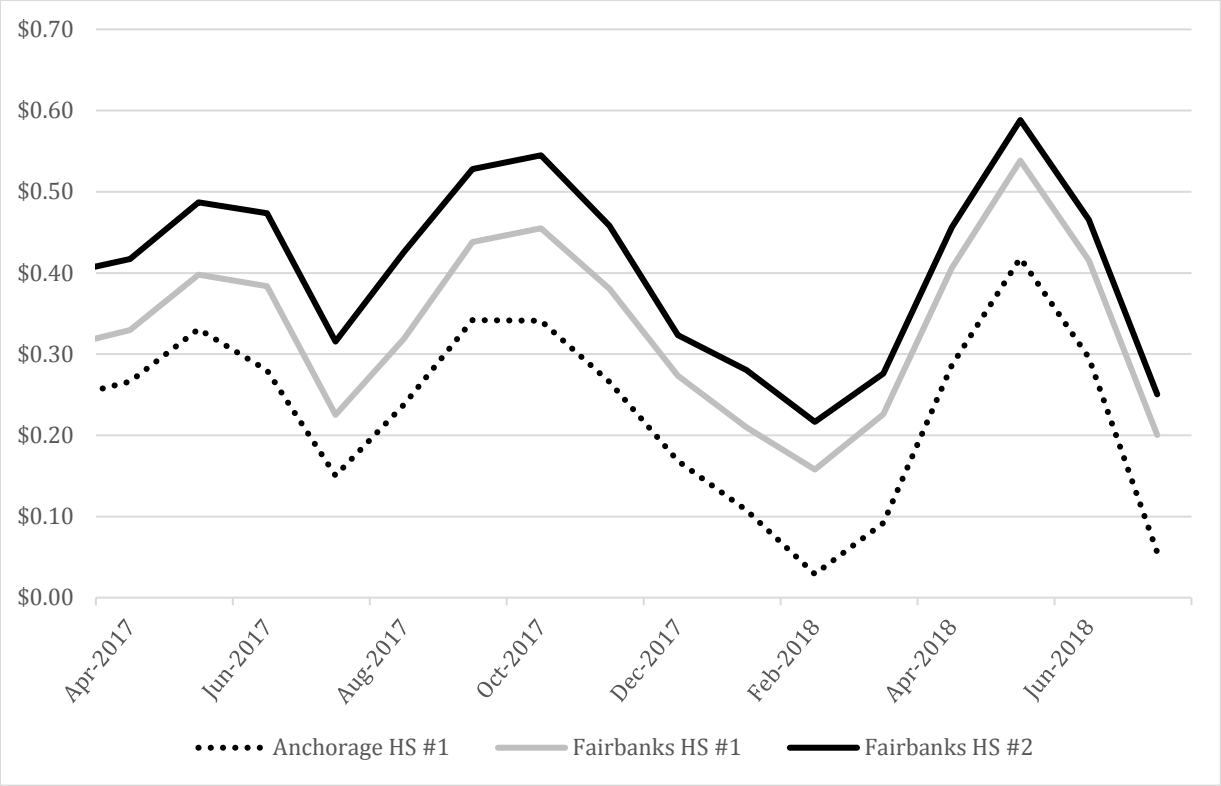
1.3 Fuel Differentials Summary

The incremental cost difference between HS and ULS, and between Fairbanks HS No. 1 and HS No. 2 heating fuel is important to review. A hypothetical change in fuel demand may induce further economic impacts and additional costs to households. The previous section reviewed the price differential of a potential shift from HS products to ULS No. 1, and Fairbanks HS No. 1 to HS No. 2 for individual rack fuels. In this section, a comprehensive examination of these differentials is provided.

These differentials indicate one of the cost impacts that hypothetical heating fuel requirements could have on Fairbanks. *Figure 8* includes ULS No. 1 fuel price differentials between Anchorage HS No. 1, Fairbanks HS No. 1 and Fairbanks HS No. 2.[15] *Figure 9* below includes the price differential between Fairbanks HS No. 1 and HS No. 2.

[15] Anacortes fuel prices were provided in the OPIS data, but are not evaluated, as there is no data to compute a ULS/HS differential (our current OPIS dataset indicates that Anacortes does not supply HS fuel). Northern Economics, found in previous work that reviewed 2006 and 2007 OPIS data from indicated that the Northwest area had a very small ULS price differential of about 1.5%. (Northern, 2007. p.57)

Figure 9: Alaska ULS No. 1 Price Differentials, Dollars per Gallon



Source: Alaska Department of Environmental Conservation, OPIS

The data in *Figure 9* indicates that the price differential between HS and ULS No. 1 ranges from 3 cents/gallon in Anchorage during February 2018, to 59 cents/gallon in Fairbanks during May 2018. The price differential between HS and ULS No. 1 fuel is significantly higher for Fairbanks than Anchorage. An explanation for this trend was provided by Northern Economics in their 2007 report: Cost Assessment for Diesel Fuel Transition in Western and Northern Alaska Communities, which states a key driver as, *"all ULS products are shipped by rail from Anchorage to Fairbanks, while the HS product is obtained from local refiners. The result is an average pricing premium…"*[16]

Additional fuel transportation logistics result in higher price premiums in the Fairbanks wholesale market. Anchorage fuel can be stored at Ship Creek where it then goes up the Alaska Railroad to Fairbanks. The latest publicly available information on the cost to ship fuel to Anchorage, from the Andeavor refinery in Kenai, is approximately 2 cents/gallon while the rail costs between Anchorage and Fairbanks is approximately 16 cents/gallon (Econ One Research, Inc., 2015, p.10). This study also estimated the cost of transport for ULS fuel from PSI's Valdez refinery to Fairbanks at approximately 20 cents/gallon (Econ One Research, Inc., 2015, p.25).

The fuel price differentials are reviewed here with the goal of developing an estimate of the direct expenditure impact to Fairbanks households. Information limitations result in an absence

[16] (Northern, 2007. p.56)

in evaluation of any potential added supplier capital costs to ship additional quantities of ULS and or HS No. 1 to Fairbanks. It is likely that, if these costs were to occur, they would be passed to the consumer. This analysis does not evaluate the effect of economies of scale with increased product demand or the potential for third party fuel distributors to enter the market to ship imported heating oil to Fairbanks and undercut competitors' prices. If these effects occurred, it is likely that this would result in no price increase or a potential for a price decrease for consumers. It is hard to predict which of these phenomena would occur and whether they would occur simultaneously. Though these factors are not analyzed in this review and beyond the scope of this study, ADEC recognizes that these factors are still important when analyzing the economic impacts of shifting to ULS heating fuel.

1.4 Fuel Cost Conclusions

Findings show through review of Fairbanks price data from April 2017 to July 2018, an average 34 cents/gallon for ULS over HS No. 1 and an average 41 cents/gallon premium for ULS over HS No. 2. Respectively, a shift from HS No. 1 to ULS No. 1 would result in a price increase of approximately 15%. While a shift from HS No. 2 to ULS No. 1 would result in a price increase of approximately 19%. A shift from HS No. 2 to HS No. 1 results in an average price differential of 7 cents/gallon, which represents an increase of approximately 3%. These price increases would directly affect household heating expenditures for fuel oil and are used in *Section II* to support the cost analysis.

Section II: Household Expenditure Scenarios Analysis

This section provides information on a cost model to explain potential changes in residential home heating expenditures assuming a switch to ultra-low sulfur (ULS) or shift from HS No. 2 to HS No. 1 heating fuel in the Fairbanks PM-2.5 Nonattainment Area. This section further employs a Monte Carlo analysis of the change in household heating oil expenditures from a switch to ULS, and a switch to HS No. 1. The objective of the Monte Carlo analysis is to help predict the expected change in household heating expenditures given a range of price differentials, annual household fuel consumption, and elasticity of demand estimates.

This assessment does not address the economic impact of both hypothetical heating fuel policy mandates, nor does it address the relative costs and benefits associated with conversion. Additional costs may include changes in fuel storage and distribution, whereas additional benefits would include improvements in air quality and reduced boiler maintenance. There is no assumed efficiency difference or boiler maintenance costs between HS No. 1 and HS No. 2. A switch to ULS or HS No. 1 may also produce behavioral responses by households which impact heating fuel demand in both the short and long run. It is important to note that the models do not take these issues into account and therefore results are only estimates based on the best information available at the time of publication.

2.1 Household Heating Oil Expenditure Changes from ULS

A potential transition from high sulfur (HS) home heating oil to ULS fuel would result in changes to household expenditures on fuel oil. Contributing factors include: fuel price differentials, heating efficiency changes, boiler maintenance cost reduction, and changes in the quantity of fuel used due to consumer price sensitivity. To assess how a potential transition from HS to ULS fuel might change household expenditures, this analysis makes several assumptions about key contributing factors likely to influence spending. First, expenditure estimates draw on the 16-month price differentials of 34 and 41.[17] Second, the differential adjusted prices are multiplied by the quantity of fuel consumed by a typical household using only a central oil-fired boiler. Finally, existing estimates of household fuel usage were adjusted to account for an average price sensitivity factor of -0.2%.

Evidence in the literature suggests that reducing sulfur and heat content in boiler fuel have a zero net change effect on fuel consumption.[18] Additional detail about the fundamental components of the estimates as well as supporting documentation is presented in the following discussion. It should also be noted that while the expenditure calculations do not include potential changes in maintenance costs that may occur, information about the potential savings have been included.

2.1.2 Household Heating Oil Expenditure Changes from HS No. 1

A potential switch from Fairbanks HS No. 2 to HS No. 1 would result in similar changes to household expenditures on fuel oil. It should be noted that the analysis of the change in household heating oil consumption from a switch to HS No. 1 uses the same underlying assumptions as discussed in *Section 2.2.1.* Differential prices between HS No. 1 and HS No. 2 are multiplied by the quantity of fuel consumed by a typical household using only a central oil-fired boiler. Existing estimates of household fuel usage were adjusted to account for an average price sensitivity factor of -0.2%. There is no assumed efficiency or boiler maintenance costs differences between HS No. 1 and HS No. 2.

2.1.3 Household Heating Oil Consumption

The cost scenarios are based on an assumed level of annual household heating oil demand. The estimated home heating oil usage is based on the Fairbanks Home Heating Telephone Survey conducted by Sierra Research Inc. Estimates utilized data[19] from 2011-2015, of the 2,304 households surveyed, 1,910 reported fuel quantities for at least one oil burning appliance. Homes that are heated only by a central oil burner are the most common heating configuration,

[17] 34 and 41 cents/gallon are the differentials presented in *Section I*. These differentials represent the change from ULS No. 1 to HS No. 1 and HS No. 1 to No. 2 respectively. All modeling in *Section 2* uses 33 and 40 cents/gallon as inputs. These values represent the non-rounded price differences and do not significantly alter results.
[18] See Section 2.1.5 Appliance Efficiency and Maintenance Cost with ULS.
[19] A description of the data set is included in *Appendix A*.

representing about 40% of homes in the data set. On average, central oil burner FNSB homes consumed 1,230 gallons of heating fuel oil per year as shown in *Table 5* below. Household expenditures on heating energy is on average $2,274 annually for homes in the data as shown in *Table 5*. Homes with a central oil burner and a wood stove are also common in the data set, representing about 20% of households. *Table 6* contains the oil and wood consumption quantities for homes with a central oil burner/wood stove appliance combination. This analysis does not account for cross price effects of oil on other energy sources, such as firewood. Respondents were asked to estimate their annual fuel consumption (in gallons and in cost) over the phone. Fuel consumption estimates are heavily influenced by home size, heating degree days[20], and regional climate factors. These dynamics contribute to variability in responses resulting in large standard deviations for the estimates.

Table 5: Summary of Typical Annual Central Oil Only Appliance Household Consumption

	Mean	**Median**	**Observations**
Oil Usage (gal)	1230 (719)	1100	787
Home Size (sq ft)	1895 (827)	1842	787
Household Expenditures	$2274 ($2352)	$1850	787

Source: Sierra Research Inc., Fairbanks Home Heating Telephone Survey, 2011-2015
Note: Standard Deviations in parentheses

[20] Heating degree days are a common metric used to compare space heating loads or demand across locations or by month/season within a specific area. Heating degree days represent the number of degrees that that day's average temperature is below a base or reference number, typically 65° F.

Table 6: Summary of Typical Annual Central Oil Wood Stove Appliance Household Consumption[21]

	Mean	Median	Observations
Oil Usage (gal)	906 (535)	800	403
Wood Usage (cord)	3.6 (2.3)	3	403
Home Size (sq ft)	1935 (709)	1855	403

Source: Sierra Research Inc., Fairbanks Home Heating Telephone Survey, 2011-2015
Note: Standard Deviations in parentheses

2.1.4 Gross Energy Content and Emissions from Heating Fuels

Table 7: Heating Source Energy Content[22]

Fuel Type	Content (BTU)	Unit
HS No. 1 and No. 2 Blend	135,000	/gal
Natural Gas	1,010,000	/mcf
Wood, Pellet	16,000,000	/ton
Wood, Cordwood Wtd. Avg.	20,372,980	/cord
Coal, Stoker	15,200,000	/ton
Ultra-Low Sulfur Heating Oil*	134,000	/gal

* Estimated from HS Blend energy content and EIA (https://www.eia.gov/todayinenergy/detail.php?id=20092)
Source: FNSB Community Research Quarterly-Based Heating Fuel Energy Content

Table 7 presents the energy content in BTU's by heating fuel source. These are the energy content assumptions used in this analysis. Wood energy content based is on a baseline moisture content of 20% and a weighted mixture of spruce, birch, and aspen cordwood. The fuel oil energy content used is a common HS No. 1 and HS No. 2 weighted mixture of 31.8% HS No. 1 and 68.2% HS No. 2 used in Fairbanks residential space heating

[21] We are unable to calculate estimates of the additional fuel cost expenditures to these homes at this time. Additional work is being conducted to understand cross-price elasticity for households in this category.
[22] EIA's calculation of the heat content of distillate fuel supply in the United States reflects these changes, going from about 138.6 thousand British thermal units (Btu) per gallon in 1994, to an estimated 137.5 thousand Btu per gallon in 2014.

Table 8: Comparison of Key Emission Factors and Sulfur Content for Fairbanks Heating Fuels

Fuel	Emission Factor (lb/mmBTU)		Sulfur Content (ppmv)
	$PM_{2.5}$	SO_2	
HS No. 1 & 2	0.00340	0.215	2,053
HS No. 1	0.00365	0.102	896
HS No. 2	0.00330	0.263	2,566
Natural Gas	0.00749	0.000591	<16
Coal	0.526	0.612	2,000
Wood Burning	0.18 – 2.0*	0.023	<500
ULS	~0.003-0.004	0.00171	15

ppmv = parts per million by volume
* Covering a range of uncertified and EPA-certified cordwood and pellet devices, assuming zero (oven dry) moisture content
Source: compiled by Sierra Research, Inc

Table 8 summarizes emission factors per unit of fuel energy (in lb/MMBTU) to enable equivalent comparisons across the range of solid, liquid and gaseous heating fuels used in Fairbanks. Emission factors are listed for both directly-emitted $PM_{2.5}$ and SO_2 (the most significant precursor in Fairbanks). Sulfur contents of each fuel (in parts per million) are also compared. As shown in Table 8, emission factors of $PM_{2.5}$ and SO_2 vary by several orders of magnitude across the range of common heating fuels. SO_2 emission factors are generally related to sulfur content. $PM_{2.5}$ emission factors are less dependent upon sulfur content, expect within the same class of fuel (e.g., heating oil).

2.1.5 Sulfur Content Reduction and Effects on Energy Content

A misconception surrounding the sulfur content of fuels is that a reduction in sulfur content decreases the energy content (BTU's) of the distillate fuel source. Sulfur being removed from distillate fuel during the refining process is known as catalytic hydrotreating; catalytic hydrotreating strips away sulfur as well as nitrogen, oxygen, and metals from hydrocarbon compounds. These reactions reduce the weight per gallon and a small portion of the thermal energy obtained from the combustion of a gallon of distillate fuel. The Energy Information Administration's (EIA) calculation of the heat content of distillate fuel supply in the United States reflects these changes in the weight per gallon, going from about 138.6 thousand BTU's per gallon to an estimated 137.5 thousand BTU per gallon. This represents less than a 1% loss in energy content per gallon during the refining process for the removal of sulfur

2.1.6 Price Elasticity of Demand

The price elasticity of demand measures how sensitive the quantity demanded of a good or service is to a change in price.[23] The sensitivity of the quantity of heating oil consumed by a household relative to changes in fuel price depends on several factors, including: temperature preferences, heating appliance(s) type, heating appliance(s) age, home age, and overall energy efficiency of the home. Demand is said to be "inelastic" when the percentage change in quantity is less than the percentage change in price. Demand is said to be "elastic" when the percentage change in quantity is greater than the percentage change in price. Cost scenarios are evaluated using an assumed oil price elasticity of 0.2%. Using an elasticity of 0 would imply that home heating oil demand is perfectly inelastic and that any change in the price of heating oil will not alter the quantity of heating oil demanded by households. This analysis assumes a constant price elasticity of demand[24] for all levels of home heating oil demand. The assumed rate of -0.2% is drawn from a study of home heating fuel demand conducted by Hirst, Goeltz, & Carney (1982) and implies that a 1% increase in the price of home heating oil will decrease the quantity demanded by 0.2%. Demand in this case is highly inelastic.[25]

Given a price increase to heating fuel, households will be incentivized to pursue activities that decrease heating expenditures. Immediate improvements such as caulking and weather stripping can reduce home heating expenditures in the average United States household by 2.5% (Gardner, 2008). A more drastic action, such as improving insulation and eliminating drafts within a home attic space, can reduce home heating expenditures by up to 7% (Gardner, 2008) in the typical US household. More simply put, homeowners will turn down their thermostat. FNSB households will have higher expenditures on home heating than the typical households similar relative to size due to extreme weather conditions. Cost savings associated with home efficiency improvements have a larger effect on FNSB household's price sensitivity to heating fuel. Specifically, FNSB homes have a more significant decrease in their price sensitivity to heating fuel due to cost savings from efficiency improvements.[26]

2.1.7 ULS and High Sulfur Cost Differentials

Drawing on *Section I*, the cost scenarios incorporate heating fuel price differentials based on 16 months (April 2017 through July 2018) of OPIS data for Fairbanks. No assumptions are made as to whether these price differentials will increase or decrease over time, and so all modeled scenarios employ constant price differentials. As mentioned in *Section 1.5*, the average price differential for ULS and HS No. 1 and ULS and HS No. 2, are 34 and 41 cents/gallon

[23] Examples of how the price elasticity of demand is calculated are explained in *Appendix B*.
[24] See *Appendix C*
[25] This estimate is for the short run effects of the transition to ULS fuel. Long run effects are not taken into consideration in this analysis, but would have lower costs compared to the short run.
[26] A decrease in the price sensitivity to heating fuel would indicate the households demand for will become more elastic.

respectively.[27] Both ULS price differentials are presented in different scenarios, referred to as Scenario 1 for the lower price differential of 34 cents/gallon, and Scenario 2 for the higher price differential of 41 cents/gallon. The ULS price differential of 34 cents/gallon represents the change between ULS and HS No. 1. The price differential of 41 cents/gallon represents the change between ULS and HS No. 2.

2.1.8 High Sulfur No. 1 and High Sulfur No. 2 Cost Differentials

In *Section 1.5* the Fairbanks HS price differential of 7 cents/gallon is based on the 16-month (April 2017-July 2018) averages of HS No. 1 and HS No. 2. Price differentials based on historical pricing data and calculations can be found in *Table 4*. This analysis does not make assumptions regarding current fuel usage mix consumed by the typical FNSB household.

2.1.9 Appliance Efficiency and Maintenance Cost with ULS

Heat content differences in HS fuel and ULS fuel mean that more ULS fuel will need to be burned to maintain the same indoor temperatures.[28] As noted *in Section II,* there is no assumed fuel efficiency or boiler maintenance cost difference between HS No. 1 and HS No. 2; therefore, this section will focus solely on the appliance efficiency and maintenance costs associated with a hypothetical switch to ULS. Approximately 1% more ULS fuel by volume would be required to compensate for the loss in heat content over HS fuel oil (EIA, 2018). However, boilers burning ULS fuels operate at a higher level of efficiency. It is assumed that the balance of these effects results in no change to fuel quantity consumption. This analysis accounts only for changes in fuel consumption, but a brief discussion of potential maintenance and repair costs is included. An explanation of assumptions in this analysis and a relevant synopsis of two Brookhaven National Laboratory Reports (Batey & McDonald, 2007 and Batey & McDonald, 2015) are included here.

A switch from HS fuel to ULS fuel has a significant effect on boiler efficiency. Batey and McDonald, 2015 compared the rates of 'boiler fouling' in systems using conventional heating oil and ULS fuel. Decreases in boiler efficiency are caused by buildup of soot on heat exchange surfaces. As shown in *Figure 10*, soot buildup is directly related to the sulfur content of the burned fuel.

[27] Due to rounding error, all modeled scenarios are calculated using values of 33 and 40 cents/gallon for ULS to HS No. 1 and ULS to HS No. 2 price differentials respectively.
[28] Refer to *Table 7* and *Table 8* for energy content and sulfur content be fuel type

Figure 10: Buildup of Soot and Particulates on Heat Exchange Plates for Identical Boilers using Different Fuels



Source: Batey and McDonald, 2015, p. 14

The amount of buildup also increases with time and causes the boiler to consume more fuel to compensate for lost energy during heat transfer. Batey and McDonald, 2007 conducted a cost-benefit analysis of a potential transition from conventional fuel oil (2,000-2,500 ppm) to low sulfur fuel (0.05% sulfur by weight) in New York State. This earlier report estimates that boilers burning conventional fuel oil experience a decrease in efficiency of 2% per year due to fouling. This analysis assumes a zero-net change in fuel quantity, which is conservative given the availability of information. Estimates of household heating expenditures can easily be adjusted to account for different efficiency levels. A procedure for adjustments is presented in *Section 2.2*.

The rate of boiler fouling may also impact household expenditures on maintenance calls and routine boiler cleaning. Batey and McDonald, 2015 used a Boiler Fouling Scale to compare the relative rate of buildup for residential fuel oil compared to ULS fuels. After approximately one year of operation, the conventional fuel oil group scored 2.15 and the ULS group scored 0.47. The ratio of boiler fouling is then 2.15/0.47 = 4.6. This means that boiler fouling occurs in conventional fuel oil boilers at a rate that is 4.6 times greater than ULS boilers. As boilers are typically cleaned every 1.5 to 2 years, a boiler using ULS fuel would only need to be cleaned approximately every 6.9 years. The Batey and McDonald, 2007 analysis assumed an average boiler cleaning service call would require 1.1 hours of labor. They also assumed service call costs ranging from $44 - $104 per hour. Based on the reduction in maintenance from the fuel switch, they estimated average annual household savings of $16 - $40. These savings are presented in 2007 dollars for New York State residents. Potential maintenance savings to FNSB residents are most likely larger than the Batey and McDonald, 2007 estimates due to a higher cost of living. These maintenance considerations are not included in the cost scenarios.

Batey and McDonald, 2015 found that a switch from conventional fuel oil to ULS could pose some risk to boiler systems with certain types of lip seals present in some oil burner pumps. 85% of existing residential oil burning systems use black nitrile seals, which were unaffected by the change in sulfur content. However, a smaller proportion of brown 'Viton' type seals are highly susceptible to degradation from ULS fuels. These seals were used for a brief period in the early 2000's but were observed to have a much higher rate of failure than their nitrile substitutes. This may indicate a further increase in boiler repair costs for some households. With the proportion of the vulnerable seals so low, this effect is not included in the cost scenarios.

2.2 Heating Oil Cost Models

A cost model was developed using Fairbanks Home Heating Telephone Survey data from 2011-2015 collected by Sierra Research for DEC to estimate the impact on household fuel expenditures in the FNSB area. Scenarios were developed using five key assumptions, and are listed below:

Scenario 1: Annual household heating oil use of 1,230 gallons, an own-price elasticity of demand of -0.2, no net change in efficiency and energy loss, 5% rate of discount, and a price differential of 34 cents/gallon for ULS.

Scenario 2: Annual household heating oil use of 1,230 gallons, an own-price elasticity of demand of -0.2, no net change in efficiency and energy loss, a 5% rate of discount, and a price differential of 41 cents/gallon for ULS.

Scenario 3: Annual household heating use of 1,230 gallons, an own-price elasticity of demand of -0.2, no net change in efficiency and energy loss, 5% rate of discount, and a price differential of 7 cents/gallon between HS No. 1 and HS No. 2.

Table 9: Summary of Heating Oil Cost Model Scenarios

Scenario	Gallons of Prior Fuel Usage	Price Differential Cents/Gallon	Own-Price Elasticity
1. HS No. 1 to ULS	1230	34	-0.2
2. HS No. 2 to ULS	1230	41	-0.2
3. HS No. 2 to HS No. 1	1230	7	-0.2

Source: Alaska Department of Environmental Conservation, UAF Cost Model

2.2.1 Monte Carlo Simulation

One objective of this study is to utilize a Monte Carlo analysis as a tool to help predict the expected change in household heating expenditure given a range of ULS differential, annual household fuel consumption, and elasticity of demand estimates. The Monte Carlo analysis can also be used to verify the estimates from *Section 2.2.* In a Monte Carlo simulation, a random value is computed for each of the variables based on a range of the estimates provided. This makes the Monte Carlo a valuable tool for predicting the probability of a given outcome with either limited data or many variables. The Monte Carlo Analysis uses the minimum, maximum, and mean value of those distributions to generate five-thousand random trials based on the range of estimates to predict the outcome of each. Based on the results from the generation of values, the expected change in household heating expenditure is computed. For this analysis, the inputs: ULS differentials, HS No. 1 differential, annual household fuel consumption, and elasticity of demand estimates were varied using triangular distribution.

Table 10: Summary of ULS Monte Carlo Inputs

Inputs			
Variable	**Min**	**Max**	**Mean**
ULS Differential	0.2	0.4	0.34
Gallons of Fuel	45	5000	1230
Own-Price Elasticity of Demand	0.2	0.7	0.4
Current Fuel Price			
$2.10			

Source*:* Alaska Department of Environmental Conservation, UAF Monte Carlo Model

Table 11: Summary of HS No. 1 Monte Carlo Inputs

Inputs			
Variable	**Min**	**Max**	**Mean**
ULS Differential	0.05	0.10	0.07
Gallons of Fuel	45	5000	1230
Own-Price Elasticity of Demand	0.2	0.7	0.4
Current Fuel Price			
$2.10			

Source*:* Alaska Department of Environmental Conservation, UAF Monte Carlo Model

Table 11 and Table 12 present a summary of the inputs used to conduct the ULS Monte Carlo Simulation, and the HS No. 1 Monte Carlo Simulation. Both models used a constant fuel price per gallon of $2.10 to calculate the expected change in household heating expenditure below.[29]

2.2.2 Results of Monte Carlo Simulation

Table 12: Results of ULS Household Heating Expenditure

Annual Change in Household Heating Expenditures			
Min	**Max**	**Mean**	**Median**
$10.64	$1,185.35	$329.73	$294.86

Source*:* Alaska Department of Environmental Conservation Monte Carlo Model

Based on the results of the ULS Monte Carlo, the average change in annual household expenditure is approximately $329.73. The minimum change in expenditure is $10.64, and the maximum is $1,185.35. The results of the Monte Carlo further verify the estimates presented in *Section 2.2,* as the mean estimate of changes in household heating expenditures fall within the expected range of $311.96 and $374.86, with the median change in household heating estimates falling slightly outside the expected range.

Table 13: Results of HS No. 1 Household Heating Expenditures

Annual Change in Household Heating Expenditures			
Min	**Max**	**Mean**	**Median**
$3.00	$303.61	$84.32	$76.12

Source*:* Alaska Department of Environmental Conservation Monte Carlo Model

Based on the results of the HS No. 1 Monte Carlo, the average change in annual household expenditure is approximately $84.32. The minimum change in expenditure is $3.00, and the

[29] Alaska Energy Data Gateway, 2006

maximum is $303.61. The results from the HS No. 1 Monte Carlo Simulation is slightly outside the estimates calculated in *Section 2.2* at an average increase of $84.32 from a switch to HS No. 1, the median estimate was slightly closer to *Section 2.2* estimates at a predicted household expenditure increase of $76.12.

Table 13 and 14 present the estimated change in expenditure based on the Monte Carlo inputs. The change in expenditure based on the Monte Carlo simulations is calculated for both ULS and HS No. 1 as so:

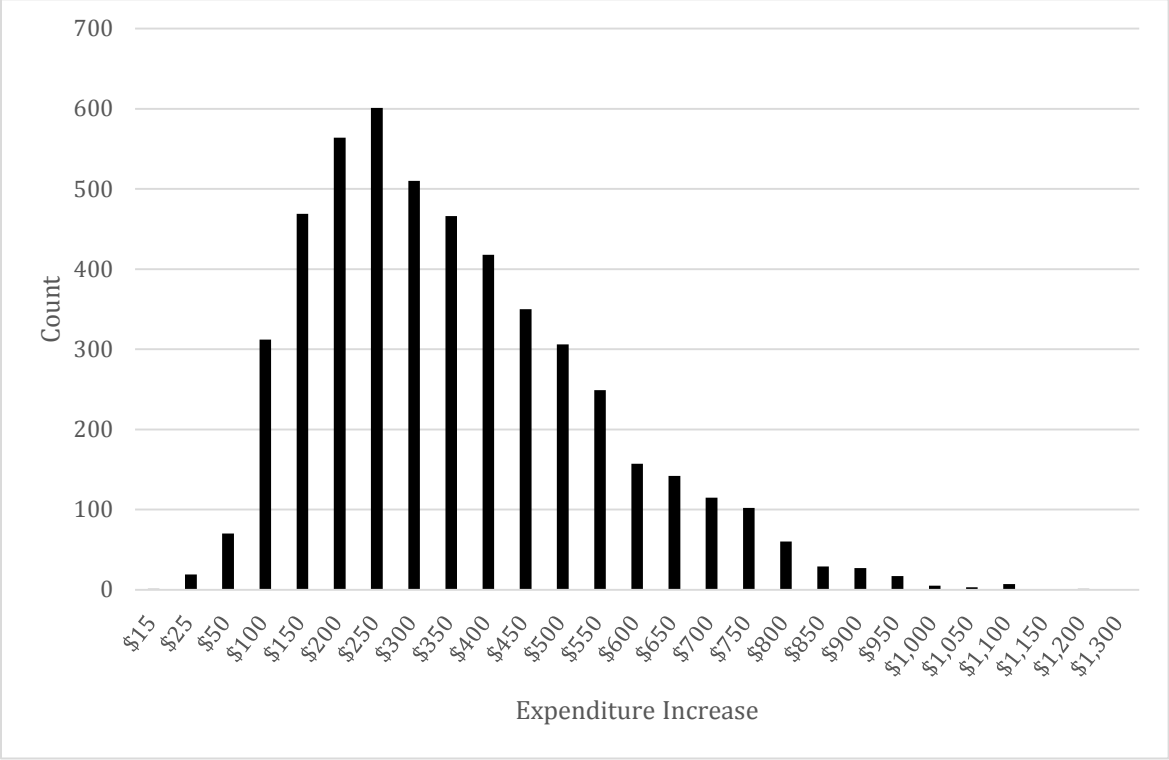
$$\left(\Delta Expenditure = \left(-Ed * \frac{Fuel}{Price}\right) * ULS\ Diff + Fuel\right) * (Price + ULS\ Diff) - (Fuel * Price)$$

Where *Fuel* is in gallons of heating oil per year used by the household, *Price* is the price of heating oil per gallon *ULS Diff* is the differential between HS No. 1 and ULS in the price per gallon. For example, using ULS Trial 1 calculations

$$\left(\Delta Expenditure = \left(-0.387 * \frac{603.19}{\$2.10}\right) * 0.28 + 603.19\right) * (\$2.10 + 0.28) - (603.19 * \$2.10) = \$96.16.$$

Using the above example, there is a predicted increase in annual household heating expenditure of $96.16.

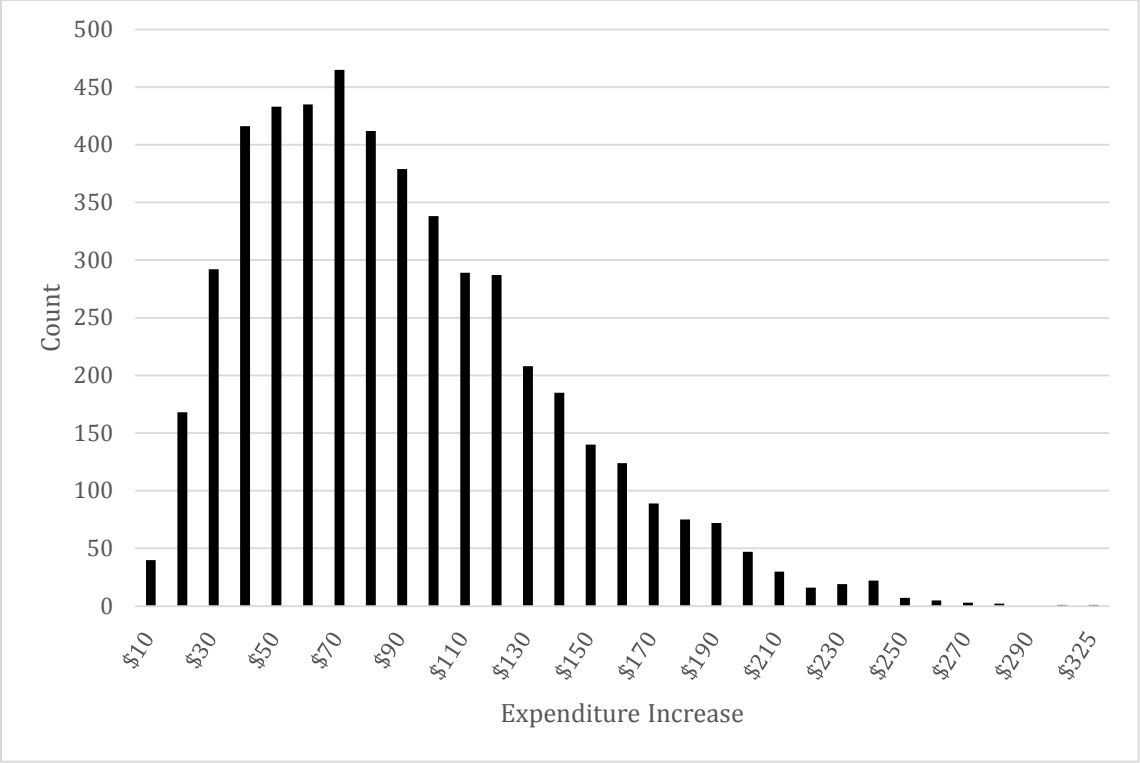
***Figure 11*: Distribution of Simulated Annual ULS Household Expenditure Increases**



Source: Alaska Department of Environmental Conservation Monte Carlo Model

Figure 11 presents the triangular distribution of simulated expenditure increases based on the ULS differential. Based on the ULS price differentials: 20, 34, and 41 cents/gallon, the average change in annual household expenditure is approximately $329.73. The minimum change in expenditure is $10.64, with a maximum change of $1,185.35. The distribution of the data is skewed right, approximately 90% of households are predicted to incur additional expenditures of $650 or less in the first year given a switch to ULS.

Figure 12: Distribution of Simulated Annual HS No. 1 Household Expenditure Increases



Source: Alaska Department of Environmental Conservation Monte Carlo Model

Figure 12 presents the triangular distribution of simulated expenditure increases based on the HS No. 1 differential. Applying the HS No. 1 price differentials: 5, 7, and 10 cents/gallon, the average change in annual household expenditure is approximately $84.32. The minimum change in expenditure is $3.00 and the maximum is $303.61. Again, the distribution of the data is skewed right, 90% of households are predicted to incur additional expenditures of $160 or less in the first year given a switch to HS No. 1.

2.3 Summary of Household Impact

These estimates vary depending on the assumed household sensitivity to price changes and the price differential used. These estimates do not include the change in maintenance costs associated with changing to ULS, the potential switch to alternate fuels (for example wood or natural gas), or behavioral responses which reflect a change in home heating practices. It should be noted that these estimates do not account for the potential switch to wood consumption, as this is a concern for the FNSB area connected to the sensitivity of consumers to fuel price increases and the substitutability of the type fuel used in the home.

2.3.1 Household Impact from Switch to ULS

The estimated cost of a potential ULS transition to an average FNSB household would be between $311.96 and $374.86 in the first year, with models accounting for consumer sensitivity to prices and the lower price differential of 34 cents/gallon resulting in the lower estimates. This represents a percent increase in household heating expenditures of 13.5% - 16.5% in the first year given average annual household heating expenditures of $2,274. The ULS estimate is further verified by the results of the Monte Carlo simulation. Results estimate a mean increase in household heating expenditures of $329.73 or 14.5% increase in household heating expenditures which land within the immediate estimates. The discounted NPV of the increased cost from implementation to 25 years varies between $4,396.76 and $5,283.22, with the higher estimate being associated with the 41 cents/gallon price differential assumption and relatively inelastic demand.

2.3.2 Household Impact from Switch to HS No. 1

The estimated cost of a potential HS No. 1 transition (from HS No. 2) to an average FNSB household is $68.31 in the first year given a price differential estimate of 7 cents/gallon. The results from the HS No. 1 Monte Carlo Simulation is slightly outside the estimates calculated in *Section 2.2* at a calculated average increase of $84.32 or 3.7% in annual household heating costs.

2.4 Potential Benefits of Switch to ULS

Thus far, this analysis has provided estimates of the additional heating costs incurred by households from a potential switch from HS to ULS. The potential benefits associated with a switch to ULS discussed in this section are strictly qualitative. Benefits of a switch to ULS include reduced PM-2.5 emissions, which could result in potential health benefits for FNSB residents. Improved air quality from a reduction in sulfur oxide, particulate matter, and nitrous oxide, could reduce asthma and cardiovascular induced hospitalizations from PM-2.5 episodes during winter months (State of Alaska Department of Epidemiology, 2010). Environmental benefits include reducing ground level smog, which would increase visibility for drivers and pedestrians. Other benefits from a hypothetical switch could include increased heating equipment efficiency, and lower maintenance costs from reduced boiler fouling as discussed in *Section 2.1.5*.

2.5 Limitations

The data used in this analysis lacked some socio-demographic, housing characteristics, and price data. Data such as household income, number of individuals living in the household, and other household spending preferences was not collected from the initial household level surveys. Housing characteristics such as number of bedrooms/bathrooms, garage space, and household energy efficiency were not included in the data set.

There are current data limitations regarding the prices Fairbanks households pay for their firewood. If this analysis tried to incorporate firewood prices at this time data limitations would result in a lack of price variability in the modeled scenarios. Many households in Fairbanks report collecting their own firewood instead purchasing. It would be of great value to gather data on the length of time spent collecting wood.

Conclusion

A prospective switch to ultra-low sulfur (ULS) heating oil is predicted to increase residential heating expenditures for the typical Fairbanks North Star Borough (FNSB) household. This does not take into consideration any potential benefits of the change, such as savings in boiler maintenance, decreased costs associated with improved air quality, and other factors. The cost analysis provided in *Section II* (using the price differentials from *Section I*) represents the likely range of estimates for an increase in residential heating expenditures given the available information and scope of the analysis is between $311.96 and $374.86 in the first year. This represents a predicted increase in household expenditures of 13.5%-16.5% in the first year given annual household heating expenditures of $2,274.

A prospective switch to HS No. 1 from HS No. 2 heating oil is predicted to slightly increase residential heating expenditures for the typical FNSB household. The cost analysis provided in *Section II* of a hypothetical switch to HS No. 1 represents a predicted increase in household heating expenditures of $68.31 in the first year. This represents a predicted increase in household expenditures of 3% in the first year.

This analysis does not account for cross-price effects on alternative energy sources like firewood, even though many FNSB homes contain more than one heating appliance. Future research should examine household expenditures and determine whether the reduction in particulates and improvement in air quality are acceptable given the cost to consumers in the FNSB.

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Sierra Research Inc. Fairbanks Home Heating Telephone Survey Data 2006-2015 - Unified Format, provided July 2, 2018

Appendix A

This analysis estimates the typical FNSB household fuel oil usage to be 1,230 gallons per year. This assumption is based on the Fairbanks Home Heating Telephone Survey Data 2006-2015, collected and prepared by Sierra Research Inc. Analysis data on fuel usage was limited to the continuous time period from 2011-2015. The survey collected information on household characteristics, appliance types, and fuel consumption for home heating. The survey focused on heating oil, firewood, natural gas, and coal as the primary heating fuels, and asked respondents to estimate their fuel consumption in terms of annual quantity and expenditures. ADEC's estimate of household oil consumption isolated households that burned only oil in a central boiler. For households with a central oil burner and reported oil consumption > 0, the average FNSB home uses 1,230 gallons of conventional heating oil per year. All calculations were performed using the statistical analysis software, STATA.

Appendix B

Price elasticity of demand measures the responsiveness of the quantity demanded of a good to a change in its price. It is calculated by the percentage change in quantity demanded divided by the percentage change in price. Price elasticity of demand figures are presented in absolute terms, as they typically consist of negative values, due to the inverse relationship between price and the quantity demanded of a good or service.

$$E_d = \frac{\%\Delta Q}{\%\Delta P} \qquad (3)$$

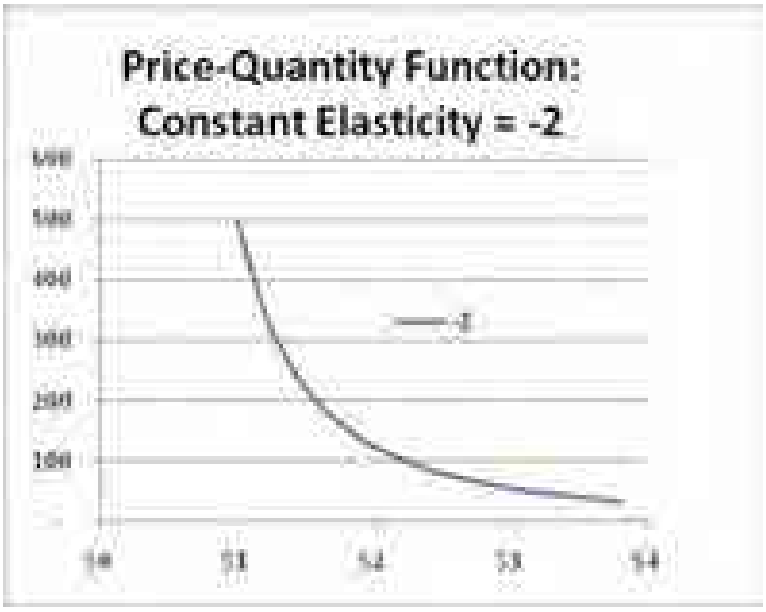
$$E_d = \frac{Q_2 - Q_1}{P_2 - P_1} \times \frac{P}{Q} \qquad (4)$$

These equations are all different ways to calculate the price elasticity of demand, with *equation 4* a more explicitly written version of *equation 3*. To find this value with calculus *equation 5* could be used. This uses the partial derivative of the quantity demanded with respect to the price of the good multiplied by the specific price of the good divided by the specific quantity demanded associated with that price.

$$E_d = \frac{\partial Q}{\partial P} \times \frac{P_0}{Q_0} \qquad (5)$$

Appendix C

Figure 13: Price-Quantity Function Elasticity Example



Source: Farris & Pfeifer 2010

Constant elasticity demand function means the elasticity of demand is the same at every point along the demand curve, but the slope is different at every point. This is represented in *equation 6* where ε is the price elasticity of demand and k is a constant.

$$Q = kP^{\varepsilon} \qquad (6)$$

Instead of a linear demand function, a constant elasticity demand function is assumed for this analysis because of the numerous assumptions made about heating fuel demand in the Fairbanks area. The post-transition level of heating oil demand is not known, so we assume fixed elasticity demand values across a range of fuel quantities.

Appendix D

Monte Carlo Analysis

The Monte Carlo Analysis, or Monte Carlo Simulation is a method of analysis developed in the 1940's which uses statistical sampling to obtain a probabilistic approximation to the solution of a model or an equation. Monte Carlo analysis uses the process of approximating the output of a model through the repetitive and random application of the model's framework. Through this process, the Monte Carlo simulation tells us based on a range of estimates how probable the

resulting outcomes are. A Monte Carlo analysis can include a mix of point estimates and distributions for the input parameters.

Fairbanks North Star Borough

Transit Fleet Natural Efforts

FINAL REPORT September 6, 2018

Compressed Natural Gas (CNG) Feasibility Study

Fairbanks North Star Borough

Project Location: 3175 Peger Road, Fairbanks, AK 99709

16-TRGPRJ-01 Transit Garage Expansion

wendel

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Executive Summary

Wendel was hired by the Fairbanks North Star Borough (FNSB) as a sub-consultant to Design Alaska to assist in the programming and the design necessary for the expansion of the Borough transit garage and assess the costs and feasibility of the incorporation of compressed natural gas (CNG) as an alternate fuel for transit vehicles.

FNSB currently operates fifteen (15) heavy duty diesel transit buses for the MACS nine (9) fixed routes and a total of ten (10) gasoline powered buses for the Grey Line and Van Tran paratransit demand response ADA service. The study includes a recommended bus replacement plan and various twenty (20) year projected cash flow analysis based on the first CNG buses arriving in 2020 and fleet wide implementation of CNG by 2027.

Even with the higher cost of natural gas in Fairbanks, the projected fuel cost savings utilizing CNG versus diesel or gasoline is $1,438,959. Subtracting the $1,422,454 added cost for CNG vehicles results in a 20 year net operating cost savings of $16,504 for both fleets combined.

The report includes a recommendation that the Borough proceed with a Phase 1 CNG contingent design using the guidance provided in this report. Total estimated Phase 1 costs are $123,768 and facilitate the future buildout of a fully CNG compliant maintenance and storage facility.

The total estimated overall facility capital costs for the CNG program is $2,840,392 with the Borough owned CNG fueling station being the largest estimated expense at $2,175,722. Although the fuel cost savings are not enough to also cover the added cost of CNG facility upgrades and CNG station costs, the Borough should consider the overall benefits of a future fleet wide implementation of CNG bus operations.

The CNG fueling station compressor and fueling system design recommended in the report meet the anticipated CNG usage required for conversion of the entire current fleet. The station can also handle an additional 10% expansion of the MACS and Van Tran transit fleets.

The net benefit of replacing both vehicle fleets with CNG vehicles produce significant reductions for each of the criteria pollutants (i.e., PM2.5, VOC, CO and NOx) as well as significant reductions in the carbon dioxide (CO_2) greenhouse gas emissions.

Fast Facts - During the 20 year period of the study:

- The amount of liquid fuels estimated to be displaced by CNG fuel is:
  - 2,109,555 diesel gallons for the 15 buses for the MACS fleet
  - 476,749 gasoline gallons for the 10 buses for the Van Tran fleet

- The estimated fuel cost savings of operating CNG buses is estimated to be:
  - $872,248 savings for the 15 buses for the MACS fleet
  - $566,711 for the 10 buses for the Van Tran fleet

- The initial increased cost of purchasing CNG buses is estimated to be:
  - $891,311 for the 25 buses for the MACS fleet
  - $531,143 for the 27 buses for the Van Tran fleet

Introduction

Fairbanks North Star Borough (FNSB) has commenced the programming and the design processes necessary for the expansion of the Borough Transit Garage. To aid in the planning process, this compressed natural gas (CNG) feasibility study will evaluate the potential cost, operational, and environmental impacts as a result of the incorporation of compressed natural gas (CNG) as an alternate fuel for transit vehicles. Included will be an overview of the financial impacts of constructing the new facility to accommodate the storage and maintenance of CNG vehicles and the costs of a privately owned CNG fueling facility on the property.

The initial evaluation was conducted May 1-3, 2018 in Fairbanks and included visits to the site at 3175 Peger Road. This process was conducted by the consulting team of Wendel, Design Alaska, and RIM Architects and included scheduled meetings with a number of Borough bus operations staff members and included a meeting with the natural gas provider Fairbanks Natural Gas, LLC.

The consulting team also met at the City of Fairbanks offices with Building Plans Examiner Stephen Anderson, Electrical Inspector Clemens Clooten, and Assistant Fire Marshal Kyle Green. Site plan ideas, and overall approach to facility requirements and potential CNG fueling station project and various code compliance issues were presented. This was an excellent meeting with very good discussion and engagement of City officials and fire marshal office.

The site assessment reviewed site layout, existing electric and natural gas utilities servicing the site, current site and building conditions. The operations assessment reviewed current fueling patterns, frequency of fueling occurrences, quantity of fuel required, and the amount of time required to perform fueling and service functions. Assessment includes both vehicles currently in the fleet, and those that may be added in the future as directed by FNSB.

The report identifies the necessary construction considerations for the new storage and maintenance facility to be in compliance with codes to allow for CNG vehicle storage including major repair work on CNG vehicles, engines, and onboard fuel storage systems.

The report confirms pressure and flow rate information for the proposed natural gas service, and provides an estimated annual usage of natural gas through a 10-year bus and paratransit replacement plan.

The report makes recommendations for a CNG fueling station as to the type of fueling system, site layout, location of dispensers, size of compressors and storage, etc. The report includes cost estimates for all recommended improvements

FNSB is exploring the utilization of Compressed Natural Gas (CNG) vehicles for city bus operations. This report examines a variety of issues involved in transitioning the heavy duty transit and paratransit vehicle fleets from diesel and gasoline to CNG. The study explores the capital and operational financial impacts of purchasing new replacement CNG buses. The primary vehicle financial impacts are with the added cost of the CNG engines, fuel systems, and storage tanks. Information on the safety of natural gas buses, changes in maintenance practices and suggested CNG training requirements are included in the report.

Some of the initial up front capital investments in CNG can be sizable, but in most cases can be considered a one-time expense. If you're building a costly fueling station such as that for CNG, this cost can be amortized or depreciated into the price of the fuel. This report provides the opinions of probable cost of a potential fueling station and projected fuel costs. Requirements and high level cost estimates for recommended measures to meet CNG code compliance for fleet storage, maintenance, and service areas are provided for the new operations and maintenance facility.

It is important to bear in mind when reading this report that the net present value of estimated annual cash flows and investment internal rates of return figures used are net differences in operating diesel and gasoline vehicles compared to CNG vehicles. Included are the extra incremental capital investments in new CNG vehicles, CNG facility requirements, and a new CNG fueling station on site. Natural gas costs for Alaska and Fairbanks are unique and much higher compared to the lower 48 states and this analysis highlights that reality. The environmental benefits are examined to quantify the emission reductions for separate pollutants (i.e., $PM_{2.5}$, VOC, CO, NOx, and CO_2) as a result of operating a CNG bus fleet versus the current diesel and gasoline buses.

Background

A number of issues need to be addressed when transitioning a fleet from traditional fuels to compressed natural gas. The following areas were addressed in the study:

A. CNG Vehicle Capital Costs
B. CNG Requirements For Maintenance, Fueling, and Bus Storage
C. Site, Fleet, and Fueling Analysis
D. CNG Fueling Station
E. Projected Diesel, Gasoline and Natural Gas Costs
F. CNG Diesel/Gasoline Gallon Equivalent (DGE/GGE) Cost
G. Safety, Training, and Maintenance Requirements for CNG Vehicles
H. Environmental Benefits of CNG Vehicles
I. Financial Analysis and Feasibility of the Overall CNG Project

A. Vehicle Capital Costs

1. CNG Vehicles

In the event a decision is made to transition fleets to CNG, it is recommended that the entire MACS and Van Tran fleets be replaced with CNG buses as soon as possible in order to achieve the maximum use of the CNG infrastructure investment. Wendel created a recommended 20 year fleet replacement schedule (Appendix A-1) for 1) the current MACS fixed route transit fleet replacements, and 2) the current Van Tran fleet replacements. The resulting schedule was used for the purposes of estimating fuel consumption and projecting the resulting financial impacts. Conversion of existing vehicles is not financially feasible and not recommended.

2. Borough Vehicle Equipment Fleet Fund (VEFF)

Wendel recommends setting up a formalized procurement cycle for buses and advises that the Borough at a minimum annually budget into the VEFF the typical 20% local match required to leverage state and federal grant programs. The fleet plan staggers replacements creating a more manageable system of bus replacements in the future. Once the fleets are replaced with CNG vehicles the recommended fleet replacement plan places MACS fixed route buses on a 15 year lifecycle and Van Tran paratransit cutaways on a 7

years lifecycle. The manufacturers recommended and Federal Transit Administration (FTA) required minimum service life policy is 12 year for heavy duty large bus and 5 years for light duty mid-sized buses. The FTA criteria has been in place since 1985. It is a generally accepted principal that extending vehicles significantly beyond the designed lifecycle leads to costlier repairs to systems on the vehicles that are generally not recouped during the remaining time the vehicle continues to be operated.

3. Fleet Replacements

The FNSB transit fixed route fleet is comprised of 15 fixed route buses. The fleet consists primarily of 30 and 35 foot diesel buses and also includes 2 – 2013 40 foot diesel buses expected to be transferred to FNSB from Anchorage, AK. The recommended fleet replacement schedule replaces all MACS buses by 2027 within the first 9 years of the feasibility plan scenario. The Borough is already planning 4 replacements of 2007 Gilligs in 2020 and 3 additional are recommended each year in 2021 and 2022. This completes the replacement of the 10 older 2007 Gilligs. The remaining 3 – 2014 Gilligs are replaced in 2026 and the final 2 – 2013 40 foot Gilligs from Anchorage are replaced in 2027 to complete the conversion to CNG for MACS.

The Van Tran fleet has a total of ten (10) E-350 and E-450 Ford cutaway (a bus body purpose built on an existing chassis produced by manufactures such as Ford, Chevrolet, International, etc.) gasoline powered buses for the Grey Line and Van Tran paratransit demand response ADA service. The Borough already has 3 buses scheduled for replacement in 2019. Because the natural gas fueling infrastructure would not likely be in place until 2020 it is recommended those 3 units be replaced with gasoline vehicles. The Borough could then begin purchasing CNG cutaway vehicles with 2 each in 2020 and 2021, 1 each in 2022, 2024 and 2025, and the remaining 3 in 2026 to complete the conversion to CNG for the entire Van Tran fleet.

Table I. on page 3.3 lists the years and number of replacements for each fleet. The green highlight indicates when full CNG fleet implementation has been reached.

Table I. - CNG Fleet Replacements MACS & Van Tran

Fiscal Year	MACS Fleet	Van Tran Fleet
2019	0	3 – Gasoline
2020	4	2
2021	3	2
2022	3	1
2023	0	0
2024	0	1
2025	0	1
2026*	3	**3**
2027*	**2**	2
2028	0	2
2029	0	1
2030	0	0
2031	0	1
2032	4	1
2033	3	3
2034	3	2
2035	0	2
2036	0	1
2037	0	0
2038	3	1
*** Entire Fleet Operating on CNG**		

In the current market there are only two available CNG engine for heavy duty large transit buses. Those are the Cummins-Westport ISL-G and ISL-G-NZ (Near Zero) engines. The ISL-G is the standard CNG engine and the NZ model is an optional low NOx (oxides of nitrogen) natural gas engine with exhaust emissions that are 90% lower than the current EPA NOx limit of 0.2 g/bhp-hr (grams per brake horsepower-hour). The ISL G is a spark ignited, factory-built dedicated natural gas engine, manufactured by Cummins on the same assembly line as the ISL-9 diesel used in many of FNSB's current MACS transit buses. Cummins-Westport was formed in 2001 as a 50:50 joint venture between Cummins Inc. and Westport Innovations.

The price differential for a new Gillig CNG bus with a 155 diesel gallon equivalent (DGE) CNG tank system and a Cummins ISL-G natural gas engine is estimated to be $48,397. This configuration is dedicated CNG operation. Cost figures were verified through a comparison of Washington State bid sources where a 35 foot Gillig bus base bid is priced at: $419,616 for diesel and $477,040 for CNG with the ISL-G-NZ (Near Zero). A New Flyer bus is priced at $439,070 for diesel and $468,013 for ISL-G CNG. The differential utilized for the financial analysis compares the lower cost Gillig diesel with the lower cost New Flyer CNG. This price differential could be $6,000 lower in the event the Gillig CNG Bus is chosen without the more expensive ISL-G-NZ low NOx natural gas engine which carries a $15,000 premium on the Gillig CNG pricing for the Washington state bid.

The price differential for a new Ford E350 and E450 StarTrans cutaway with a dedicated CNG package versus a gasoline engine is $22,000. Pricing was provided by Ford authorized CNG installer A-1 Alternative Fuel Systems in Elkhart, Indiana. A-1 is a Ford Qualified Vehicle Modifier (QVM). It is important to work with only QVM suppliers to ensure that the Ford OEM warranty will remain intact on any vehicle modified.

The E-350 6.2L w/ Gaseous Fuel Prep Engine Package - 20 GGE $20,500 - $21,000; 30 GGE $21,500-$22,000. The E-450 6.8L w/ Gaseous Fuel Prep Engine Package - 30 GGE $17,500-18,000; 40 GGE $19,500 - $20,500. Because the E350 6.2L is the most common in the fleet the higher threshold cost of $22,000 was used for the study. CNG storage tanks are generally installed under the bus body on the chassis, but other roof and rear compartment options are also becoming available. Cutaway CNG buses would be ordered as a dedicated CNG configuration and not a bi-fuel application. In bi-fuel applications the vehicle can start on gasoline and then switch to CNG operation.

The financial scenario period of the study extends to 2039. The recommended fleet replacement plan illustrates the actual lifecycle after replacement to CNG with all future CNG replacements assuming a bus lifecycle of 15 years for large bus and 7 years for cutaways. After the fleet is 100% converted to CNG, additional vehicle upcharges are also proportionally cost allocated through 2039 for assumed future replacements of the CNG buses listed in Table I. CNG Fleet Replacements MACS & Van Tran on page 3.3.

B. CNG Requirements for Maintenance, Fueling and Bus Storage



Looking down the center isle of a typical transit maintenance garage with opposite facing maintenance bays.

Evaluating the impacts to buildings where CNG vehicles may be maintained and stored is an important element of the study. CNG is natural gas (methane CH_4) compressed for on board vehicle storage and used as a fuel source. Methane is lighter than air, naturally rises, and is part of nearly everyone's daily life as the natural gas we use to cook and heat our homes. In its naturally occurring state, it is odorless, colorless, tasteless and nontoxic. Methane is highly reactive with oxygen, making it a valuable fuel but also an explosive danger if not properly detected and controlled. At certain levels natural gas is highly explosive so methane sensors are used to detect and automatically ventilate spaces well before natural gas reaches dangerous levels.

This section of the report provides our code review analysis, design options and high level opinion of cost for the building construction and systems required and recommended for CNG vehicles. At the time of this report it should be noted that in preparing this analysis, the local jurisdiction has adopted International Mechanical Code (IMC) 2015 for ventilation. Chapter 4 Table 403.3.1.1 of the IMC contains the current requirements. In the event a newer codes is adopted the CNG requirements for maintenance, indoor fueling and bus storage should be re-examined for possible changes.

1. Maintenance Repair Areas

The appropriate codes look at maintenance repair bays in two different categories; major repair and minor repair. Major repair consists of repair on the fuel systems as well as body work, welding, grinding, etc. Minor repairs include activities such as brake changes, tire

changes, oil and lube services. For the cost estimate, two scenarios are presented, 1) determining the cost of making the entire maintenance area compliant for major maintenance, 2) partition off two repair bays and pricing the partition and mechanical system. When ultimately determining the pros and cons of the chosen approach FNSB can also understand the financial impacts.

The major repair area has minimum ventilation requirements in cubic feet per minute (CFM) to ensure that any released gas can be safely evacuated from the building. Ventilation is required at a rate of 1 cfm/12 cubic feet (CF) of room volume, which is equivalent to five air changes per hour. This can be handled by continuous ventilation, or by having a gas detection system interlocked with emergency exhaust fans that can provide this ventilation rate. With Fairbank's outside air temperatures and quality, the continuous ventilation approach is not desirable. The minor repair areas do not have any code specific requirements beyond the minimum ventilation rate required for a diesel maintenance garage. The minimum ventilation rate currently required by code is 0.75 cfm/sf.

It is common practice to provide a gas detection system throughout a repair garage that monitors for carbon monoxide (CO) and nitrogen dioxide (NO_2). Having this system in place as a base design would allow detectors to be added to monitor for methane as well. With a nominal expansion to the base gas detection system it would be fairly simple to meet the intent of the code for CNG. This system would be interlocked with emergency exhaust fans that upon detection would energize and purge the space. In this case, only the minimum ventilation rate of 0.75 cfm/sf would be required continuously, and not five air changes.

Because continuous ventilation would not be provided, and because methane is lighter than air naturally rising to the highest point of the facility, the top 18 inches of the space near the ceiling would have to be classified as Class 1, Division 2 (explosion proof) as defined by the National Electric Code (NEC). To mitigate additional electrical work if CNG is adopted in the future all electrical raceways or wiring should be designed and constructed outside of this classified zone. Any wiring that is installed or would be passing through this zone would have to comply with requirements for installation within Class 1, Division 2 zone. The lighting fixtures provided in the repair bays have to be vented or designed (typically lensed)

in such a way as to prevent collecting any gas inside the fixture.

In major repair areas, heat producing equipment shall not consist of open flame heaters or any equipment with exposed surface temperatures in excess of 750°F.

The previous design and construction considerations can easily be applied to the entire repair garage area, allowing the greatest user flexibility. Any bus can be pulled into any bay to do any type of work.

Often times in an effort to reduce overall construction cost, especially in existing buildings, major maintenance of CNG vehicles can be restricted to a limited number of maintenance repair bays. By providing a rated separation from the rest of the facility, only a dedicated area of major maintenance would have to be up-fitted with methane detection and emergency exhaust fans. For repair bays to be isolated, interior walls must separate the maintenance bay from the rest of the building and are to be continuous from floor to ceiling, securely anchored, and maintain a 2 hour fire rating. Each maintenance repair bay would also require a vapor-sealing, self-closing 2 hour rated overhead door. In our analysis with new construction it is actually less costly to have the entire maintenance area CNG compliant as compared to constructing two CNG complaint work repair bays.

Finally, a typical diesel vehicle repair garage will be equipped with hose reels for tailpipe exhaust systems. This system is necessary to safely remove the exhaust of any vehicle that needs to be running indoors to perform maintenance or testing. A standard diesel bus requires a system that can handle temperatures of 700°F with an exhaust airflow of 700 CFM. CNG buses have discharge temperatures near 1170°F and airflow rates of approximately 1180 CFM. Our cost estimate captures the difference in cost between these two options to better understand the upgrade cost to CNG. Whether the garage is designed for immediate use of CNG vehicles or designed with the thought that CNG vehicles may procured in the future, it would be beneficial to install the system with the fans and hoses that can handle the higher temperatures and flow rates.

2. Indoor Fueling and Service Lane Area

Fueling CNG buses indoors provides shelter from the weather, as well as a controlled work environment. It is important to understand the National Fire Protection Association (NFPA), CNG code restrictions and implications that come with indoor fueling. Per earlier versions of the NFPA 52 (Vehicular Natural Gas Fuel Systems Code), when there is a room within a building where CNG is dispensed, the International Fire Code (IFC) required deflagration venting to be provided in exterior walls and/or roofs. Deflagration venting is a means of controlling damage by releasing explosive forces through a wall or ceiling panel opening engineered for that purpose. At least one wall must be an exterior wall and any interior walls separating the fueling room from the rest of the building are to be continuous from floor to ceiling, securely anchored, and maintain a 2 hour fire rating. By providing the deflagration panels and securing the interior walls, if there was ever a pressure releasing event, the area is designed to release outward and away from the rest of the building. Access to the room from within the building is permitted where it is through a barrier space having two vapor-sealing, self-closing fire doors. Essentially this is a vestibule type design. This requirement has changed however within the NFPA 52 - 2016 update and does not require deflagration panels. This will need further discussion with the stakeholder group.

For indoor, fast-fueling, with outdoor storage and compression, attended fueling requires a gas detection system equipped to sound a latched alarm and visually indicated when a maximum of one-fifth of the lower flammability limit is reached. Actuation of the gas detection system shall shut down the compressor and stop the flow of gas into the structure. Reactivation of the fueling system must be by a manual reset. Again, CO and NO_2 detection would be provided as a base design so methane detection would need to be provided in the fueling area and tied into the gas detection system as a separate zone. This will be interlocked with emergency exhaust fans located in this space. The emergency exhaust fans would be required to be mounted on the highest point of the roof and exhaust the air from within the top 18 inches of the service lane area of the building. Fans would be sized to exhaust at a rate of five air changes per hour. Make-up air would have to be provided and supplied low in the space to facilitate uniform air movement across the room. Providing the air low, would help reduce the potential of freezing pipes, but care must be taken in the design so if the system were to activate, additional damage was not caused by freezing and

bursting water piping.

CNG fueling inside of the building requires classification of the entire space designated as fueling to be classified as Class 1, Division 2 per the NFPA 70. The National Electrical Code (NEC), or NFPA 70, is a regionally adoptable standard for the safe installation of electrical wiring and equipment in the United States. It is part of the National Fire Codes series published by the NFPA. All electrical equipment such as panelboards, lighting and similar devices that are provided within the space have to be listed for use in such areas. All of the associated wiring methods also have to comply with requirements as described in the NEC for installation within Class 1, Division 2 areas.

In fuel dispensing areas, heat producing equipment shall not consist of open flame heaters or any equipment with exposed surface temperatures in excess of 750°F. All forced air heating, air-conditioning and ventilating systems serving this area are required to be dedicated systems and not serve any other part of the building. The fuel dispensing area shall be located at street level with no dispenser located more than 50ft from the vehicle exit to, or entrance from, the outside of the building.

3. Bus Storage Area

Although the buses being stored indoors are fueled by CNG, there is very little impact of CNG on the space requirements for this area. Since the buses are essentially sitting idle and not being worked on, there is very little potential for a leak and/or release. The code addresses this typically as an area that does not require any additional systems for CNG. In the base facility design this space would require only the minimum amount of ventilation as required by code which is 0.75 cfm/sf. This minimum ventilation requirement satisfies the presence of CNG. It should be noted that the code does allow an exception to provide a reduced airflow as low as 0.05 cfm/sf if a gas detection system is installed and interlocked with emergency exhaust fans. The gas detection system would need to monitor CO and NO_2. This would be a decision of the design engineer providing the base system, but would be beneficial to save on energy costs and reduce the amount of outside air being brought into the space.

Even though no additional equipment is required by code for CNG vehicles in this space, some owners want the peace of mind to know that they are adequately informed if there is a leak. Methane detectors could be added onto the base systems gas detection equipment and provide alarms if certain levels of methane were reached. This would be above and beyond the code, but might be seen as value added with a small premium in overall price.

CNG Ready Facility Premiums *

Option A: $374,550 - Entire Repair Facility CNG Complaint

Option B: $396,125 - Two Separated CNG Compliant Repair Bays

Indoor CNG Fueling: $97,996

Bus Storage: $99,109 – *Optional* Methane Detection Add-On

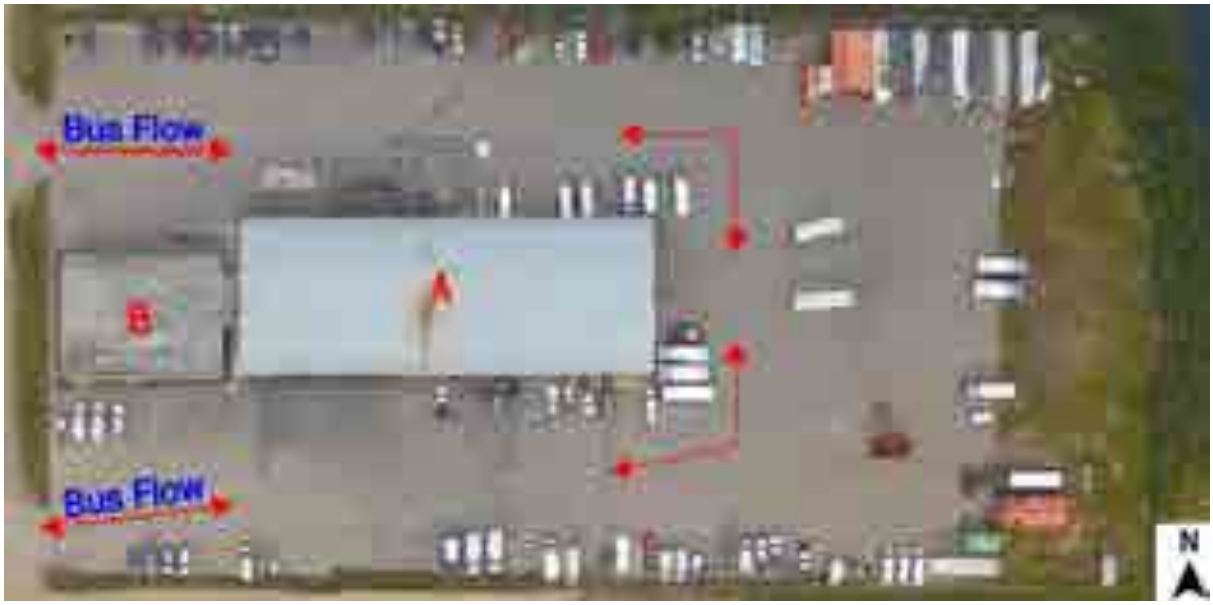
* Cost for equipment, escalation costs for Alaska construction, contingency, general conditions, or the general contractor fees as outlined in the attached Appendix Exhibit A-4.

C. Site, Fleet and Fueling Analysis

1. Current Site Layout

The FNSB transit operation is located at 3175 Peger Road and is comprised of Administration, Operations and Maintenance Offices and Parking, Bus Maintenance Repair, Bus Parts, and Indoor Bus Storage, Internal Fueling and Service Lane (A). The balance of the site is parking, storage, green space or unimproved areas. The Borough Emergency Operations building is to the west of and connected to the Transit Garage facility (B).

3175 Peger Road - Aerial Map View



The current bus flow on the property is not defined by signage but typically movements are in and of the lot from the main Northwest entrance (top left of photo). The opposite Southwest entrance/exit also can accommodate fixed route or paratransit bus traffic.

2. Current Utilities

a. Electrical Service

The site is currently serviced by Golden Valley Electrical Association. There are distribution lines and ample three phase overhead lines near the site to serve a new CNG station. The exact voltage needs to be field verified in design by the electric utility. The large size of the electric motors required on a CNG station will require a separate electric service and meter. It is anticipated that there would be a $9,381 approximate cost for providing the new meter and services. Once a location is chosen, typically a minimum of two weeks is required for planning and four-six additional weeks for engineering before improvements could be ordered for construction. It is anticipated that this would have no significant construction timeline on a potential CNG station.

b. Natural Gas Service

The site is currently serviced by Fairbanks Natural Gas (FNG) LLC. Wendel met with President and CEO Daniel Britton at the FNG offices on May 3rd. There is currently a very good natural gas service line to the site and current building. The current system volume and 60 psi pressure are more than adequate for the demand that will be required for a CNG station that would adequately serve both the MACS and Van Tran vehicles. The available volume could significantly increase the number CNG vehicles fueled per hour.

The CNG station will require a dedicated higher pressure gas line gas meter. FNG charges $50.00 for the first 100' including meter and $7 for each additional foot. The distance is approximately 800 feet for an estimated cost of $5,000.

3. Frequency of Fueling Occurrences

FNSB provided daily, monthly and yearly fueling data for both MACS and Van Tran vehicles. Although some minor fueling could occur throughout the day, the majority of fueling and servicing operations are handled by one or two service staff beginning at 6:00 pm and ending between 2:30 – 3:00 AM Monday – Friday. There is limited fueling on Saturday. The frequency of fueling remains fairly constant at two (2) vehicles per hour in one service lane. The time requirement is currently about 20-30 minutes per vehicle. Interviews with staff highlighted that additional cleaning operations and vehicle checklist service items are performed in the service lane requiring extra time.

4. Quantity of Fuel Required

Sample diesel refueling data was analyzed to provide an accurate representation of current maximum fueling requirements. Tables II. MACS Diesel Fuel Consumption summarize the gross daily fuel gallons based on this sample fueling data for the current fleet. Currently Van Tran vehicles fuel at a local gas station so no timed refueling data was available.

Table II. – MACS Diesel Fuel Consumption

Unit Num	Annual Gallons	Monthly Average	Daily Average
141	9,893	824	39
142	9,617	801	38
143	9,928	827	40
71	11,071	923	44
710	7,598	633	30
72	8,014	668	41
73	7,566	630	42
74	6,481	540	42
75	7,139	595	33
76	8,187	682	33
77	7,213	601	30
78	5,466	456	30
79	7,717	643	31
T945	80	7	13
T946	1,305	109	21
Averages	8,145	679	36
Totals	107,275	8,939	540

***** Excludes Units T945-T946

The critical measure for design of the CNG compressors and dispensers is the maximum required natural gas volume per hour necessary to meet the number of equivalents gallons of gasoline or diesel fuel needed each hour of fueling. One DGE is equivalent to 143.94 cubic feet and one GGE 126.67 cubic feet of natural gas.

The Monday – Friday maximum daily (540 diesel gallons) requirement for natural gas is 77,728 cubic feet per day or approximately 388,638 cubic feet of natural gas per week for the large bus fleet. The current hourly fueling throughput requirements for the current fleet is only two buses per hour or the equivalent of 60-85 diesel gallons. This translates to a requirement for maximum natural gas volume of only 12,235 cubic feet per hour. Adding Van Tran fueling increases this but would have minimal hourly impact to evening fueling.

The CNG station compression is sized for the evening timeframes Monday-Friday when maximum throughput of fueling operations are realized. However the current gas service

could provide the capability to pull a much larger volume of cubic feet of gas per hour with larger compressors.

The baseline projected DGE average per year for each fixed route bus is 8,145 gallons. The baseline projected GGE per year for each paratransit buses is 2,821 gallons. The Van Tran fueling averages are based on fiscal year 2016 and 2017 mileage and fuel consumption data.

Utilizing the projected but as yet un-adopted fleet replacement schedule, the fuel consumption and resulting demand for natural gas has been estimated. Table III. Projected Vehicle Natural Gas Usage – Fully Implemented provides a summary of the volume of anticipated natural gas demand during initial fleet replacements to CNG through full implementation to CNG as of 2027. This information can be shared with FNG in the event a CNG project moves forward. An MCF is equal to 1,000 cubic feet of natural gas.

Table III. – Projected Vehicle Natural Gas Usage – Fully Implemented

Fiscal Year	Fixed Route CNG Buses	Paratransit CNG	Monthly MCF	Annual MCF
2020	4	2	450	5,404
2021	3	2	803	9,636
2022	3	1	1,126	13,511
2023	0	0	1,126	13,511
2024	0	1	1,156	13,868
2025	0	1	1,185	14,225
2026	3	3	1,568	18,814
2027*	2	0	1,763	21,159
*** Entire Fleet Operating on CNG**				

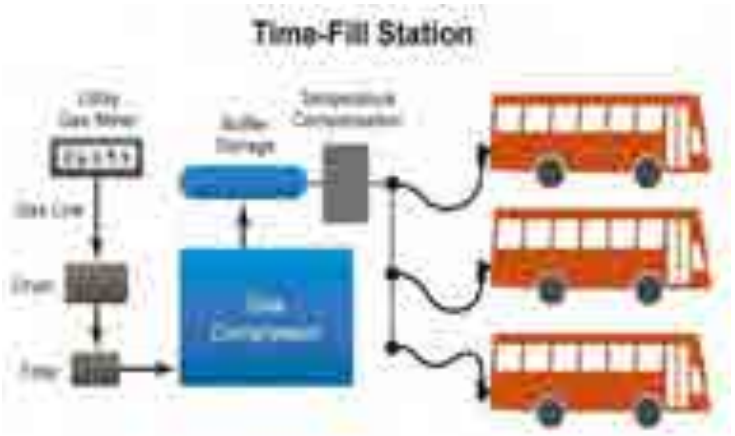
D. CNG Fueling Station

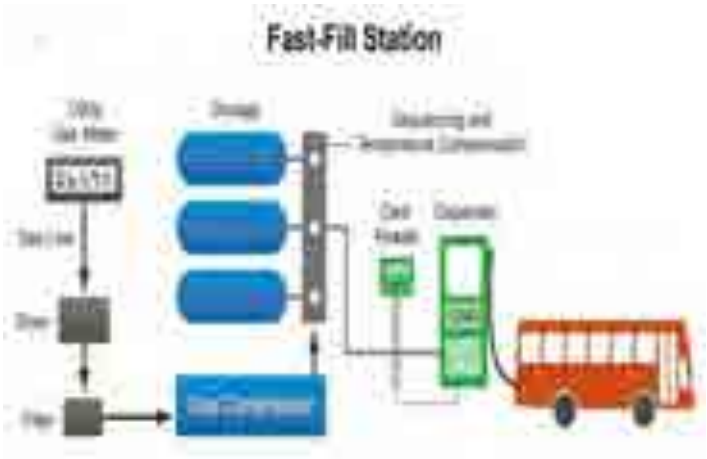
The biggest challenge to natural gas use for transportation overall is fleets cannot convert their vehicles without a place to fuel, and fueling stations require significant upfront capital

investments. In order for natural gas vehicles to be feasible for transit operations, fuel must be readily available and convenient.

1. Fueling Station Type

An analysis of fueling requirements was conducted for full implementation of the current fleet replacement for MACS and Van Tran identified in Table I. and referenced in Appendix A-1. There are typically two types of CNG stations, time-fill and fast-fill (see diagrams right). The main structural differences between the two systems are the amount of storage capacity available and the size of the compressor(s). These factors determine the amount of fuel dispensed and time it takes for CNG to be delivered. Drivers filling up at a fast-fill station experience similar fill times to a conventional fueling station. Because of the equipment requirements for more rapid fueling, fast-fill is also a more expensive option to implement. The option of a time-fill CNG station was examined and also found to not be feasible. This is primarily due to the daily fueling requirements and operational logistics including future probing, cleaning, fluid checks and other necessary end of day service requirements occurring at the service lane. Based on the transit operating characteristics and constraints at FNSB, we are suggesting a cascade type fast fill station. The system will be capable of dispensing 84 DGE or 96 GGE from storage without running the compressor(s).





2. Fueling Station Requirements & Location

The station requirements for this study are based on the recommended fleet replacement schedules referenced in Appendix A-1. This includes fueling 15 fixed route and 10 paratransit vehicles at full CNG implementation.

The compressors proposed are sized to handle this as well as the anticipated 10% planned growth and meet the current DGE fueling rates. A typical standard compressor package is rated at 72 decibels at 10 feet. An individual outside the fenced enclosure would typically be more than 10 feet away. Normal conversation can be heard at 3-5 feet when 70 decibels of environmental noise is present. Based on this criteria, and the proposed station location, the noise associated with compressor operations should not be detrimental to adjoining properties. Because the station is sized for evening operations there would be ample time throughout the daytime hours to fuel other Borough vehicles as well. Please note SCF refers to standard cubic feet, SCFM refers to standard cubic feet per minute, and GPM refers to gallons per minute. The station consists of two 230 SCFM compressors each paired with 100 HP electric motors. Table IV. Maximum Hourly Natural Gas Requirements illustrates typical fueling rate comparisons for CNG versus diesel and gasoline liquid fuels, including the comparison for the 230 SCFM sized for the FNSB design.

Table IV. - Maximum Hourly Natural Gas Requirements

Equivalent	SCF	Equivalent	SCF
Diesel Gallon	**143.94**	**Gasoline Gallon**	**126.67**
Requirement	**SCFM**	**Requirement**	**SCFM**
# 1.6 GPM	230	# 1.8 GPM	230
# 3.2 GPM	460	# 3.6 GPM	460
5 GPM	720	5 GPM	635
6 GPM	863	6 GPM	762
7 GPM	1,008	7 GPM	889
8 GPM	1,152	8 GPM	1,016
Maximum Hourly	SCF	Maximum Hourly	SCF
Output @ 5 GPM	43,200	Output @ 5 GPM	38,100
Output @ 6 GPM	51,780	Output @ 6 GPM	45,720

#Note: The FNSB system is designed to operate one 230 SCFM compressor at a time with the second compressor as a redundant unit. As illustrated in Table IV Maximum Hourly

Natural Gas Requirements, without using any of the designed storage capacity, at 1.6 DGE per minute 48 DGE can be delivered in 30 minutes or 96 DGE per hour. As stated earlier in the report the current hourly fueling demand ranges from 60-85 DGE fueling 2 buses per hour. Compressors are programed to operate alternatively but could also be set up to run concurrently during high demand to provide double this volume.

3. CNG Compressor Compound

As part of the overall project design a compressor compound location has been chosen that would sit outside the new operations and maintenance building service lane. This location offers the least impact to parking, bus flow and operations on the site and allows for an outdoor fueling dispenser as a backup. The CNG compound will be located outside, adjacent to the building, but a minimum distance of 10ft must be maintained to satisfy NFPA 52 (Vehicular Natural Gas Fuel Systems Code) clearance requirements. The preliminary compound approximately 53 feet long and 25 feet wide. The layout is illustrated in Appendix Exhibit A-4.

The main mechanical equipment within the station compound would consist of a manually regenerated single vessel natural gas dryer, two (2) 230 SCFM 100HP natural gas compressors, a bank of three (3) stacked 23' ASME CNG storage vessels, priority panel, electrical switchgear, and other necessary equipment. The entire compound would be protected by bollards. A provision is included for an emergency backup generator. This suggested layout is preliminary in nature and would be subject to final design requirements and approvals.

Based on the rate and volumes of fueling over the evening shift a cascade type fast-fill system is recommended. The three (3) storage vessels are utilized to provide the best fill possible on a vehicle. Natural gas is unlike a liquid fuel where you pump it in until the tank is full. When gas transfers between tanks the pressure equalizes over that volume. A cascade fill system is separated into 3 different types of storage tanks. Although all the tanks are physically the same, they are labeled the high-bank, mid-bank and low-bank. Each tank is piped separately through a priority panel. This panel contains the logic to use the

storage systematically to maximize the usable volume as well as provide each vehicle with a full fill. Using this approach multiple vehicles can be filled before the compressor is required to start up. Typically the logic within the system will have a set point on the low-bank and start up the compressor when the volume of the low bank reaches a preset amount.

The cascade system for this application allows fueling to occur from storage until such time that the compressor is needed. The compressor is able to be sized smaller because of the known fueling duration. The compressor will run to refill storage and keep running as vehicles continue to fill and draw off of storage. At a minimum, the compressor will run for nearly an hour just to fill the storage from the first few fills. As more vehicles continue to fill, the run time will keep extending. This design approach allows ample time between vehicles to ensure that the compressor does not short cycle.

Based on the fleet size, fueling duration and gas pressure available, we have determined that a 230 standard cubic feet per minute (SCFM) compressor will be sufficient to handle the demand. A second compressor will provide redundancy so fueling can continue in the event a compressor is down for maintenance or repair. Compressors are programed to operate alternatively but could also be set up to run concurrently to provide additional throughput if demand requires.

The compressors are paired with a bank of 3 horizontally stacked 23 foot long ASME storage vessels. The vessels hold 34,713 SCF of gas at @ 4500 PSI. Because of the pressures required for a full fill on the vehicle, the usable storage for fueling is 35% or 12,150 SCF of usable storage. That is an equivalent of 84 DGE or 96 GGE of fill from storage without starting a compressor. A priority panel provides the logic to accept incoming gas from compressors, refill storage appropriately on a priority basis, and provide a cascade fill to the dispenser when a vehicle is calling for fuel. This panel is central to the compressors, storage and dispensers and is responsible for ensuring the system is fueling properly. The dispenser will be located indoors and have two hoses. One for large transit buses and a second smaller style connection for cutaway paratransit buses and other light to medium duty vehicles. This two hose dispenser will provide the flexibility for multiple types of vehicles. A backup dispenser will be provided outside next to the compound.

Prior to gas entering the compressor, it typically passes through a natural gas dryer. Although the dry gas analysis shows 0.000 moisture, sending dry gas into the compressor is crucial for compressor performance and longevity. Water can cause major damage through freezing and the lack of ability to compress if it gets into the pistons. Even though a manually regenerative dryer may never need to be regenerated, it makes sense to include the component in the system to ensure successful operation. This also provides for the contingency that a typical pipeline gas distribution system comes later as opposed to the Liquefied Natural Gas (LNG) that is being vaporized and provided to distribution at this site.

The addition of an emergency backup generator should be considered for the project. A 180 kilowatt (kW) generator to operate only one compressor is estimated to add $121,650 in equipment costs. This insures that the critical vehicle fueling operations are not disrupted in emergency situations.

CNG Station Cost Estimate

The high level opinion of probable cost for the CNG Station is estimated to be $2,175,722. The detailed cost estimate is attached to this report. The major cost components are:

a. CNG Compressor* Compound - $ 1,048,200

b. Fueling Systems Electrical - $186,626

c. Project Design, Construction, Contingency, etc. - $940,896

E. Projected Diesel, Gasoline and Natural Gas Costs

Estimating future diesel prices for 2018 and beyond in Alaska is highly uncertain. As excess supplies and global and United States oil production have lowered prices, most of the lower 48 states benefit from fuels refined from cheap crude oil from Texas or western Canada. Alaska's in-state refining uses relatively pricey Alaska North Slope crude, and out-of-state sources must take a long, expensive shipping route to Alaska. This typically causes higher fuel prices and more price volatility.

The transit system does not pay federal or state fuel taxes. In an effort to reduce America's dependence on foreign oil, reduce urban emissions and reduce greenhouse gases, the federal government offers a number of tax incentives to encourage the use of natural gas vehicles including a 50-cent tax credit per gasoline gallon equivalent (GGE) of compressed natural gas (CNG). The credit went into effect October 1, 2006 and originally expired December 31, 2009. Congress has extended this credit several times. The most recent extension of this incentive ended December 31, 2017 and was not extended beyond that in the recent tax bill. Although not a part of this financial analysis, if this provision were to be extended again in the future addition savings in annual fuel costs would be realized.

For the purposes of financial analysis we have reviewed the projections from the U.S. Energy Information Administration (EIA). The last Annual Energy Outlook 2018 (AEO2018) prepared by EIA was released in February 2018. The EIA presents a number of scenarios for future fuel cost projections with the EIA's normal or middle of the road "Reference Case" projecting average annual increases of 3.5% for gasoline and 3.7% for diesel through 2050. Projections show a steeper upward trend for both gasoline and diesel between 2018 and 2025 with the nominal price for both fuels increasing $1.40 - $1.50 a gallon. It is difficult to judge among the differing EIA scenarios and we have applied a conservative 2% annual inflation rate to both diesel and gasoline prices in the financial payback scenario. Using a projected 2020 price of $2.95 a gallon for diesel in Fairbanks and applying a 2% annual inflation rate results in a fiscal year 2039 projected price of $4.29 a gallon. A projected 2020 price of $3.25 a gallon for gasoline in Fairbanks with a 2% annual inflation rate applied results in a fiscal year 2039 projected price of $4.74 a gallon for gasoline.

Based upon AEO2018 natural gas production accounts for nearly 39% of all U.S. energy production by 2050. Natural gas production increases in every case projection, supporting higher levels of domestic consumption and natural gas exports. The U.S. is projected to become a net energy exporter by 2022. Henry Hub prices in the AEO2018 Reference case are 14% lower on average through 2050 than in the AEO2017 projections. EIA projects natural gas prices will continue to remain less expensive than gasoline or diesel fuel for the foreseeable future. Despite all this positive pricing information, natural gas prices in Fairbanks presents a special case. Currently there is no major pipeline supplying Fairbanks therefore all gas is shipped in as LNG and provided to the end user after vaporization. For

purposes of pricing we have relied on the Interior Gas Utility 2018 Financial Forecast and Pro Forma projected rates through 2031 documentation provided by Fairbanks Natural Gas. We have left the projected price unchanged from 2032 to 2039.

F. CNG Diesel/Gasoline Gallon Equivalent (DGE/GGE) Cost

Gasoline and diesel fuel are dispensed and sold on a liquid gallon basis. Compressed natural gas as a transportation fuel is sold on a gasoline gallon equivalent (GGE) basis. There is not an adopted standard for the dispensing of a diesel gallon equivalent (DGE). On a liquid gallon basis, diesel fuel has a higher energy content per gallon than unleaded gasoline. Natural gas as a commodity is priced on a 1000 cubic foot (MCF) or alternatively on a dekatherm (DTH) basis. A DTH is a unit of energy equal to 10 therms or one million British thermal units (MMBtu). There is approximately 1000 cubic feet in a dekatherm. A GGE of compressed natural gas is equal to 126.67 cubic feet of natural gas. A DGE of compressed natural gas is equal to 143.94 cubic feet. To more accurately reflect the cost comparison of the fuels, we have used a buildup approach to the cost per DGE of the CNG fuel. The DGE cost is based on natural gas cost, CNG equipment maintenance reserve, drying and compression costs.

The following Table V. CNG Cost Breakdown per DGE/GGE illustrates the breakdown of the estimated fiscal year 2020 initial baseline built-up CNG cost per DGE/GGE for the 20 year financial scenarios.

Table V. - CNG Cost Breakdown per DGE/GGE

Component	DGE	GGE
1. Natural Gas	$2.74	$2.42
2. Maintenance Reserve	$0.20	$0.18
3. Drying and Compression	$0.17	$0.15
Total Cost	**$3.11**	**$2.75**

1. Natural Gas Cost

The charge per MCF (1,000 cubic feet) of natural gas is $19.07 in FY20 as provided by the Interior Gas Utility. Prices for natural gas remain relatively flat throughout the 20 year scenario. One MCF contains approximately 6.95 diesel gallon equivalents (DGE) and 7.89 gasoline gallon equivalents (GGE).

2. Maintenance Reserve

The CNG fueling facility maintenance costs typically are based upon a gallon equivalent cost. Industry average maintenance costs run anywhere from $0.15 to $0.30 per gallon depending on the size and complexity of the station. This cost allocation covers the annual maintenance recommended by the manufacturer as well as the periodic overhauls of the compressors. Typical costs for this smaller size station proposed in this study are estimated to be $0.20 per DGE and $0.18 per GGE. It should be noted that this is not an annual expenditure but a maintenance reserve fund that would be set aside to fund periodic and future equipment maintenance. A MACS vehicle consuming 8,125 DGE of CNG would allocate an equivalent of $1,625 and a Van Tran vehicle consuming 2,821 GGE would allocate $508 per year towards current and future maintenance. Once CNG is fully implemented approximately $30,000 per year could be allocated for station maintenance using this approach.

3. Drying and Compression

Drying and compression typically includes the energy costs to run the station, primarily electric. This cost would typically be in the $0.10 - $0.15 per GGE/DGGE range. The Fairbanks electrical provider Golden Valley Electric Association (GVEA) has a higher $0.25 per kilowatt hour rate. We estimate this cost to be $017 per DGE and $0.15 per GGE. Operating the station in the evening has no impact as rates are unchanged by time of day.

G. CNG Safety, Specialized Training and Maintenance

Any fuel, including those used in motor vehicles, can be dangerous if handled improperly. Fuels contain energy, which is released when the fuel is ignited. Gasoline is a potentially dangerous fuel, but, by understanding how to handle it, we have learned to use it safely. The same is true of natural gas. Natural gas safely generates our electricity, heats our homes and cooks our meals. But, like gasoline, natural gas must be understood and respected in order to be used safely.

Natural gas is fuel that occurs naturally and requires very little processing before use. Chemically it normally consists of over 90% methane with smaller amounts of ethane, propane, butane, carbon dioxide and other trace gases. Pure methane has a very high octane rating (120-130) and the high methane content of natural gas in turn gives natural gas this same attribute. As with all vehicle fuels, natural gas can be used safely if the unique properties of the fuel are understood and common sense procedures are followed. In fact, natural gas has safety advantages compared to gasoline and diesel: it is non-toxic, and has no potential for ground or water contamination in the event of a fuel release.

Natural gas is lighter than air and dissipates rapidly when released. An odorant is added to provide a distinctive and intentionally disagreeable smell that is easy to recognize. The odor is detectable at one-fifth of the gas' lower flammability limit. Natural gas vehicles have an excellent safety record for two primary reasons: the properties of the fuel itself and the integrity of the natural gas vehicle and its fuel delivery system. Natural gas has a very limited range of flammability – it will not burn in concentrations below about 5% or above about 15% when mixed with air. Gasoline and diesel burn at much lower concentrations and ignite at lower temperatures.

Like conventional vehicles, CNG vehicles require proper maintenance. It is important to have trained technicians to properly maintain and service CNG vehicles. Because of the unique aspects of high pressure gas, the specialized equipment and the best practices required when transitioning to the CNG fuel source, additional training in the area of CNG fuel storage and fuel systems is recommended. Original equipment manufacturers generally fully back

the vehicles they produce with standard warranties, adequate parts inventory, and trained technicians available to assist you as needed. As CNG vehicles are introduced into the fleet, additional targeted CNG engine diagnostic and maintenance training will be a benefit to on-going operations. Overall training regimens for CNG vehicles should be continuous and on-going. It is recommended that continuing education and training programs be developed to reinforce any new standard operating procedures and safety requirements necessary for CNG vehicles.

1. Specialized CNG Training

A variety of training resources are available for compressed natural gas vehicles. A good source for training is the Natural Gas Vehicle Institute (NGVi). A variety of courses with various tuition fees (2018 early bird rates) are offered including: Level 1: NGV Essentials and Safety Practices $655, Level 2: CNG Fuel System Inspector Training $1,055, Level 3: Heavy-Duty NGV Maintenance and Diagnostics Training $1,695, and Essentials of CNG Station Operation and Maintenance $895. NGVi also provides the CNG Fuel System Inspector Certification Exam for $295 and is valid for a period of five years. More information can be found online at http://ngvi.com/public_registration.html. Most classes are 1-2 days and are offered in various locations. Not included in these fees are airline fares, hotel accommodations, and other travel expenses.

An important consideration and a vital part of fleet safety is ensuring the integrity of CNG storage and fuel systems. The National Highway Transportation Safety Administration (NHTSA) requires all on-board CNG storage cylinders manufactured after March 1995 be visually inspected every three years or 36,000 miles whichever comes first. The useful life of a CNG cylinder is dependent on the number of years it has been certified. Most CNG cylinders for onboard fuel storage are certified to either 15 or 20 years as per NGV2. In addition, cylinders should be inspected following any accident.

It would be recommended that you initially designate an adequate number of maintenance employees to work on CNG storage and fuel systems and have those employees receive CNG Fuel System Inspector training and certification before or

immediately after vehicles arrive and are put in service. As noted above the time required for this would generally be a one and a half to two day class and a certification exam. As a longer term strategy the consideration of modifying or adopting a new job classification such as "Fuel System Specialist" for vehicle inspections and/or a "Fueling System Technician" with training focused on maintaining the fueling station compression and dispensing equipment could be considered. Additional sources of information can also be found online or through networking with peer systems who have operated CNG transit fleets.

2. Vehicle Maintenance

Costs associated with a heavy duty dedicated CNG engine versus an equivalent diesel engine has narrowed. Although there is not good published data, it is generally accepted that the cost of maintaining a CNG engine is slightly higher than a pre-2010 diesel engine. The costs are similar however when compared to a post 2010 diesel engine and the increased maintenance requirements due to the 2010 EPA requirements. At the time of this study, there is not a large amount of additional reliable cost data to validate true maintenance costs of CNG versus diesel engines. Many published articles suggest little or no cost difference when coupled with good maintenance practices. We found no reliable data published for transit operations and have projected no additional costs for CNG vehicle maintenance in the feasibility cost model.

Dedicated natural gas engines in medium and heavy-duty diesel powered vehicles change from compression ignition to spark-ignition. Overall, maintenance for the ISL-G Cummins dedicated natural gas engine is similar to that of diesel engines, but there are a few key differences. Spark plugs will need to be replaced per the original equipment manufacturers recommended maintenance schedules. Motor oil specifically formulated for natural gas engines is required. If diesel engine oil is used, valve torching, piston scuffing and reduction in spark plug life will occur. For the ISL G, valve adjustment must be performed at intervals recommended by the engine manufacturer. This is an important step in achieving longer engine life.

Because the ISL-G does not require a Diesel Particulate Filter (DPF) or Selective Catalytic Reduction (SCR) systems, operators do not need to perform re-generations, and Diesel Exhaust Fluid (DEF) is not required. The fleet should save money by eliminating diesel emissions fluid, and diesel particulate filters and the regeneration issues sometimes accompanying the system with idling and low vehicles speeds. In the longer term, newer CNG engines have reduced maintenance requirements over their predecessors. In the case of the heavy duty transit vehicle, Cummins generally provides on-site training as required for mechanics maintaining the ISL-G engine that would be utilized in the buses.

Similarly light duty small and mid-sized buses are already spark ignition engines with natural gas conversions provided at a certified factory installation facility approved by Ford and General Motors. As such these vehicles carry all the same warranties as a gasoline vehicle. With the exception of the fuel storage system, general repairs procedures are substantially similar.

3. CNG Station Maintenance and Training

Like any other equipment, CNG station equipment requires preventive and corrective maintenance. Regular station maintenance will help prevent larger costs in the future. The station manufacturer will provide a comprehensive inspection and preventive maintenance program for the station equipment. The maintenance may be performed by facilities staff or be contracted to a third-party service provider. Although generally included, it is recommended that the transit system require the CNG station manufacturer provide on-site training on equipment to designated facilities staff, mechanic(s) or fueling system technician(s) that will include all maintenance and operations requirements for the station. Designated staff should work with a station trainer during initial station start up to understand all the required maintenance and operations requirements. After a station has been successfully in operation a few months, it is also recommended that the same staff receive training on EPA, MPCA, and local rules and regulations. Training consisting of 3-5 days of classroom and technical

training on compressor and fueling station system maintenance (if available) at the compressor manufacturing plant or training center is also encouraged. If the transit system wants this included in the procurement, it can be required at the time the specifications are issued for a station.

H. Environmental Benefits of CNG Vehicles

Fairbanks has the highest recorded levels of fine particulate matter ($PM_{2.5}$) in the nation. Its 2012–2014 design value is 139 µg/m3, which is 400% above the 35 µg/m3 National Ambient Air Quality Standard (NAAQS). No other community in the country has a greater air quality problem. The U.S. Environmental Protection Agency (EPA) reclassified the Fairbanks North Star Borough $PM_{2.5}$ nonattainment area from a Moderate to a Serious Area with an effective date of June 9, 2017. The reclassification by EPA triggered a requirement for the Alaska Department of Environmental Conservation (DEC) to update the area's State Implementation Plan (SIP) to include additional control measures that can be implemented to improve air quality.

The challenge of identifying, funding, and committing to implement the controls needed to produce the reduction required to attain the ambient $PM_{2.5}$ standard is huge. The severity of Fairbanks' air quality problem can be directly affected by the implementation of the transit bus CNG infrastructure project that will reduce directly emitted $PM_{2.5}$ and related precursor pollutants.

Information presented in the Reasonable Available Control Measure (RACM) analysis for the Moderate PM $PM_{2.5}$ SIP documented that home heating expenses in FNSB are two to three times higher than those seen in any other community with wood-burning controls. Unlike many communities, FNSB has limited access to natural gas and the dominant source of residential heating is fuel oil, which has had volatile price swings in recent years. While Fairbanks currently has natural gas service, it is capacity constrained; fewer than 400 homes currently heat with gas. Recognizing the need to provide a low-cost lower-emitting fuel alternative, the Alaska Industrial and Development Export Authority (AIDEA) and Interior

Gas Utility (IGU) Boards agreed to initiate construction of a 5.25 million gallon LNG tank to expand service to residential consumers starting in 2020. Construction on the project foundation began in January 2018 and has progressed rapidly. As of March 31, 2018, the foundation site was excavated and backfilled, and a thermos-syphon system was installed to maintain an appropriate ground temperature below the facility. Most recently, reinforcement steel has been placed and foundation forms constructed in preparation of pouring cement. The LNG storage project has a target completion date of fall 2019. Separate efforts have focused on ensuring long-term gas supply, liquefaction, transportation and distribution requirements. The IGU and AIDEA are also evaluating opportunities for supplying gas to local utilities and motor vehicles.

The Fairbanks Metropolitan Area Commuter System (MACS) is an integral part of the Fairbanks Metropolitan Area Transportation System (FMATS) and its efforts to enhance mobility in the community. It is also one of the control measures specified in the moderate area PM2.5 SIP. FNSB currently operates fifteen (15) heavy duty diesel transit buses for the MACS nine (9) fixed routes and a total of ten (10) E-350 and E-450 Ford cutaway chassis gasoline powered buses for the Grey Line and Van Tran paratransit demand response ADA service. An emissions analysis of converting these vehicles to CNG was prepared according to the recommended bus replacement plans specified in Appendix A-1.

The MACS vehicles have longer lifetimes than the Grey Line and Van Trans paratransit vehicles which results in more replacement cycles to cover comparable periods of operation. EPA's MOVES2014b model was used to generate the gram/mile emission factors for existing diesel and gasoline vehicles and replacement CNG vehicles in Appendix A-1. These values were combined with Borough supplied annual mileage values for each of the vehicles being replaced to quantify before and after emission estimates for the lifetime of each vehicle. The difference between these values was used to quantify the emission benefits of replacement. The final projected emission reduction results are presented in Exhibit A-8 and are summarized in Table VI. Expected Lifetime Benefits from CNG Vehicle Replacements on page 3-29 listing the separate pollutant (i.e., $PM_{2.5}$, VOC, CO and NOx) reductions for the MACS diesel powered buses and the gasoline powered Van Tran vehicles. The net benefit of replacing both vehicle fleets is also presented. As can be seen, significant

reductions are achieved for each of the criteria pollutants, which will aid Fairbanks maintain compliance with the ambient 8-hour CO standard (and related Maintenance Plan) and contribute reductions needed to aid compliance with the ambient 24-hour ambient $PM_{2.5}$ standard (a serious SIP is currently under development).

It should be noted that the estimates do not account for the principal benefit of transit service, which is the elimination of low-occupancy light-duty vehicle trips. In Alaska, gasoline-powered light-duty vehicles are a significant source of emissions because of the impact of arctic temperatures on cold-start emissions.

Table VI. - Expected Lifetime Benefits from CNG Vehicle Replacements (Total Tons)

Bus Fleet	$PM_{2.5}$	VOC	CO	NOx
Diesel – 15 Vehicles	0.242	0.672	-20.266	21.196
Gasoline – 10 Vehicles	0.107	2.394	41.299	0.706
Total Benefit	**0.348**	**3.065**	**21.033**	**21.902**

CNG vehicles also provide positive environmental aspects in reducing carbon dioxide (CO_2) emissions. The CO_2 emission coefficients of different fuels can be found on the U.S. Energy Information website:
http://www.eia.gov/environment/emissions/co2_vol_mass.cfm
The following a comparison of fuels relevant to this feasibility study. The following are the carbon dioxide emission coefficients by differing fuel types.

Carbon Dioxide Emission Coefficients

- **Natural Gas = 119.9 pounds per 1000 cubic feet (MCF)**
- **Natural Gas = 15.2 pounds per GGE**
- **Gasoline = 19.6 pounds per gallon**
- **Natural Gas = 17.3 pounds per DGE**
- **Diesel Fuel = 22.4 pounds per gallon (ultra-low sulfur)**

A gasoline gallon equivalent (GGE) is 126.67 cubic feet of natural gas. A diesel gallon equivalent (DGE) is 143.94 cubic feet of natural gas. A metric ton is 2,200 pounds. Each gallon of gasoline replaced with CNG represents a 4.4 pound or approximately 22.5% reduction in greenhouse gas emissions. Each gallon of diesel replaced with CNG represents a 5.14 pound or approximately 23% reduction in greenhouse gas emissions.

Each heavy duty CNG transit bus operated on CNG is projected to eliminate the use of 8,145 gallons of diesel annually. Replacing this with natural gas, the net impact is an annual reduction of 19 metric tons of CO_2 per bus. The annual reduction of 19 metric tons of CO_2 is equivalent to the annual greenhouse gas emissions (GHGE's) from 6.6 tons of waste sent to the landfill, the CO_2 emissions from 20,788 pounds of coal burned, the electricity use for 2.1 homes for a year, or the carbon sequestered by 492 tree seedlings grown for 10 years.

Over the life of the 20 year study period, dedicating all planned future large transit bus purchases to CNG operations results in displacement of 2,109,555 gallons of diesel resulting in a net Greenhouse Gas Emissions reduction of 4,929 metric tons of CO_2.

Each Van Tran cutaway CNG transit bus operated on CNG eliminates an average of 2,821 gallons of gasoline annually. Replacing this with natural gas, the net impact is an annual reduction of 5.65 metric tons of Carbon Dioxide (CO_2) per bus. The annual reduction of 5.65 metric tons of CO_2 is equivalent to the annual greenhouse gas emissions (GHGE's) from 2 tons of waste sent to the landfill, the CO_2 emissions from 6,182 pounds of coal burned, the electricity use for 1 homes for a year, or the carbon sequestered by 146 tree seedlings grown for 10 years.

Over the life of the 20 year study period, dedicating all planned future small cutaway transit bus purchases to CNG operations results in displacement of 476,749 gallons of gasoline resulting in a net Greenhouse Gas Emissions reduction of 955 metric tons of CO_2.

The combined MACS and Van Tran fleets operating on CNG over the 20 year study period results in a reduction of 5,884 metric tons of CO_2 or the equivalent annual greenhouse gas emissions (GHGE's) from 2,050 tons of waste sent to the landfill, the CO_2 emissions from 6,437,637 pounds of coal burned, the electricity use for 635 homes for a year, or the carbon sequestered by 152,491 tree seedlings grown for 10 years.

Findings

A life cycle analysis provides an economic analysis of the proposed capital investments that are expected in order to provide CNG vehicles while recognizing the change in operating costs of both the facilities and fleet. The long term financial analysis of return on investment demonstrates the capital outlays necessary to make facilities CNG ready, spend the additional resources to procure CNG fueled vehicles as outlined in the study, and build fueling station infrastructure. If the Borough goes ahead with the fleet transition to CNG it is recommended that the transit system construct a station on site. The most feasible location for a CNG station for operations is being determined by the current design process.

The 20 year financial feasibility of the switch to CNG vehicles is virtually cost neutral with full fleet implementation when CNG vehicle upcharges are included and facility and CNG station costs are excluded. When these costs are included in year one of the financial scenario, the 20 year net cash flow is -$2,730,873. The following is a recap of project costs and savings:

A. Project Costs and Savings

Table VII. Recap of CNG Fuel Savings vs. Increased Bus Costs and Table VIII. Facility and CNG Station Costs summarize the significant CNG costs/savings noted in the report.

Table VII. - Recap of CNG Fuel Savings vs. Increased Bus Costs

Category	Fuel Savings Utilizing CNG vs. Diesel /Gasoline	Less Added Bus Costs for CNG Engine, Fuel System, Tanks	* 20 Year Net Savings After CNG Bus Upcharges
Overall CNG Program	**$1,438,959**	(-$1,422,454)	**$16,504**
MACS Bus Fleet	$872,248	(-$891,311)	(-$19,063)
Van Tran Fleet	$566,711	(-$531,143)	$35,568

* Does Not Include Facility or CNG Fueling System Cost Estimates Listed Below.

Table VIII. - Facility and CNG Station Costs

Recommended	Equipment and Construction	Contingency and Other Project Costs	Total Estimate
Maintenance Repair, Indoor Fueling, Storage Upgrades	$371,419	$200,237	$571,656
CNG Fueling Station	$1,234,826	$940,896	$2,175,722

B. Cash Flow / Net Present Values

The annual cash flows are calculated as the net of capital outlays, increased vehicle costs, vehicle maintenance costs and projected fuel savings. The Net Present Value (NPV) of a project is determined by the summation of all annual cost savings (inflow cash) and all annual debts (outflow cash) over the life of the project stated in current dollars.

The total annual expenditure (savings & costs) is brought back to a present worth using a discount rate and is shown in the Cash Flows tables, which can found in the Appendix at the end of this study. A discount rate is defined as, "The rate of return required by an investor to accept the risks of a certain investment." This rate typically includes the inflation cost of money and the potential "risk-free" investment an owner could make. This rate differs based on the individual owner, their standard practice, and their tolerance for risk. Traditionally, this rate is typically greater than inflation. For the purpose of this analysis, a rate of 2.5% is assumed. The internal rate of return calculation is used for a series of cash flows represented by the numbers in values. These cash flows do not have to be even, and may be negative or positive based on net expenditures versus revenues. Cash flows must occur at regular intervals, such as annually in our case. The internal rate of return (IRR) is the interest rate received for an investment consisting of payments (negative values) and income (positive values) that occur at regular periods.

The project cash flow analysis scenarios include estimated capital outlays for the increased cost of CNG buses, necessary facility upgrades to meet CNG bus requirements for the maintenance repair, indoor fueling and service and bus storage areas, and construction of a new fast-fill CNG station. The Initial finding is that there are overall positive cash flows from conversion to CNG with the combined MACS and Van Tran scenarios when CNG vehicle upcharges are accounted for facility and fueling station costs are NOT assigned the CNG vehicle upcharges.

The Appendix contains the recommended fleet replacement schedules and fuel cost projections used for the separate cash flow analysis spreadsheets. A variety of scenarios are presented in this report demonstrating the net effect of CNG vehicle upcharges and fuels savings with and without the CNG facility and CNG fueling station costs.

Recommendations

The Borough requests a recommendation for future use of CNG at the Borough Transit Garage facility. The recommendation was to review the following options: 1) do not convert, 2) implement in the future, or 3) convert as part of the current project. Wendel recommends the Borough consider Option 2 with a few caveats. The Borough should consider the benefits of a future fleet wide implementation of CNG bus operations. Federal Transit Administration (FTA) and/or State of Alaska grant funding could be sought to cover the cost of the remaining requirements for a CNG compliant facility and CNG fueling station as part of the funding for Phase 2. With an initially well designed maintenance building, the required changes to make the facility CNG compatible are very reasonable for this project scope. In the short term it is advised the Borough proceed with Phase 1 design using the guidance provided in this report to have a facility that is easily upgraded in Phase 2 for overall CNG compliance. The following costs/items should be included in Phase 1:

1. Option A - Entire repair facility CNG compliant.
    a. $ 26,400 - added cost for 6 CNG compliant tailpipe exhaust reels
2. Fueling and service lane CNG compliant.
    a. $30,000 - compartmentalized fueling area - 2 Hour CMU End Wall Enclosures.
    b. $20,955 - Class 1, Division 2 (explosion proof) compliant wiring and lighting.
    c. NFPA 52 - 2016 update no longer requires deflagration panels. The Borough will need to adopt this code revision and get consensus with the Authorities Having Jurisdiction to determine if this will be required. If required, an estimate for the deflagration system would need to be prepared based on an approved design.

The total Phase 1 items recommended equal $77,355. For budgeting purposes additional project design, construction contingency, contractor fees and general conditions of $46,413 can be added for a total of $123,768.

Depending on the location of future installations of methane detection and controls it may be advisable to oversize conduit used for carbon monoxide (CO) and nitrogen dioxide (NO_2) monitoring as an alternative to running separate methane detection conduit in Phase 2. In regard to future emergency exhaust fan systems for the repair and fueling areas, future locations should be documented and adequate spacing provided between roof joists in the Phase 1 design and construction.

In the event CNG operations are started before Phase 2 is built, then the additional items including emergency exhaust fan systems and methane detection for the repair and fueling areas as well as the and the two hour rated coiling overhead doors for the fueling area would need to be installed before CNG buses arrive.

The move to begin transitioning the transit fleet to compressed natural gas (CNG) also warrants consideration as an environmental enhancement to vehicle use in transit operations. Again, the recommended strategy would be to buy new CNG transit buses as the older buses are replaced. The reliability of new heavy duty CNG transit buses has continued to improve. The introduction of new CNG engines, improved technology, and more reliable storage and dispensing systems has improved the operations and maintenance experience in all climates.

The business case analysis in this study comparing operations with CNG to diesel and gasoline provides positive fuel cost savings and reduced greenhouse gas emissions. The additional capital investments for the CNG facility upgrades and CNG station should be considered carefully in light of the other benefits. Securing additional grant funds for these upfront capital expense would be helpful to the overall project.

Because of the higher cost of natural gas in Fairbanks compared to the lower 48 states, the projected $2,840,392 cost for the facility upgrades and CNG station would likely not be covered by fuel savings unless natural gas prices were lowered or diesel and gasoline prices escalate further in which case the fuel cost savings could improve significantly. For example: in the 20 year scenario an $0.88 increase in the 2020 baseline diesel and gasoline price with 2% annual inflation generates the necessary fuel cost savings for the project to break even. Natural gas prices are projected to continue to remain very stable long term and could come down with an increase in Fairbanks natural gas users or the availability of pipeline gas to the Fairbanks area.

Should a decision be made to move ahead, strategic discussion with stakeholders and partners including the natural gas and electric providers, and bus manufacturers/small bus dealers should be undertaken early to insure infrastructure is adequately planned. A dedicated, on-site, fast-fill CNG fueling system is preferred. With the nine month to one year timeframe required to order and construct a CNG station, caution should be taken to ensure

that fueling station infrastructure is operational and coordinated with when CNG transit buses are ordered, received and placed into service. Staff administration, operator, and maintenance training should also be planned and completed prior to the introduction of CNG vehicles to the fleet.

Appendix

APENDIX A-1

Fairbanks North Star Borough: MACS - Recommended 10 Year Bus Replacement Plan 2019-2028

Unit	Replaced	Year	LifeCycle	Replace	Make	Length	Model	2019 Due	2020 Due	2021 Due	2022 Due	2023 Due	2024 Due	2025 Due	2026 Due	2027 Due	2028 Due
71	---	2007	13	2020	Gillig	35	Low Floor	1	0								
72	---	2007	13	2020	Gillig	35	Low Floor	1	0								
73	---	2007	13	2020	Gillig	35	Low Floor	1	0								
74	---	2007	13	2020	Gillig	35	Low Floor	1	0								
710	---	2007	14	2021	Gillig	30	Low Floor	1	1	0							
75	---	2007	14	2021	Gillig	30	Low Floor	1	1	0							
76	---	2007	14	2021	Gillig	30	Low Floor	1	1	0							
77	---	2007	15	2022	Gillig	30	Low Floor	1	1	1	0						
78	---	2007	15	2022	Gillig	30	Low Floor	1	1	1	0						
79	---	2007	15	2022	Gillig	30	Low Floor	1	1	1	0						
141	---	2014	12	2026	Gillig	35	Low Floor	1	1	1	1	1	1	1	0		
142	---	2014	12	2026	Gillig	35	Low Floor	1	1	1	1	1	1	1	0		
143	---	2014	12	2026	Gillig	35	Low Floor	1	1	1	1	1	1	1	0		
Anch1	T945	2013	14	2027	New Flyer	40	Low Floor	1	1	1	1	1	1	1	1	0	
Anch2	T946	2013	14	2027	New Flyer	40	Low Floor	1	1	1	1	1	1	1	1	0	
144	71	2020	15	2035	Gillig	35	Low Floor		1	1	1	1	1	1	1	1	1
145	72	2020	15	2035	Gillig	35	Low Floor		1	1	1	1	1	1	1	1	1
146	73	2020	15	2035	Gillig	35	Low Floor		1	1	1	1	1	1	1	1	1
147	74	2020	15	2035	Gillig	35	Low Floor		1	1	1	1	1	1	1	1	1
148	710	2021	15	2036	Gillig	35	Low Floor			1	1	1	1	1	1	1	1
149	75	2021	15	2036	Gillig	35	Low Floor			1	1	1	1	1	1	1	1
150	76	2021	15	2036	Gillig	35	Low Floor			1	1	1	1	1	1	1	1
151	77	2022	15	2037	Gillig	35	Low Floor				1	1	1	1	1	1	1
152	78	2022	15	2037	Gillig	35	Low Floor				1	1	1	1	1	1	1
153	79	2022	15	2037	Gillig	35	Low Floor				1	1	1	1	1	1	1
154	141	2026	15	2041	Gillig	35	Low Floor								1	1	1
155	142	2026	15	2041	Gillig	35	Low Floor								1	1	1
156	143	2026	15	2041	Gillig	35	Low Floor								1	1	1
157	Anch1	2027	15	2042	Gillig	35	Low Floor									1	1
158	Anch2	2027	15	2042	Gillig	35	Low Floor									1	1
Vehicles Replaced								0	4	3	3	0	0	0	3	2	0
Total Vehicles								15	15	15	15	15	15	15	15	15	15
Required Peak								12	12	12	12	12	12	12	12	12	12
Spare Ratio								20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Per Vehicle Cost Diesel							Inflation Factor 2%	$ 490,196	$ 500,000	$ 510,000	$ 520,200	$ 530,604	$ 541,216	$ 552,040	$ 563,081	$ 574,343	$ 585,830
Per Vehicle Cost CNG Upcharge (Washington State Bid 2018)							CNG Upcharge $ 48,397	$ 538,593	$ 548,397	$ 558,397	$ 568,597	$ 579,001	$ 589,613	$ 600,437	$ 611,478	$ 622,740	$ 634,227
Note Only: Total Additional for CNG Upcharges								$ -	$ 193,588	$ 145,191	$ 145,191	$ -	$ -	$ -	$ 145,191	$ 96,794	$ -

Capital Improvement Plan - Annual Outlays	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Vehicle Replacement Cost Diesel	$ -	$ 2,000,000	$ 1,530,000	$ 1,560,600	$ -	$ -	$ -	$ 1,689,243	$ 1,148,686	$ -
Total Vehicle Replacement Cost CNG	$ -	$ 2,193,588	$ 1,675,191	$ 1,705,791	$ -	$ -	$ -	$ 1,834,434	$ 1,245,480	$ -
Local Share 20% Diesel	$ -	$ 400,000	$ 306,000	$ 312,120	$ -	$ -	$ -	$ 337,849	$ 229,737	$ -
Non-Local Share Diesel	$ -	$ 1,600,000	$ 1,224,000	$ 1,248,480	$ -	$ -	$ -	$ 1,351,394	$ 918,949	$ -
Local Share 20% CNG	$ -	$ 438,718	$ 335,038	$ 341,158	$ -	$ -	$ -	$ 366,887	$ 249,096	$ -
Non-Local Share CNG	$ -	$ 1,754,870	$ 1,340,153	$ 1,364,633	$ -	$ -	$ -	$ 1,467,547	$ 996,384	$ -

APENDIX A-1

Fairbanks North Star Borough: MACS - Recommended 10 Year Bus Replacement Plan 2029-2038

Unit	Replaced	Year	LifeCycle	Replace	Make	Length	Model	2029 Due	2030 Due	2031 Due	2032 Due	2033 Due	2034 Due	2035 Due	2036 Due	2037 Due	2038 Due
144	71	2020	15	2035	Gillig	35	Low Floor	1	1	1	1	1	1	0			
145	72	2020	15	2035	Gillig	35	Low Floor	1	1	1	1	1	1	0			
146	73	2020	15	2035	Gillig	35	Low Floor	1	1	1	1	1	1	0			
147	74	2020	15	2035	Gillig	35	Low Floor	1	1	1	1	1	1	0			
148	710	2021	15	2036	Gillig	35	Low Floor	1	1	1	1	1	1	1	0		
149	75	2021	15	2036	Gillig	35	Low Floor	1	1	1	1	1	1	1	0		
150	76	2021	15	2036	Gillig	35	Low Floor	1	1	1	1	1	1	1	0		
151	77	2022	15	2037	Gillig	35	Low Floor	1	1	1	1	1	1	1	1	0	
152	78	2022	15	2037	Gillig	35	Low Floor	1	1	1	1	1	1	1	1	0	
153	79	2022	15	2037	Gillig	35	Low Floor	1	1	1	1	1	1	1	1	0	
154	141	2026	15	2041	Gillig	35	Low Floor	1	1	1	1	1	1	1	1	1	1
155	142	2026	15	2041	Gillig	35	Low Floor	1	1	1	1	1	1	1	1	1	1
156	143	2026	15	2041	Gillig	35	Low Floor	1	1	1	1	1	1	1	1	1	1
157	Anch1	2027	15	2042	Gillig	35	Low Floor	1	1	1	1	1	1	1	1	1	1
158	Anch2	2027	15	2042	Gillig	35	Low Floor	1	1	1	1	1	1	1	1	1	1
159	144	2035	15	2050	Gillig	35	Low Floor							1	1	1	1
160	145	2035	15	2050	Gillig	35	Low Floor							1	1	1	1
161	146	2035	15	2050	Gillig	35	Low Floor							1	1	1	1
162	147	2035	15	2050	Gillig	35	Low Floor							1	1	1	1
163	148	2036	15	2051	Gillig	35	Low Floor								1	1	1
164	149	2036	15	2051	Gillig	35	Low Floor								1	1	1
165	150	2036	15	2051	Gillig	35	Low Floor								1	1	1
166	151	2037	15	2052	Gillig	35	Low Floor									1	1
167	152	2037	15	2052	Gillig	35	Low Floor									1	1
168	153	2037	15	2052	Gillig	35	Low Floor									1	1
169	154	2041	15	2056	Gillig	35	Low Floor										future
170	155	2041	15	2056	Gillig	35	Low Floor										future
171	156	2041	15	2056	Gillig	35	Low Floor										future
172	157	2042	15	2057	Gillig	35	Low Floor										future
173	158	2042	15	2057	Gillig	35	Low Floor										future
Vehicles Replaced								0	0	0	0	0	0	4	3	3	0
Total Vehicles								15	15	15	15	15	15	15	15	15	15
Required Peak								12	12	12	12	12	12	12	12	12	12
Spare Ratio								20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Per Vehicle Cost Diesel						Inflation Factor 2%		$ 597,547	$ 609,498	$ 621,688	$ 634,122	$ 646,804	$ 659,740	$ 672,935	$ 686,394	$ 700,122	$ 714,124
Per Vehicle Cost CNG						CNG Upcharge	$ 48,397	$ 645,944	$ 657,895	$ 670,085	$ 682,519	$ 695,201	$ 708,137	$ 721,332	$ 734,791	$ 748,519	$ 762,521
Note Only: Total Additional for CNG Upcharges								$ -	$ -	$ -	$ -	$ -	$ -	$ 193,588	$ 145,191	$ 145,191	$ -

Capital Improvement Plan - Annual Outlays	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Total Vehicle Replacement Cost Diesel	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,691,740	$ 2,059,182	$ 2,100,366	$ -
Total Vehicle Replacement Cost CNG	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,885,328	$ 2,204,373	$ 2,245,557	$ -
Local Share 20% Diesel	$ -	$ -	$ -	$ -	$ -	$ -	$ 538,348	$ 411,836	$ 420,073	$ -
Non-Local Share Diesel	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,153,392	$ 1,647,346	$ 1,680,293	$ -
Local Share 20% CNG	$ -	$ -	$ -	$ -	$ -	$ -	$ 577,066	$ 440,875	$ 449,111	$ -
Non-Local Share CNG	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,308,262	$ 1,763,498	$ 1,796,446	$ -

APENDIX A-1

Fairbanks North Star Borough: Van Tran - Recommended 10 Year Bus Replacement Plan 2019-2028

Unit	Replaced	Year	LifeCycle	Replace	Make	Length	Model	2019 Due	2020 Due	2021 Due	2022 Due	2023 Due	2024 Due	2025 Due	2026 Due	2027 Due	2028 Due
T144-13	---	2001	7	2008	Ford E450	25	StarTrans	0	Qty 3 - 2019 Cutaways Ordered as Gasoline								
VT143-17	---	2010	7	2017	Ford E450	25	StarTrans	0									
VT142-10	---	2011	7	2018	Ford E350	25	StarTrans	0									
VT2-11	---	2011	7	2018	Ford E350	25	StarTrans	1	0								
VT3-11	---	2011	7	2018	Ford E350	25	StarTrans	1	0								
VT4-11	---	2011	7	2018	Ford E350	25	StarTrans	1	1	0							
VT5-11	---	2011	7	2018	Ford E350	25	StarTrans	1	1	0							
VT6-11	---	2011	7	2018	Ford E350	25	StarTrans	1	1	1	0						
VT7-17	---	2017	7	2024	Ford E350	25	StarTrans	1	1	1	1	1	0				
T15-17	---	2017	7	2024	Ford E450	25	StarTrans	1	1	1	1	1	1	0			
2019-1	T144-13	2019	7	2026	Ford E350	25	StarTrans	1	1	1	1	1	1	1	0		
2019-2	VT143-17	2019	7	2026	Ford E350	25	StarTrans	1	1	1	1	1	1	1	0		
2019-3	VT142-10	2019	7	2026	Ford E350	25	StarTrans	1	1	1	1	1	1	1	0		
2020-1	VT2-11	2020	7	2027	Ford E350	25	StarTrans		1	1	1	1	1	1	1	0	
2020-2	VT3-11	2020	7	2027	Ford E350	25	StarTrans		1	1	1	1	1	1	1	0	
2021-1	VT4-11	2021	7	2028	Ford E350	25	StarTrans			1	1	1	1	1	1	1	0
2021-2	VT5-11	2021	7	2028	Ford E350	25	StarTrans			1	1	1	1	1	1	1	0
2022-1	VT6-11	2022	7	2029	Ford E350	25	StarTrans				1	1	1	1	1	1	1
2024-1	VT7-17	2024	7	2031	Ford E350	25	StarTrans						1	1	1	1	1
2025-1	T15-17	2025	7	2032	Ford E350	25	StarTrans							1	1	1	1
2026-1	2019-1	2026	7	2033	Ford E350	25	StarTrans								1	1	1
2026-2	2019-2	2026	7	2033	Ford E350	25	StarTrans								1	1	1
2026-3	2019-3	2026	7	2033	Ford E350	25	StarTrans								1	1	1
2027-1	2020-1	2027	7	2034	Ford E350	25	StarTrans									1	1
2027-1	2020-2	2027	7	2034	Ford E350	25	StarTrans									1	1
2028-1	2021-1	2028	7	2035	Ford E350	25	StarTrans										1
2028-2	2021-2	2028	7	2035	Ford E350	25	StarTrans										1
VT9-17	---	2017	5	2022	MV1	25	Van	1	1	1	1	1	1	1	1	1	1
Vehicles Replaced								3	2	2	1	0	1	1	3	2	2
Total Vehicles								11	11	11	11	11	11	11	11	11	11
Required Peak								7	7	7	7	7	7	7	7	7	7
Spare Ratio								36%	36%	36%	36%	36%	36%	36%	36%	36%	36%
Per VehicleVehicle Cost Gasoline					Inflation Factor 2%			$ 48,000	$ 48,960	$ 49,939	$ 50,938	$ 51,957	$ 52,996	$ 54,056	$ 55,137	$ 56,240	$ 57,365
Per VehicleVehicle Cost CNG					CNG Upcharge	$22,000		$ 70,000	$ 70,960	$ 71,939	$ 72,938	$ 73,957	$ 74,996	$ 76,056	$ 77,137	$ 78,240	$ 79,365
Note Only: Total Additional for CNG Upcharges								$ 66,000	$ 44,000	$ 44,000	$ 22,000	$ -	$ 22,000	$ 22,000	$ 66,000	$ 44,000	$ 44,000

Capital Improvement Plan - Annual Outlays	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Vehicle Replacement Cost Gasoline	$ 144,000	$ 97,920	$ 99,878	$ 50,938	$ -	$ 52,996	$ 54,056	$ 165,411	$ 112,480	$ 114,730
Total Vehicle Replacement Cost CNG	$ 210,000	$ 141,920	$ 143,878	$ 72,938	$ -	$ 74,996	$ 76,056	$ 231,411	$ 156,480	$ 158,730
Local Share 20% Gasoline	$ 28,800	$ 19,584	$ 19,976	$ 10,188	$ -	$ 10,599	$ 10,811	$ 33,082	$ 22,496	$ 22,946
Non-Local 80% Share Gasonline	$ 115,200	$ 78,336	$ 79,902	$ 40,750	$ -	$ 42,397	$ 43,245	$ 132,329	$ 89,984	$ 91,784
Local Share 20% CNG	$ 42,000	$ 28,384	$ 28,776	$ 14,588	$ -	$ 14,999	$ 15,211	$ 46,282	$ 31,296	$ 31,746
Non-Local Share CNG	$ 168,000	$ 113,536	$ 115,102	$ 58,350	$ -	$ 59,997	$ 60,845	$ 185,129	$ 125,184	$ 126,984

APENDIX A-1

Fairbanks North Star Borough: Van Tran - Recommended 10 Year Bus Replacement Plan 2029-2038

Unit	Replaced	Year	LifeCycle	Replace	Make	Length	Model	2029 Due	2030 Due	2031 Due	2032 Due	2033 Due	2034 Due	2035 Due	2036 Due	2037 Due	2038 Due
2022-1	VT6-11	2022	7	2029	Ford E350	25	StarTrans	0									
2024-1	VT7-17	2024	7	2031	Ford E350	25	StarTrans	1	1	0							
2025-1	T15-17	2025	7	2032	Ford E350	25	StarTrans	1	1	1	0						
2026-1	2019-1	2026	7	2033	Ford E350	25	StarTrans	1	1	1	1	0					
2026-2	2019-2	2026	7	2033	Ford E350	25	StarTrans	1	1	1	1	0					
2026-3	2019-3	2026	7	2033	Ford E350	25	StarTrans	1	1	1	1	0					
2027-1	2020-1	2027	7	2034	Ford E350	25	StarTrans	1	1	1	1	1	0				
2027-1	2020-2	2027	7	2034	Ford E350	25	StarTrans	1	1	1	1	1	0				
2028-1	2021-1	2028	7	2035	Ford E350	25	StarTrans	1	1	1	1	1	1	0			
2028-2	2021-2	2028	7	2035	Ford E350	25	StarTrans	1	1	1	1	1	1	0			
2029-1	2022-1	2029	7	2036	Ford E350	25	StarTrans	1	1	1	1	1	1	1	0		
2031-1	2024-1	2031	7	2038	Ford E350	25	StarTrans			1	1	1	1	1	1	1	0
2032-1	2025-1	2032	7	2039	Ford E350	25	StarTrans				1	1	1	1	1	1	1
2033-1	2026-1	2033	7	2040	Ford E350	25	StarTrans					1	1	1	1	1	1
2033-2	2026-2	2033	7	2040	Ford E350	25	StarTrans					1	1	1	1	1	1
2033-3	2026-3	2033	7	2040	Ford E350	25	StarTrans					1	1	1	1	1	1
2034-1	2027-1	2034	7	2041	Ford E350	25	StarTrans						1	1	1	1	1
2034-2	2027-1	2034	7	2041	Ford E350	25	StarTrans						1	1	1	1	1
2035-1	2028-1	2035	7	2042	Ford E350	25	StarTrans							1	1	1	1
2035-2	2028-2	2035	7	2042	Ford E350	25	StarTrans							1	1	1	1
2036-1	2029-1	2036	7	2043	Ford E350	25	StarTrans								1	1	1
2038-1	2031-1	2038	7	2045	Ford E350	25	StarTrans										1
VT9-17	---	2017	5	2022	MV1	25	Van	1	1	1	1	1	1	1	1	1	1
Vehicles Replaced								1	0	1	1	3	2	2	1	0	1
Total Vehicles								11	11	11	11	11	11	11	11	11	11
Required Peak								7	7	7	7	7	7	7	7	7	7
Spare Ratio								36%	36%	36%	36%	36%	36%	36%	36%	36%	36%
Per Vehicle Cost Gasoline						Inflation Factor 2%		$ 57,365	$ 58,512	$ 59,682	$ 60,876	$ 62,094	$ 63,336	$ 64,603	$ 65,895	$ 67,213	$ 68,557
Per Vehicle Cost CNG						CNG Upcharge	$22,000	$ 79,365	$ 80,512	$ 81,682	$ 82,876	$ 84,094	$ 85,336	$ 86,603	$ 87,895	$ 89,213	$ 90,557
Note Only: Total Additional for CNG Upcharges								$ 22,000	$ -	$ 22,000	$ 22,000	$ 66,000	$ 44,000	$ 44,000	$ 22,000	$ -	$ 22,000

Capital Improvement Plan - Annual Outlays	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Total Vehicle Replacement Cost Gasoline	$ 57,365	$ -	$ 59,682	$ 60,876	$ 186,282	$ 126,672	$ 129,206	$ 65,895	$ -	$ 68,557
Total Vehicle Replacement Cost CNG	$ 79,365	$ -	$ 81,682	$ 82,876	$ 252,282	$ 170,672	$ 173,206	$ 87,895	$ -	$ 90,557
Local Share 20% Gasoline	$ 11,473	$ -	$ 11,936	$ 12,175	$ 37,256	$ 25,334	$ 25,841	$ 13,179	$ -	$ 13,711
Non-Local Share Gasonline	$ 45,892	$ -	$ 47,746	$ 48,701	$ 149,026	$ 101,338	$ 103,365	$ 52,716	$ -	$ 54,846
Local Share 20% CNG	$ 15,873	$ -	$ 16,336	$ 16,575	$ 50,456	$ 34,134	$ 34,641	$ 17,579	$ -	$ 18,111
Non-Local Share CNG	$ 63,492	$ -	$ 65,346	$ 66,301	$ 201,826	$ 136,538	$ 138,565	$ 70,316	$ -	$ 72,446

APPENDIX A-2

Fairbanks North Star Borough; MACS and Van Tran
Fleet Replacement and Fuel Cost Projections

FY In Service	CNG Buses	CNG Upcharge	Diesel Gallons	Cumulative Gallons	* Diesel $/Gal	# NG $/DGE	Spread / Savings	CNG Cutaways	CNG Upcharge	Gasoline Gallons	Cumulative Gallons	* Gasoline $/Gal	# NG $/GGE	Spread / Savings
2020	4	$ 193,588	32,580	32,580	2.95	3.11	(0.16)	2	$ 44,000	5,642	5,642	3.25	2.75	0.50
2021	3	$ 145,191	24,435	57,015	3.01	2.90	0.11	2	$ 44,000	5,642	11,284	3.32	2.55	0.77
2022	3	$ 145,191	24,435	81,450	3.07	2.90	0.17	1	$ 22,000	2,821	14,105	3.39	2.55	0.84
2023		$ -	-	81,450	3.13	2.90	0.23		$ -	-	14,105	3.46	2.55	0.91
2024		$ -	-	81,450	3.19	2.96	0.23	1	$ 22,000	2,821	16,926	3.53	2.61	0.92
2025		$ -	-	81,450	3.25	3.04	0.21	1	$ 22,000	2,821	19,747	3.60	2.68	0.92
2026	3	$ 145,191	24,435	105,885	3.32	3.10	0.22	3	$ 66,000	8,463	28,210	3.67	2.73	0.94
2027	2	$ 96,794	16,290	122,175	3.39	3.13	0.26	2	$ 44,000	-	28,210	3.74	2.75	0.99
2028		$ -	-	122,175	3.46	3.20	0.26	2	$ 44,000	-	28,210	3.81	2.82	0.99
2029		$ -	-	122,175	3.53	3.28	0.25	1	$ 22,000	-	28,210	3.89	2.90	0.99
2030		$ -	-	122,175	3.60	3.33	0.27		$ -	-	28,210	3.97	2.93	1.04
2031		$ -	-	122,175	3.67	3.38	0.29	1	$ 22,000	-	28,210	4.05	2.98	1.07
2032		$ -	-	122,175	3.74	3.38	0.36	1	$ 22,000	-	28,210	4.13	2.98	1.15
2033		$ -	-	122,175	3.81	3.38	0.43	3	$ 66,000	-	28,210	4.21	2.98	1.23
2034		$ -	-	122,175	3.89	3.38	0.51	2	$ 37,714	-	28,210	4.29	2.98	1.31
2035	4	$ 80,662	-	122,175	3.97	3.38	0.59	2	$ 31,429	-	28,210	4.38	2.98	1.40
2036	3	$ 48,397	-	122,175	4.05	3.38	0.67	1	$ 12,571	-	28,210	4.47	2.98	1.49
2037	3	$ 36,298	-	122,175	4.13	3.38	0.75		$ -	-	28,210	4.56	2.98	1.58
2038		$ -	-	122,175	4.21	3.38	0.83	1	$ 6,286	-	28,210	4.65	2.98	1.67
2039		$ -	-	122,175	4.29	3.38	0.91	1	$ 3,143	-	28,210	4.74	2.98	1.76
TOTALS	25	891,311		2,109,555				27	$ 531,143		476,749			

Baseline Diesel: $ 2.950 * Increases 2% Annually

CNG Vehicle Upcharge MACS $ 48,397

Average Annual Diesel Per Vehicle 8,145

CNG DGE 143.94 CF

CNG GGE 126.67 CF

Baseline Gasoline: $ 3.250 * Increases 2.0% Annually

CNG Vehicle Upcharge Van Tran $ 22,000

Average Annual Gas Per Vehicle 2,821

APPENDIX A-3

Fairbanks North Star Borough
MACS Service CNG Fleet
Detailed Project Cash Flow

	A_1	A_2	A	B	C	D = A + B + C	E	F	G	H = E + F + G	I = D + H
Year	[1]Annual Fuel Costs Diesel	[1]Annual Fuel Costs CNG	[1]Annual Fuel Cost Savings	[2]Annual Fleet Maintenance Costs	[2]Annual Facility Maintenance Costs	Total Change In Operational Expenditures	[3]Incremental CNG Fleet Expenditures	[4] Facility CNG Premium Expenditure	[5]Fueling Facility Expenditure	Total Capital Expenditures	Net Annual Cash Flow
0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1	$96,111	$101,324	$5,213	$0	$0	$5,213	$193,588	$0	$0	$193,588	-$198,801
2	$171,615	$165,344	-$6,272	$0	$0	-$6,272	$145,191	$0	$0	$145,191	-$138,919
3	$250,052	$236,205	-$13,847	$0	$0	-$13,847	$145,191	$0	$0	$145,191	-$131,345
4	$254,939	$236,205	-$18,734	$0	$0	-$18,734	$0	$0	$0	$0	$18,734
5	$259,826	$241,092	-$18,734	$0	$0	-$18,734	$0	$0	$0	$0	$18,734
6	$264,713	$247,608	-$17,105	$0	$0	-$17,105	$0	$0	$0	$0	$17,105
7	$351,538	$328,244	-$23,295	$0	$0	-$23,295	$145,191	$0	$0	$145,191	-$121,896
8	$414,173	$382,408	-$31,766	$0	$0	-$31,766	$96,794	$0	$0	$96,794	-$65,029
9	$422,726	$390,960	-$31,766	$0	$0	-$31,766	$0	$0	$0	$0	$31,766
10	$431,278	$400,734	-$30,544	$0	$0	-$30,544	$0	$0	$0	$0	$30,544
11	$439,830	$406,843	-$32,987	$0	$0	-$32,987	$0	$0	$0	$0	$32,987
12	$448,382	$412,952	-$35,431	$0	$0	-$35,431	$0	$0	$0	$0	$35,431
13	$456,935	$412,952	-$43,983	$0	$0	-$43,983	$0	$0	$0	$0	$43,983
14	$465,487	$412,952	-$52,535	$0	$0	-$52,535	$0	$0	$0	$0	$52,535
15	$475,261	$412,952	-$62,309	$0	$0	-$62,309	$0	$0	$0	$0	$62,309
16	$485,035	$412,952	-$72,083	$0	$0	-$72,083	$80,662	$0	$0	$80,662	-$8,578
17	$494,809	$412,952	-$81,857	$0	$0	-$81,857	$48,397	$0	$0	$48,397	$33,460
18	$504,583	$412,952	-$91,631	$0	$0	-$91,631	$36,298	$0	$0	$36,298	$55,334
19	$514,357	$412,952	-$101,405	$0	$0	-$101,405	$0	$0	$0	$0	$101,405
20	$524,131	$412,952	-$111,179	$0	$0	-$111,179	$0	$0	$0	$0	$111,179
Totals	$7,725,777	$6,853,529	-$872,248	$0	$0	-$872,248	$891,311	$0	$0	$891,311	-$19,063

[1] Differential between diesel or gasoline and CNG.

[2] No Additional costs associated with the maintenance of CNG vehicles.

[3] Incremental cost for purchasing CNG buses versus Diesel or Gasoline.

[4] Cost for Building CNG Ready Maintenance, Storage, and Indoor Fueling & Service.

[5] Costs for constructing CNG Fueling Station

Internal Rate of Return: 0.0%

[6] Net Present Value N.A.

[6] Assumes Discount Rate of 2.5%

APPENDIX A-3

Fairbanks North Star Borough
Van Tran Service CNG Fleet
Detailed Project Cash Flow

	A_1	A_2	A	B	C	D = A + B + C	E	F	G	H = E + F + G	I = D + H
Year	[1]Annual Fuel Costs Diesel	[1]Annual Fuel Costs CNG	[1]Annual Fuel Cost Savings	[2]Annual Fleet Maintenance Costs	[2]Annual Facility Maintenance Costs	Total Change In Operational Expenditures	[3]Incremental CNG Fleet Expenditures	[4] Facility Renovation Expenditure	[5]Fueling Facility Expenditure	Total Capital Expenditures	Net Annual Cash Flow
0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1	$18,337	$15,516	-$2,821	$0	$0	-$2,821	$44,000	$0	$0	$44,000	-$41,179
2	$37,463	$28,774	-$8,689	$0	$0	-$8,689	$44,000	$0	$0	$44,000	-$35,311
3	$47,816	$35,968	-$11,848	$0	$0	-$11,848	$22,000	$0	$0	$22,000	-$10,152
4	$48,803	$35,968	-$12,836	$0	$0	-$12,836	$0	$0	$0	$0	$12,836
5	$59,749	$44,177	-$15,572	$0	$0	-$15,572	$22,000	$0	$0	$22,000	-$6,428
6	$71,089	$52,922	-$18,167	$0	$0	-$18,167	$22,000	$0	$0	$22,000	-$3,833
7	$103,531	$77,013	-$26,517	$0	$0	-$26,517	$66,000	$0	$0	$66,000	-$39,483
8	$105,505	$77,578	-$27,928	$0	$0	-$27,928	$44,000	$0	$0	$44,000	-$16,072
9	$107,480	$79,552	-$27,928	$0	$0	-$27,928	$44,000	$0	$0	$44,000	-$16,072
10	$109,737	$81,809	-$27,928	$0	$0	-$27,928	$22,000	$0	$0	$22,000	$5,928
11	$111,994	$82,655	-$29,338	$0	$0	-$29,338	$0	$0	$0	$0	$29,338
12	$114,251	$84,066	-$30,185	$0	$0	-$30,185	$22,000	$0	$0	$22,000	$8,185
13	$116,507	$84,066	-$32,442	$0	$0	-$32,442	$22,000	$0	$0	$22,000	$10,442
14	$118,764	$84,066	-$34,698	$0	$0	-$34,698	$66,000	$0	$0	$66,000	-$31,302
15	$121,021	$84,066	-$36,955	$0	$0	-$36,955	$37,714	$0	$0	$37,714	-$759
16	$123,560	$84,066	-$39,494	$0	$0	-$39,494	$31,429	$0	$0	$31,429	$8,065
17	$126,099	$84,066	-$42,033	$0	$0	-$42,033	$12,571	$0	$0	$12,571	$29,461
18	$128,638	$84,066	-$44,572	$0	$0	-$44,572	$0	$0	$0	$0	$44,572
19	$131,177	$84,066	-$47,111	$0	$0	-$47,111	$6,286	$0	$0	$6,286	$40,825
20	$133,715	$84,066	-$49,650	$0	$0	-$49,650	$3,143	$0	$0	$3,143	$46,507
Totals	$1,935,234	$1,368,524	-$566,711	$0	$0	-$566,711	$531,143	$0	$0	$531,143	$35,568

[1] Differential between diesel or gasoline and CNG.

[2] No Additional costs associated with the maintenance of CNG vehicles.

[3] Incremental cost for purchasing CNG buses versus Diesel or Gasoline.

[4] Cost for Building CNG Ready Maintenance, Storage, and Indoor Fueling & Service.

[5] Costs for constructing CNG Fueling Station

Internal Rate of Return: 0.0%

[6] Net Present Value N.A.

[6] Assumes Discount Rate of 2.5%

APPENDIX A-3

Fairbanks North Star Borough
MACS & Van Tran Service CNG Fleet
Detailed Project Cash Flow - Without Facility and CNG Station Costs

	A_1	A_2	A	B	C	D = A + B + C	E	F	G	H = E + F + G	I = D + H
Year	[1]Annual Fuel Costs Diesel	[1]Annual Fuel Costs CNG	[1]Annual Fuel Cost Savings	[2]Annual Fleet Maintenance Costs	[2]Annual Facility Maintenance Costs	Total Change In Operational Expenditures	[3]Incremental CNG Fleet Expenditures	[4] Facility Renovation Expenditure	[5]Fueling Facility Expenditure	Total Capital Expenditures	Net Annual Cash Flow
0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1	$114,448	$116,839	$2,392	$0	$0	$2,392	$237,588	$0	$0	$237,588	-$239,980
2	$209,078	$194,118	-$14,960	$0	$0	-$14,960	$189,191	$0	$0	$189,191	-$174,231
3	$297,867	$272,173	-$25,695	$0	$0	-$25,695	$167,191	$0	$0	$167,191	-$141,496
4	$303,742	$272,173	-$31,569	$0	$0	-$31,569	$0	$0	$0	$0	$31,569
5	$319,574	$285,269	-$34,305	$0	$0	-$34,305	$22,000	$0	$0	$22,000	$12,305
6	$335,802	$300,530	-$35,272	$0	$0	-$35,272	$22,000	$0	$0	$22,000	$13,272
7	$455,069	$405,257	-$49,812	$0	$0	-$49,812	$211,191	$0	$0	$211,191	-$161,379
8	$519,679	$459,985	-$59,693	$0	$0	-$59,693	$140,794	$0	$0	$140,794	-$81,101
9	$530,206	$470,512	-$59,693	$0	$0	-$59,693	$44,000	$0	$0	$44,000	$15,693
10	$541,015	$482,543	-$58,472	$0	$0	-$58,472	$22,000	$0	$0	$22,000	$36,472
11	$551,824	$489,498	-$62,326	$0	$0	-$62,326	$0	$0	$0	$0	$62,326
12	$562,633	$497,017	-$65,615	$0	$0	-$65,615	$22,000	$0	$0	$22,000	$43,615
13	$573,442	$497,017	-$76,425	$0	$0	-$76,425	$22,000	$0	$0	$22,000	$54,425
14	$584,251	$497,017	-$87,234	$0	$0	-$87,234	$66,000	$0	$0	$66,000	$21,234
15	$596,282	$497,017	-$99,264	$0	$0	-$99,264	$37,714	$0	$0	$37,714	$61,550
16	$608,595	$497,017	-$111,577	$0	$0	-$111,577	$112,090	$0	$0	$112,090	-$513
17	$620,907	$497,017	-$123,890	$0	$0	-$123,890	$60,968	$0	$0	$60,968	$62,922
18	$633,220	$497,017	-$136,203	$0	$0	-$136,203	$36,298	$0	$0	$36,298	$99,905
19	$645,533	$497,017	-$148,516	$0	$0	-$148,516	$6,286	$0	$0	$6,286	$142,230
20	$657,846	$497,017	-$160,829	$0	$0	-$160,829	$3,143	$0	$0	$3,143	$157,686
Totals	$9,661,011	$8,222,052	-$1,438,959	$0	$0	-$1,438,959	$1,422,454	$0	$0	$1,422,454	$16,504

[1] Differential between diesel or gasoline and CNG.

[2] No Additional costs associated with the maintenance of CNG vehicles.

[3] Incremental cost for purchasing CNG buses versus Diesel or Gasoline.

[4] Cost for Building CNG Ready Maintenance, Storage, and Indoor Fueling & Service.

[5] Costs for constructing CNG Fueling Station

Internal Rate of Return: 0.0%

[6] Net Present Value N.A.

[6] Assumes Discount Rate of 2.5%

APPENDIX A-3

Fairbanks North Star Borough
MACS & Van Tran Service CNG Fleet
Detailed Project Cash Flow - All Capital Costs

	A_1	A_2	A	B	C	D = A + B + C	E	F	G	H = E + F + G	I = D + H
Year	[1]Annual Fuel Costs Diesel	[1]Annual Fuel Costs CNG	[1]Annual Fuel Cost Savings	[2]Annual Fleet Maintenance Costs	[2]Annual Facility Maintenance Costs	Total Change In Operational Expenditures	[3]Incremental CNG Fleet Expenditures	[4] Facility Renovation Expenditure	[5]Fueling Facility Expenditure	Total Capital Expenditures	Net Annual Cash Flow
0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1	$114,448	$116,839	$2,392	$0	$0	$2,392	$237,588	$571,655	$2,175,722	$2,984,965	-$2,987,357
2	$209,078	$194,118	-$14,960	$0	$0	-$14,960	$189,191	$0	$0	$189,191	-$174,231
3	$297,867	$272,173	-$25,695	$0	$0	-$25,695	$167,191	$0	$0	$167,191	-$141,496
4	$303,742	$272,173	-$31,569	$0	$0	-$31,569	$0	$0	$0	$0	$31,569
5	$319,574	$285,269	-$34,305	$0	$0	-$34,305	$22,000	$0	$0	$22,000	$12,305
6	$335,802	$300,530	-$35,272	$0	$0	-$35,272	$22,000	$0	$0	$22,000	$13,272
7	$455,069	$405,257	-$49,812	$0	$0	-$49,812	$211,191	$0	$0	$211,191	-$161,379
8	$519,679	$459,985	-$59,693	$0	$0	-$59,693	$140,794	$0	$0	$140,794	-$81,101
9	$530,206	$470,512	-$59,693	$0	$0	-$59,693	$44,000	$0	$0	$44,000	$15,693
10	$541,015	$482,543	-$58,472	$0	$0	-$58,472	$22,000	$0	$0	$22,000	$36,472
11	$551,824	$489,498	-$62,326	$0	$0	-$62,326	$0	$0	$0	$0	$62,326
12	$562,633	$497,017	-$65,615	$0	$0	-$65,615	$22,000	$0	$0	$22,000	$43,615
13	$573,442	$497,017	-$76,425	$0	$0	-$76,425	$22,000	$0	$0	$22,000	$54,425
14	$584,251	$497,017	-$87,234	$0	$0	-$87,234	$66,000	$0	$0	$66,000	$21,234
15	$596,282	$497,017	-$99,264	$0	$0	-$99,264	$37,714	$0	$0	$37,714	$61,550
16	$608,595	$497,017	-$111,577	$0	$0	-$111,577	$112,090	$0	$0	$112,090	-$513
17	$620,907	$497,017	-$123,890	$0	$0	-$123,890	$60,968	$0	$0	$60,968	$62,922
18	$633,220	$497,017	-$136,203	$0	$0	-$136,203	$36,298	$0	$0	$36,298	$99,905
19	$645,533	$497,017	-$148,516	$0	$0	-$148,516	$6,286	$0	$0	$6,286	$142,230
20	$657,846	$497,017	-$160,829	$0	$0	-$160,829	$3,143	$0	$0	$3,143	$157,686
Totals	$9,661,011	$8,222,052	-$1,438,959	$0	$0	-$1,438,959	$1,422,454	$571,655	$2,175,722	$4,169,831	-$2,730,873

[1] Differential between diesel or gasoline and CNG.

[2] No Additional costs associated with the maintenance of CNG vehicles.

[3] Incremental cost for purchasing CNG buses versus Diesel or Gasoline.

[4] Cost for Building CNG Ready Maintenance, Storage, and Indoor Fueling & Service.

[5] Costs for constructing CNG Fueling Station

Internal Rate of Return: 0.0%

[6] Net Present Value N.A.

[6] Assumes Discount Rate of 2.5%

OPINION OF PROBABLE COST WORKSHEET

Project Title:	DA Fairbanks AK Transit Garage	Project No.:	383901
Estimate:	**Fairbanks Operations and Maintenance Facility - Option A**	Revision Date:	08/15/2018
Location:	Fairbanks, AK	Orig. Date:	05/31/2018
Description:	Option A: Entire Repair Facility with CNG Upgrades	Estimated by:	CBC, RB1, SRN
File Name:	CNG Feasibility Study Estimates.xlsx	Checked by:	JTW
		Approved by:	SRN

ITEM NO.	DESCRIPTION	ESTIMATED QUANTITY	UNIT	UNIT PRICE MAT.& LAB.	ESTIMATED AMOUNT
	Option A: Entire Repair Facility with CNG Upgrades				
	Methane Detectors, conduit, wire and prog. (CNG premium only)	28,544	ea	$ 4.40	$ 125,594
	Emergency Exhaust Fan System @ 9,000 cfm	5	ea	$ 9,200	$ 46,000
	Controls	1	ls	$ 18,500	$ 18,500
	Tailpipe Exhaust Reels, Hoses, Controls (CNG Premium only)	10	ea	$ 4,400.00	$ 44,000
			Sub Total		$ 234,094
	Option A: Entire Repair Facility with CNG Upgrades			**Project Sub Total:**	$ 234,094
25.0%	Alaska Escalation				$ 58,524
20.0%	Construction Contingency				$ 46,819
0.0%	Design				$ -
5.0%	Genaral Contractor Fee				$ 11,705
10.0%	General Conditions				$ 23,409
				ADDITIONAL PROJECT CHARGES	$ 140,456
	Fairbanks Operations and Maintenance Facility - Option A			**TOTAL**	**$ 374,550**

OPINION OF PROBABLE COST WORKSHEET

Project Title:	DA Fairbanks AK Transit Garage	Project No.:	383901
Estimate:	**Fairbanks Operations and Maintenance Facility - Option B**	Revision Date:	08/15/2018
Location:	Fairbanks, AK	Orig. Date:	05/31/2018
Description:	Option B: Two Repair Bays with CNG Upgrades	Estimated by:	CBC, RB1, SRN
File Name:	CNG Feasibility Study Estimates.xlsx	Checked by:	JTW
		Approved by:	SRN

ITEM NO.	DESCRIPTION	ESTIMATED QUANTITY	UNIT	UNIT PRICE MAT.& LAB.	ESTIMATED AMOUNT
	Option B: Two Repair Bays with CNG upgrades				
	Methane Detectors, conduit, wire and prog. (CNG premium only)	4,745	sf	$ 4.40	$ 20,878
	Emergency Exhuast Fan System @ 10,000 cfm	1	ea	$ 9,500	$ 9,500
	Controls	1	ls	$ 8,400	$ 8,400
	Tailpipe Exhaust Reels, Hoses, Controls (CNG Premium only)	2	ea	$ 4,400	$ 8,800
	2-HR CMU Enclosure	1	ls	$ 170,000	$ 170,000
	2-HR Coiling Overhead Doors	2	ea	$ 15,000	$ 30,000
			Sub Total		$ 247,578
	Option B: Two Repair Bays with CNG Upgrades			**Project Sub Total:**	$ 247,578
25.0%	Alaska Escalation				$ 61,895
20.0%	Construction Contingency				$ 49,516
0.0%	Design				$ -
5.0%	Genaral Contractor Fee				$ 12,379
10.0%	General Conditions				$ 24,758
				ADDITIONAL PROJECT CHARGES	$ 148,547
	Fairbanks Operations and Maintenance Facility - Option B			**TOTAL**	**$ 396,125**

OPINION OF PROBABLE COST WORKSHEET

Project Title:	DA Fairbanks AK Transit Garage	Project No.:	383901
Estimate:	**Fairbanks Operations and Maintenance Facility - Indoor CNG Fueling**	Revision Date:	08/15/2018
Location:	Fairbanks, AK	Orig. Date:	05/31/2018
Description:	Indoor CNG Fueling	Estimated by:	CBC, RB1, SRN
File Name:	CNG Feasibility Study Estimates.xlsx	Checked by:	JTW
		Approved by:	SRN

ITEM NO.	DESCRIPTION	ESTIMATED QUANTITY	UNIT	UNIT PRICE MAT.& LAB.	ESTIMATED AMOUNT
	Indoor CNG Fueling & Service Lane				
	Methane Detectors, conduit, wire and prog. (CNG premium only)	1,097	sf	$ 4.40	$ 4,827
	Emergency Exhuast Fan System @ 2500 cfm	1	ea	$ 7,800	$ 7,800
	Controls	1	ea	$ 8,800	$ 8,800
	Class 1, Division 2 compliant wiring Method (CNG Premium Only	1,097	sf	$ 15	$ 16,455
	Class 1, Division 2 Compliant Lighting (CNG Premium Only)	6	ea	$ 750	$ 4,500
	Fire Alarm (Flame Detectors)	2	ea	$ 1,500	$ 3,000
	Compartmentalize Fueling Area - 2 Hr CMU End Wall Enclosures	1	ea	$ 30,000	$ 30,000
	Two Hour Rated Coiling Overhead Doors	2	ea	$ 15,000	$ 30,000
			Sub Total		$ 75,382
	Indoor CNG Fueling Costs			**Project Sub Total:**	$ 75,382
25.0%	Alaska Escalation				$ -
20.0%	Construction Contingency				$ 15,076
0.0%	Design				$ -
5.0%	Genaral Contractor Fee				$ -
10.0%	General Conditions				$ 7,538
				ADDITIONAL PROJECT CHARGES	$ 22,614
	Fairbanks Operations and Maintenance Facility - Indoor CNG Fueling			**TOTAL**	**$ 97,996**

OPINION OF PROBABLE COST WORKSHEET

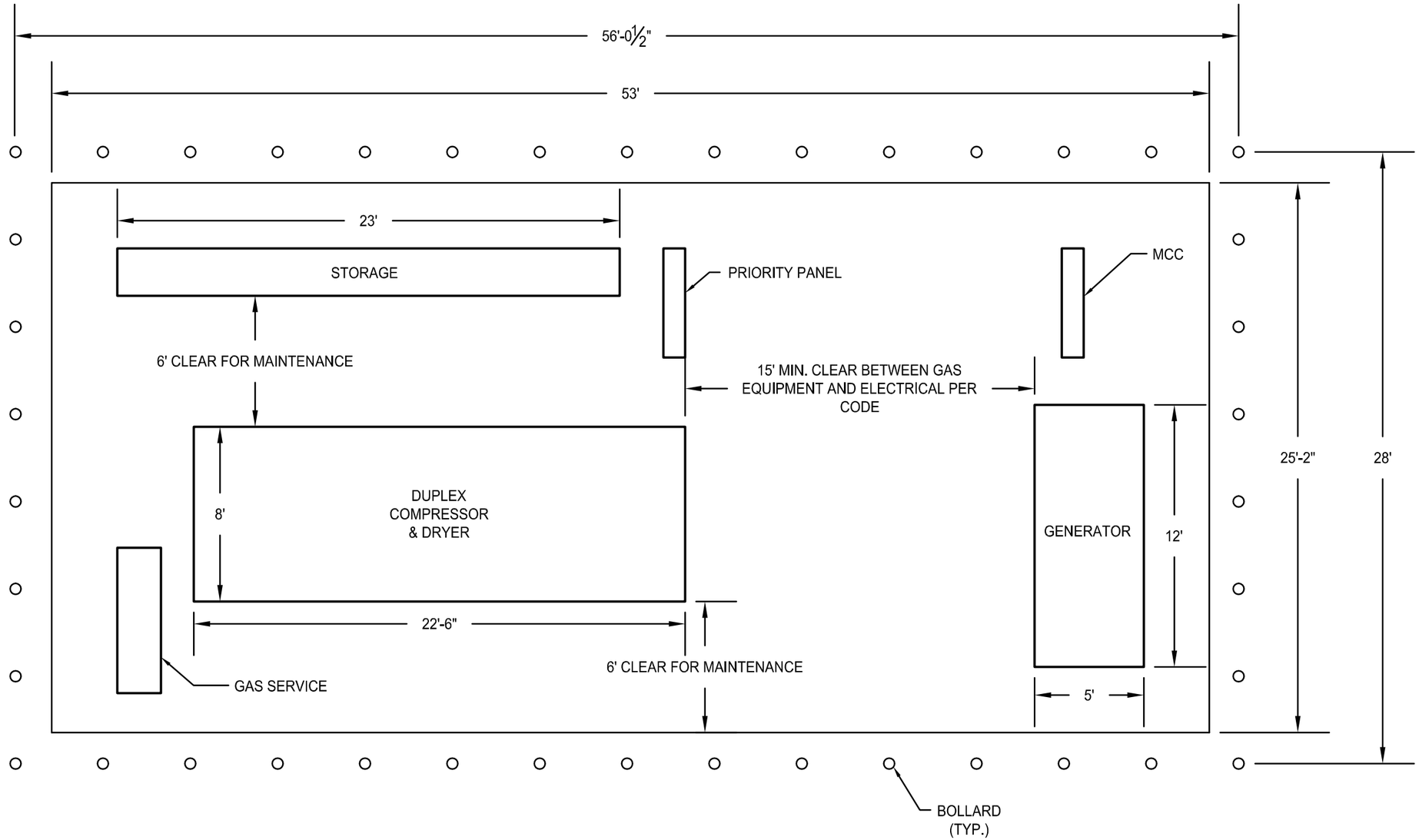
Project Title:	DA Fairbanks AK Transit Garage	Project No.:	383901
Estimate:	**Fairbanks Operations and Maintenance Facility - Storage Detection**	Revision Date:	08/15/2018
Location:	Fairbanks, AK	Orig. Date:	05/31/2018
Description:	Optional Methane Detection for Bus Storage Areas	Estimated by:	CBC, RB1, SRN
File Name:	CNG Feasibility Study Estimates.xlsx	Checked by:	JTW
		Approved by:	SRN

ITEM NO.	DESCRIPTION	ESTIMATED QUANTITY	UNIT	UNIT PRICE MAT.& LAB.	ESTIMATED AMOUNT
	Bus Storage - Optional Methane Detection				
	Methane Detectors, conduit, wire, programming	14,078	sf	$ 4.40	$ 61,943
			Sub Total		$ 61,943
	Optional Methane Detection for Bus Storage Areas			**Project Sub Total:**	$ 61,943
25.0%	Alaska Escalation				$ 15,486
20.0%	Construction Contingency				$ 12,389
0.0%	Design				$ -
5.0%	Genaral Contractor Fee				$ 3,097
10.0%	General Conditions				$ 6,194
				ADDITIONAL PROJECT CHARGES	$ 37,166
	Fairbanks Operations and Maintenance Facility - Storage Detection			**TOTAL**	**$ 99,109**

OPINION OF PROBABLE COST WORKSHEET

Project Title:	DA Fairbanks AK Transit Garage	Project No.:	383901
Estimate:	**CNG FUELING STATION**	Revision Date:	08/15/2018
Location:	Fairbanks, AK	Orig. Date:	05/31/2018
Description:	On Site CNG Station	Estimated by:	CBC, RB1, SRN
File Name:	CNG Feasibility Study Estimates.xlsx	Checked by:	JTW
		Approved by:	SRN

ITEM NO.	DESCRIPTION	ESTIMATED QUANTITY	UNIT	UNIT PRICE MAT.& LAB.	ESTIMATED AMOUNT
	CNG Compressor Compound				
	Natural Gas Service to Compound	1	ea	$ 5,000	$ 5,000
	Duplex 230 SCFM, 100HP NG100 Package	1	ea	$ 400,000	$ 400,000
	Compressor Site Connection Materials	2	ea	$ 1,675	$ 3,350
	Remote Duplex 100 HP Soft Starter Assembly	1	ea	$ 25,000	$ 25,000
	Communication Panel	1	ea	$ 5,850	$ 5,850
	Single Tower Manual Regen Dryer	1	ea	$ 57,500	$ 57,500
	1/2" Priority Panel	1	ea	$ 26,500	$ 26,500
	3 Pack 23' Long ASME storage	1	ea	$ 93,500	$ 93,500
	Dispenser Combination Fleet/High Flow Sequenced	2	ea	$ 59,000	$ 118,000
	Freight From WI - Per Truck	1	ea	$ 19,900	$ 19,900
	Priority panel temperature compensation	1	ea	$ 10,000	$ 10,000
	Bollards - 6" sch 40 galv. Conc. Filled, plastic sleeve	42	ea	$ 800	$ 33,600
	Compound Installation	1	ls	$ 250,000	$ 250,000
	Compound - Contrete Pad and Foundations Allowances	1	ea	$ 75,000	$ 75,000
			Sub Total		$ 1,048,200
	Fueling Systems Electrical				
	Generator (180kW, Natural Gas, Transfer Switch & Control Equi	1	ls	$ 121,650	$ 121,650
	Includes ATS, Weatherproof and Sound (Level 2) Enclosure				
	250A, 480VAC, 3-PH Panelboard (I-Line)	1	ea	$ 2,500	$ 2,500
	Feeder to CNG Compound Service Equipment	150	lf	$ 62.54	$ 9,381
	(3)#3/0AWG & #4GND in 2-1/2" RGS conduit from new building service				
	CNG Equipment Connections	4	ea	$ 8,100	$ 32,400
	Includes Equipment Wiring & Final Connections (90ft run for each)				
	Grounding Loop (Around Compound)	200	lf	$ 3.50	$ 700
	Control Wiring (MCC to each equipment)	4,200	lf	$ 0.77	$ 3,213
	Assume (10) conductors for each equipment in the compound				
	ESD Loop Wiring	150	lf	$ 11.88	$ 1,782
	Fire Alarm System Detection (Flame Detectors)	1	ls	$ 15,000	$ 15,000
			Sub Total		$ 186,626
			Project Sub Total		$ 1,234,826
25.0%	Alaska Escalation				$ 308,707
20.0%	Construction Contingency				$ 246,965
	Design Allowance				$ 200,000
5.0%	Genaral Contractor Fee				$ 61,741
10.0%	General Conditions				$ 123,483
			ADDITIONAL PROJECT CHARGES		$ 940,896
			CNG FUELING STATION TOTAL		**$ 2,175,722**



1 PRELIMINARY CNG COMPOUND LAYOUT

SCALE: NOT TO SCALE

wendel www.wendelcompanies.com	CNG FEASIBILITY STUDY FAIRBANKS, AK	Proj. No. 383901
		Date 05/31/2018
	PRELIMINARY CNG COMPOUND LAYOUT	Ref. Dwg.
		No. M1

APPENDIX A-7

FNSB Transit - 20 Year Projected Natural Gas Demand

Fiscal Year	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Annual MCF	5,404	9,636	13,511	13,511	13,868	14,225	18,814	21,159	21,159	21,159
Monthly MCF	450	803	1,126	1,126	1,156	1,185	1,568	1,763	1,763	1,763
Maximum Annual CF Demand Potential	5,404,237	9,636,083	13,510,593	13,510,593	13,867,929	14,225,265	18,814,448	21,159,230	21,159,230	21,159,230
Total MCF Demand Potential To Date	5,404	15,040	28,551	42,062	55,929	70,155	88,969	110,128	131,288	152,447
MACS Fleet Cumulative CF Demand Projected	4,689,565	8,206,739	11,723,913	11,723,913	11,723,913	11,723,913	15,241,087	17,585,870	17,585,870	17,585,870
Van Tran Fleet Cumulative CF Demand Projected	714,672	1,429,344	1,786,680	1,786,680	2,144,016	2,501,352	3,573,361	3,573,361	3,573,361	3,573,361
MACS Fleet DGE @ 143.94 CF @ 8,145 Annually	4,689,565	3,517,174	3,517,174	-	-	-	3,517,174	2,344,783	-	-
Van Tran Fleet GGE @ 126.67 CF @ 2,821 Annually	714,672	714,672	357,336	-	357,336	357,336	1,072,008	-	-	-
Recommended CNG Fleet Replacement Schedule	**FY20**	**FY21**	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**
35' Low floor CNG buses	4	3	3	-	-	-	3	2	-	-
25' Cutaway CNG buses	2	2	1	-	1	1	3	-	-	-

Fiscal Year	FY30	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39
Annual MCF	21,159	21,159	21,159	21,159	21,159	21,159	21,159	21,159	21,159	21,159
Monthly MCF	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763
Maximum Annual CF Demand Potential	21,159,230	21,159,230	21,159,230	21,159,230	21,159,230	21,159,230	21,159,230	21,159,230	21,159,230	21,159,230
Total MCF Demand Potential To Date	173,606	194,765	215,925	237,084	258,243	279,402	300,561	321,721	342,880	364,039
MACS Fleet Cumulative CF Demand Projected	17,585,870	17,585,870	17,585,870	17,585,870	17,585,870	17,585,870	17,585,870	17,585,870	17,585,870	17,585,870
Van Tran Fleet Cumulative CF Demand Projected	3,573,361 -	3,573,361	3,573,361	3,573,361	3,573,361	3,573,361	3,573,361	3,573,361	3,573,361	3,573,361
MACS Fleet DGE @ 143.94 CF @ 8,145 Annually	-	-	-	-	-	-	-	-	-	-
Van Tran Fleet GGE @ 126.67 CF @ 2,821 Annually	-	-	-	-	-	-	-	-	-	-
Recommended CNG Fleet Replacement Schedule	**FY29**	**FY30**	**FY31**	**FY32**	**FY33**	**FY34**	**FY35**	**FY36**	**FY37**	**FY38**
35' Low floor CNG buses	-	-	-	-	-	-	-	-	-	-
25' Cutaway CNG buses	-	-	-	-	-	-	-	-	-	-

APPENDIX A-8

FNSB TRANSIT FLEET CNG BUS REPLACEMENT EMISSION REDUCTIONS

DIESEL TRANSIT BUSES

Replacement		Unit			Year	BAU "Extended Life" Emissions (tons)				Replacement Life Cycle Emissions (tons)				Net Emission Reductions (tons)			
Cycle	Unit	Replaced	Year	LifeCycle	Replaced	PM2.5	VOC	CO	NOx	PM2.5	VOC	CO	NOx	PM2.5	VOC	CO	NOx
	144	71	2020	15	2035	0.0142	0.066	0.396	2.263	0.0012	0.045	2.668	0.725	0.013	0.021	-2.271	1.538
	145	72	2020	15	2035	0.0164	0.076	0.457	2.609	0.0014	0.051	3.076	0.836	0.015	0.024	-2.619	1.774
	146	73	2020	15	2035	0.0286	0.132	0.796	4.547	0.0024	0.090	5.359	1.456	0.026	0.042	-4.563	3.090
	147	74	2020	15	2035	0.0184	0.085	0.513	2.930	0.0016	0.058	3.453	0.938	0.017	0.027	-2.940	1.991
	148	710	2021	15	2036	0.0142	0.066	0.400	2.262	0.0012	0.045	2.666	0.724	0.013	0.021	-2.266	1.537
	149	75	2021	15	2036	0.0175	0.081	0.493	2.787	0.0015	0.055	3.285	0.893	0.016	0.026	-2.792	1.894
	150	76	2021	15	2036	0.0170	0.079	0.478	2.703	0.0015	0.053	3.187	0.866	0.016	0.025	-2.709	1.837
First	151	77	2022	15	2037	0.0159	0.074	0.451	2.526	0.0014	0.050	2.977	0.809	0.015	0.024	-2.526	1.717
	152	78	2022	15	2037	0.0141	0.066	0.400	2.241	0.0012	0.044	2.642	0.718	0.013	0.021	-2.242	1.523
	153	79	2022	15	2037	0.0150	0.070	0.427	2.392	0.0013	0.047	2.819	0.766	0.014	0.023	-2.392	1.626
	154	141	2026	15	2041	0.0180	0.072	0.384	1.087	0.0019	0.068	4.071	1.106	0.016	0.004	-3.686	-0.019
	155	142	2026	15	2041	0.0172	0.069	0.366	1.036	0.0018	0.065	3.879	1.054	0.015	0.004	-3.513	-0.018
	156	143	2026	15	2041	0.0189	0.076	0.403	1.140	0.0019	0.071	4.268	1.160	0.017	0.005	-3.865	-0.020
	157	Anch1	2027	15	2042	0.0035	0.014	0.077	0.212	0.0004	0.013	0.790	0.215	0.003	0.001	-0.713	-0.002
	158	Anch2	2027	15	2042	0.0143	0.059	0.311	0.860	0.0015	0.054	3.204	0.871	0.013	0.005	-2.893	-0.010
	159	144	2035	15	2050	0.0022	0.059	3.427	0.776	0.0012	0.045	2.668	0.725	0.001	0.014	0.758	0.051
	160	145	2035	15	2050	0.0025	0.068	3.951	0.895	0.0014	0.051	3.076	0.836	0.001	0.016	0.874	0.059
	161	146	2035	15	2050	0.0043	0.118	6.884	1.559	0.0024	0.090	5.360	1.456	0.002	0.029	1.524	0.102
	162	147	2035	15	2050	0.0028	0.076	4.436	1.004	0.0016	0.058	3.454	0.938	0.001	0.019	0.982	0.066
	163	148	2036	15	2051	0.0022	0.059	3.425	0.775	0.0012	0.045	2.667	0.724	0.001	0.014	0.758	0.051
	164	149	2036	15	2051	0.0027	0.073	4.219	0.955	0.0015	0.055	3.285	0.893	0.001	0.018	0.934	0.063
	165	150	2036	15	2051	0.0026	0.070	4.093	0.927	0.0015	0.053	3.187	0.866	0.001	0.017	0.906	0.061
Second	166	151	2037	15	2052	0.0024	0.066	3.824	0.866	0.0012	0.045	2.723	0.751	0.001	0.020	1.101	0.115
	167	152	2037	15	2052	0.0021	0.058	3.394	0.768	0.0011	0.040	2.417	0.667	0.001	0.018	0.977	0.102
	168	153	2037	15	2052	0.0023	0.062	3.621	0.820	0.0012	0.043	2.579	0.711	0.001	0.019	1.043	0.109
	169	154	2041	15	2056	0.0033	0.090	5.229	1.184	0.0010	0.038	2.334	0.711	0.002	0.052	2.895	0.472
	170	155	2041	15	2056	0.0031	0.086	4.982	1.128	0.0010	0.036	2.224	0.678	0.002	0.049	2.758	0.450
	171	156	2041	15	2056	0.0034	0.094	5.483	1.241	0.0011	0.040	2.447	0.746	0.002	0.054	3.035	0.495
	172	157	2042	15	2057	0.0006	0.017	1.014	0.230	0.0002	0.006	0.385	0.123	0.000	0.011	0.629	0.107
	173	158	2042	15	2057	0.0026	0.071	4.115	0.932	0.0007	0.025	1.564	0.498	0.002	0.045	2.551	0.434
DIESEL TOTALS						**0.2822**	**2.152**	**68.448**	**45.656**	**0.0403**	**1.481**	**88.714**	**24.460**	**0.242**	**0.672**	**-20.266**	**21.196**

GASOLINE VAN TRAN BUSES

Replacement		Unit			Year	BAU "Extended Life" Emissions (tons)				Replacement Life Cycle Emissions (tons)				Net Emission Reductions (tons)			
Cycle	Unit	Replaced	Year	LifeCycle	Replaced	PM2.5	VOC	CO	NOx	PM2.5	VOC	CO	NOx	PM2.5	VOC	CO	NOx
	2019-1	T144-13	2019	7	2026	0.0420	0.461	9.502	1.537	0.0005	0.016	1.030	0.378	0.0415	0.445	8.472	1.159
	2019-2	VT143-17	2019	7	2026	0.0071	0.195	2.733	0.192	0.0005	0.016	1.030	0.378	0.0066	0.179	1.703	-0.186
	2019-3	VT142-10	2019	7	2026	0.0070	0.194	2.720	0.192	0.0005	0.016	1.030	0.378	0.0065	0.178	1.690	-0.186
	2020-1	VT2-11	2020	7	2027	0.0070	0.194	2.720	0.192	0.0005	0.016	1.030	0.378	0.0065	0.178	1.690	-0.186
First	2020-2	VT3-11	2020	7	2027	0.0070	0.194	2.720	0.192	0.0005	0.016	1.030	0.378	0.0065	0.178	1.690	-0.186
	2021-1	VT4-11	2021	7	2028	0.0070	0.194	2.720	0.192	0.0005	0.016	1.030	0.378	0.0065	0.178	1.690	-0.186
	2021-2	VT5-11	2021	7	2028	0.0070	0.194	2.720	0.192	0.0005	0.016	1.030	0.378	0.0065	0.178	1.690	-0.186
	2022-1	VT6-11	2022	7	2029	0.0070	0.194	2.720	0.192	0.0005	0.016	1.030	0.378	0.0065	0.178	1.690	-0.186
	2024-1	VT7-17	2024	7	2031	0.0069	0.182	2.690	0.191	0.0005	0.016	1.031	0.378	0.0064	0.166	1.659	-0.187
	2025-1	T15-17	2025	7	2032	0.0069	0.182	2.690	0.191	0.0005	0.016	1.031	0.378	0.0064	0.166	1.659	-0.187
	2026-1	2019-1	2026	7	2033	0.0007	0.033	1.926	0.440	0.0005	0.016	1.031	0.378	0.0002	0.017	0.895	0.062
	2026-2	2019-2	2026	7	2033	0.0007	0.033	1.926	0.440	0.0005	0.016	1.031	0.378	0.0002	0.017	0.895	0.062
	2026-3	2019-3	2026	7	2033	0.0007	0.033	1.926	0.440	0.0005	0.016	1.031	0.378	0.0002	0.017	0.895	0.062
	2027-1	2020-1	2027	7	2034	0.0007	0.033	1.926	0.440	0.0005	0.016	1.031	0.378	0.0002	0.017	0.895	0.062
Second	2027-1	2020-2	2027	7	2034	0.0007	0.033	1.926	0.440	0.0005	0.016	1.031	0.378	0.0002	0.017	0.895	0.062
	2028-1	2021-1	2028	7	2035	0.0007	0.033	1.926	0.440	0.0005	0.016	1.031	0.378	0.0002	0.017	0.895	0.062
	2028-2	2021-2	2028	7	2035	0.0007	0.033	1.926	0.440	0.0005	0.016	1.031	0.378	0.0002	0.017	0.895	0.062
	2029-1	2022-1	2029	7	2036	0.0007	0.033	1.926	0.440	0.0005	0.016	1.031	0.378	0.0002	0.017	0.895	0.062
	2031-1	2024-1	2031	7	2038	0.0007	0.033	1.926	0.440	0.0005	0.016	1.031	0.378	0.0002	0.017	0.895	0.062
	2032-1	2025-1	2032	7	2039	0.0007	0.033	1.926	0.440	0.0005	0.016	1.031	0.378	0.0002	0.017	0.895	0.062
	2033-1	2026-1	2033	7	2040	0.0007	0.033	1.926	0.440	0.0005	0.016	1.031	0.378	0.0002	0.017	0.895	0.062
	2033-2	2026-2	2033	7	2040	0.0007	0.033	1.926	0.440	0.0005	0.016	1.031	0.378	0.0002	0.017	0.895	0.062
	2033-3	2026-3	2033	7	2040	0.0007	0.033	1.926	0.440	0.0005	0.016	1.031	0.378	0.0002	0.017	0.895	0.062
	2034-1	2027-1	2034	7	2041	0.0007	0.033	1.926	0.440	0.0005	0.016	1.031	0.378	0.0002	0.017	0.895	0.062
Third	2034-2	2027-1	2034	7	2041	0.0007	0.033	1.926	0.440	0.0005	0.016	1.031	0.378	0.0002	0.017	0.895	0.062
	2035-1	2028-1	2035	7	2042	0.0007	0.033	1.926	0.440	0.0005	0.016	1.031	0.378	0.0002	0.017	0.895	0.062
	2035-2	2028-2	2035	7	2042	0.0007	0.033	1.926	0.440	0.0005	0.016	1.031	0.378	0.0002	0.017	0.895	0.062
	2036-1	2029-1	2036	7	2043	0.0007	0.033	1.926	0.440	0.0005	0.016	1.031	0.378	0.0002	0.017	0.895	0.062
	2038-1	2031-1	2038	7	2045	0.0007	0.033	1.926	0.440	0.0005	0.016	1.031	0.378	0.0002	0.017	0.895	0.062
	VT9-17	VT9-17	2017	5	2022	0.0061	0.155	1.651	0.160	0.0031	0.110	0.995	0.114	0.0030	0.045	0.656	0.046
GASOLINE TOTALS						**0.1242**	**2.970**	**72.183**	**11.773**	**0.0176**	**0.577**	**30.884**	**11.067**	**0.107**	**2.394**	**41.299**	**0.706**

ENTIRE TRANSIT FLEET TOTALS						**0.4063**	**5.123**	**140.631**	**57.429**	**0.0579**	**2.057**	**119.598**	**35.527**	**0.348**	**3.065**	**21.033**	**21.902**

APPENDIX A-9

Glossary of Abbreviations

ADA	Americans with Disabilities Act
AEO	Annual Energy Outlook
ASME	American Society of Mechanical Engineers
CF	Cubic Feet
CFM	Cubic Feet Per Minute
CH_4	Methane
CNG	Compressed Natural Gas
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DGE	Diesel Gallon Equivalent
DPF	Diesel Particulate Filter
DEF	Diesel Exhaust Fluid
DTH	Dekatherm of Natural Gas
EPA	Environmental Protection Agency
FNSB	Fairbanks North Star Borough
F	Fahrenheit
FNG	Fairbanks Natural Gas
FTA	Federal Transit Administration
GGE	Gasoline Gallon Equivalent
GHGE	Greenhouse Gas Emissions
GPM	Gallons Per Minute
GVEA	Golden Valley Electric Association
G/BHP-HR	Grams Per Brake Horsepower Hour
HP	Horsepower
IFC	International Fire Code
IGU	Interior Gas Utility
IMC	International Mechanical Code
kW	Kilowatt
LNG	Liquefied Natural Gas
MACS	Metropolitan Area Commuter System
MCF	1000 Cubic Feet of Natural Gas
MMBtu	Million British Thermal Units
NEC	National Electrical Code
NFPA	National Fire Protection Association
NG	Natural Gas
NGV	Natural Gas Vehicle
NGVi	Natural Gas Vehicle Institute
NO_2	Nitrogen Dioxide
NOx	Oxides of Nitrogen
NPV	Net Present Value
NZ	Near Zero
PSI	Pounds per Square Inch
QVM	Qualified Vehicle Modifier
SCF	Standard Cubic F
SCFM	Standard Cubic Feet Minute
SCR	Selective Catalytic Reduction
SF	Square Feet
U.S. EIA	US Energy Information Administration
VEFF	Vehicle Equipment Fleet Fund



ARCHITECTURE
ENGINEERING
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CONSTRUCTION MANAGEMENT

401 2nd Avenue North
Suite 206
Minneapolis, MN 55401
612-332-1401

Minnesota
New York
Virginia
Georgia
Arizona
Wisconsin
Connecticut
West Virginia
Washington, DC

By:	Bryce J. Ward, Mayor
Introduced:	01/24/2019
Referred to the Committee of the Whole:	01/24/2019
Advanced:	01/24/2019
Adopted:	02/14/2019

FAIRBANKS NORTH STAR BOROUGH

RESOLUTION NO. 2019–03

A RESOLUTION SUPPORTING CONVERSION FROM DIESEL AND GASOLINE TO COMPRESSED NATURAL GAS (CNG) VEHICLES FOR ALL TRANSIT REVENUE SERVICE VEHICLES WITHIN THE FAIRBANKS NORTH STAR BOROUGH TRANSPORTATION DEPARTMENT

WHEREAS, The CNG feasibility study dated September 6, 2018 is an integral component and requirement of the Federal Transit Administration Bus and Bus Facility Transit Garage Expansion Grant which was appropriated by the FNSB assembly on January 12, 2017; and

WHEREAS, The Transit Garage Expansion Project will include all necessary systems and structure to allow CNG powered vehicles to be stored and maintained within the new facility. The existing Transit Maintenance Center does not contain these provisions; and

WHEREAS, Once fleet conversion is complete, it is estimated that diesel and gasoline fuel consumption will be reduced by 129,315 gallons each year and will instead require 21,159,000 cubic feet of natural gas annually; and

WHEREAS, Converting the transit fleet to CNG provides air quality benefits by reducing particulate matter (PM2.5), volatile organic compounds (VOC), carbon monoxide (CO), nitrogen oxide (NOx) and carbon dioxide (CO2); and

WHEREAS, Committing to a CNG conversion plan could result in additional air quality benefits claimed within the State Implementation Plan for PM2.5 reductions; and

WHEREAS, Initial purchase cost of CNG powered vehicles are higher than those which are powered by liquid fuels. Savings in operational costs over the life of each vehicle are projected to offset the higher initial expense of CNG powered vehicles; and

WHEREAS, Committing to a structured conversion schedule further emphasizes the borough's devotion to encourage and assist borough residents with transitions to natural gas and improved air quality.

NOW THEREFORE BE IT RESOLVED that the Assembly of the Fairbanks North Star Borough recognizes the value and importance to air quality and supports a structured CNG conversion schedule for revenue service vehicles within the transportation department.

PASSED AND APPROVED THIS 14TH DAY OF FEBRUARY, 2019.

Matt Cooper
Presiding Officer

ATTEST:

April Trickey, CMC, Borough Clerk
by Adena Benn, CMC, Deputy Borough Clerk

Yeses: Williams, Sanford, Gray, Lyke, Major, Cooper
Noes: Lojewski, Tacke, Quist

By:	Karl Kassel, Mayor
Introduced:	04/26/2018
Advanced:	04/26/2018
Adopted:	05/14/2018

FAIRBANKS NORTH STAR BOROUGH

ORDINANCE NO. 2017-20-23

AN ORDINANCE AMENDING THE FY 2017-18 BUDGET BY APPROPRIATING $250,251 IN FEDERAL GRANT FUNDS AND $25,634 IN STATE MATCHING FUNDS TO THE TRANSIT ENTERPRISE PROJECTS FUND TO ACQUIRE FOUR NEW PARATRANSIT VANS

WHEREAS, $370,302 of Federal Transit Administration (FTA) funding and $35,735 of State matching funds were appropriated by the Fairbanks North Star Borough (Borough) Assembly in Ordinance No. 2012-20-2F and awarded to the Borough under FTA Grant #AK-95-X012 entitled "12 Congestion Mitigation Air Quality (CMAQ) Van Pool/Ride Share Option" and under Alaska Department of Transportation and Public Facilities (DOT&PF) Agreement #62446 "Van Pool/Ride Share Options Coordinator Project" respectively, and

WHEREAS, The Van Pool/Ride Share Program was unsuccessful and the Borough will lapse federal funds of $250,251, and state matching funds of $25,634 lapses on February 22, 2018; and

WHEREAS, Under Public Law 111-5 and 49 U.S.C. §5307, the FTA makes formula grants available to urbanized areas (cities over 50,000 population) for capital and operating assistance for equipment and facilities owned by operators of public transportation systems; and

WHEREAS, The Americans with Disabilities Act of 1990 (ADA) requires all communities with a fixed bus route system to provide comparable paratransit service for those who cannot use the fixed route service because of their disabilities; and

WHEREAS, The Borough paratransit fleet must replace four vans that have met or exceeded their useful life according to FTA guidelines; and

WHEREAS, The CMAQ Project Evaluation Board approved the transfer of funds from the Van Pool/Ride Share Project to the purchase of four new paratransit vehicles; and

WHEREAS, The Fairbanks Metropolitan Area Transportation System (FMATS) Policy Board approved the transfer of funds from the Van Pool/Ride Share Project to the purchase of four new paratransit vans.

NOW, THEREFORE, BE IT ORDAINED by the Assembly of the Fairbanks North Star Borough:

Section 1. Classification. This ordinance is not of a general and permanent nature and shall not be codified.

Section 2. Lapse of Federal Grant Funds. The federal funds for the Van Pool/Ride Share Program, appropriated in Ordinance No. 2012-20-27, are lapsed.

Section 3. Acceptance of Federal and State Matching Funds. The Borough formally accepts the award of $260,251 in FTA 49 U.S.C. §5307 grant funding and $25,934 in State DOT&PF matching funds.

Section 4. Transit Enterprise Projects Fund Grant Appropriation. The FY 2013-18 budget is hereby amended by appropriating $286,085 to the Transit Enterprise Projects Fund budgetary guideline entitled "FTA §5307 Paratransit Van Purchase" and by increasing estimated revenue from federal grants by $260,251 and estimated revenue from State grants by $25,834.

Section 5. Administrative Fee Waiver. Indirect fees are waived in accordance with Borough Ordinance No. 2011-42, which waived indirect on all existing and future FTA grants and associated matching funds.

Section 6. Eligible Expenditure Period. Expenditures subsequent to the effective date of the executed grant agreement are eligible for reimbursement.

Section 7. Provision for Appropriation Estimates. The appropriation of grant funds is for an estimated amount. The actual amount will be appropriated. Any material difference, as determined by the Chief Financial Officer, will be communicated to the Assembly.

Section 8. Contingency. This appropriation is contingent upon receipt of executed grant agreements with FTA and the DOT&PF.

Section 9. Effective Date. This ordinance shall be effective at 5:00 pm on the first Borough business day following its adoption.

PASSED AND APPROVED THIS 14TH DAY OF JUNE, 2018



Kathryn Dodge
Presiding Officer

ATTEST:

April Trekey, CMC
Borough Clerk

Yeas: Grey, Tacke, Cooper, Roberts, Szarzynski, Quist, Major, Lawrence, Dodge
Nays: None

[illegible]
[illegible]

[illegible]

Template

[illegible]

[illegible]

[illegible]

PURPOSE OF USE	[illegible] Project Costs Previously Approved	[illegible]	Total Project Costs
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]

SOURCE OF FUNDING			
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]

[illegible]

OTHER FUNDING PREVIOUSLY APPROVED FOR THIS PROJECT

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

[illegible]

[illegible]

[illegible]

By	Karl Kasser, Mayor
Introduced	07/27/2017
Advanced	07/27/2017
Adopted	08/07/2017

FAIRBANKS NORTH STAR BOROUGH

ORDINANCE NO. 2017-20-15

AN ORDINANCE AMENDING THE FY 2017-18 BUDGET BY APPROPRIATING $1,742,800 IN FEDERAL AND STATE GRANT FUNDS, AND $97,120 FROM TRANSIT ENTERPRISE FUND UNRESTRICTED NET POSITION TO ACQUIRE FOUR NEW TRANSIT BUSES

WHEREAS, The State of Alaska Department of Transportation and Public Facilities (DOT&PF) has received Federal Highway Administration (FHWA), Congestion Mitigation Air Quality (CMAQ) funding and that funding is expected to be transferred to the Federal Transit Administration (FTA) under 49 U.S.C. Section 5307 as a formula grant for capital and operating assistance for equipment and facilities owned by operators of public transportation systems; and

WHEREAS, The DOT&PF has made available Community Transportation Program (CTP) combined federal and state funding and that funding is expected to be transferred to the FTA under 49 U.S.C. Section 5307 as a formula grant for capital and operating assistance for equipment and facilities owned by operators of public transportation systems; and

WHEREAS, The federal fiscal years 2018-2021 State of Alaska Transportation Improvement Program Amendment 2, approved by the FTA on April 20, 2017, identified funding for bus acquisitions; and

WHEREAS, Two 1994 Fairbanks North Star Borough (Borough) Transit buses have far exceeded their useful life per FTA-required useful service years and five 2007 Borough Transit buses have also exceeded their useful life according to FTA-required useful service lives of 10 years or 350,000 miles; and

WHEREAS, The two 1994 Borough Transit buses' drivetrains are unreliable and require constant repair; and

WHEREAS, An estimated $378,320 in CTP funds are expected to be transferred to FTA and are expected to become available for this project; and

WHEREAS, An estimated $695,920 in FHWA CMAQ funds are expected to be transferred to FTA and are expected to become available for this project; and

WHEREAS, An estimated $80,000 in DOT&PF state match funds are expected to become available; and

WHEREAS, An estimated $67,500 will be provided by Transit Enterprise Fund Unrestricted Net Position as local match;

NOW, THEREFORE, BE IT ORDAINED by the Assembly of the Fairbanks North Star Borough:

Section 1. Classification. This ordinance is not of a general and permanent nature and shall not be codified.

Section 2. Acceptance of CTP Funding. The Borough formally accepts the award of an estimated $179,200 in CTP funding.

Section 3. Acceptance of FY2020 - CMAQ Funding. The Borough formally accepts the award of an estimated $385,500 in CMAQ funding.

Section 4. Acceptance of DOT&PF Match Funding. The Borough formally accepts the award of an estimated $68,250 in DOT&PF match funding.

Section 5. Transit Enterprise Operating Fund Appropriation. Notwithstanding the Reserve Policies section IV.B. of the Borough's fiscal policies as stated in Attachment B of the current year adopted budget Ordinance No. 2017-20, the FY 2017-18 budget is hereby amended by appropriating $67,500 to the Transit Enterprise Operating Fund budgetary guideline entitled "Contributions to Transit Enterprise Projects Fund" and by increasing Contributions from Transit Enterprise Unrestricted Net Position by a like amount.

Section 6. Transit Enterprise Project Fund Appropriation. The FY 2017-18 budget is hereby amended by appropriating $1,809,800 to the Transit Enterprise Project Fund budgetary guideline entitled "Transit Bus Acquisitions" and by increasing estimated revenue from federal and state grants by $1,742,800 and by $67,000 from Transit Enterprise Operating Fund.

Section 7. Provision for Appropriation Estimates. These appropriations are estimated amounts. The actual amounts will be appropriated contingent upon and based upon the adopted grant agreement(s). Any material differences, as determined by the Chief Financial Officer, will be communicated to the Assembly.

Section 8. Provision for Accounting. These appropriations are to be recorded and accounted for on the Borough's books using the most suitable methods, accounts, funds, and budgetary guidelines as determined by the Chief Financial Officer.

Section 9. Eligible Expenditure Period. Expenditures subsequent to the effective date(s) of the executed grant agreement(s) are eligible for reimbursement.

Section 10. Administrative Fee Waiver. Indirect fees are waived in accordance with Borough Ordinance No. 2015-42, which waives indirect fees for planning and Action-EIA grants and associated matching funds.

Section 11. Contingency. This appropriation is contingent upon receipt of the signed grant agreements.

Section 12. Lapse of Funds. Upon the completion or abandonment of the project, any encumbrances unexpended local funds will lapse to the Transit Enterprise Unrestricted Net Position.

Section 13. Effective Date. This ordinance shall be effective at 5:00 p.m. on the first borough business day following its adoption.

PASSED AND APPROVED THIS 10TH DAY OF AUGUST, 2017

Kathryn Dodge
Presiding Officer

SEAL

ATTEST:

Nanci Ashford-Brighton, MMC
Borough Clerk

Yeses: Tackett, Gsodon, Quist, Roberts, Smiley, Gray, Dawson, Lawrence, Dodge
Noes: None

A RESOLUTION OF THE ASSEMBLY OF THE FAIRBANKS NORTH STAR BOROUGH
FISCAL NOTE

I Request

Ordinance No 2017-20 LE Date Introduced July 27, 2017

Abbreviated Title $1,742,900 in Federal and State Grant Funds and $97,100 from the Transit Enterprise Fund to acquire four new transit buses

II Financial Detail

Department/Division Affected Transportation/Transit

EXPENDITURE	Transit Enterprise Operating Fund FY 17/18	Transit Enterprise Projects Fund FY 17/18	Total FY 17/18
Contractual Services			
Capital Outlay			
Contribution to Transit Enterprise Projects Fund	97,100		
Other - Awarding Budget		1,839,900	
Total	97,100	1,839,900	

SOURCE OF FUNDING			
General Fund			
Federal and State Grants		1,742,900	
Contribution From Unrestricted Net Position	97,100		
Contribution From Transit Enterprise Operating Fund		97,100	
Total	97,100	1,839,900	

Specify Funding Sources Federal Highway Administration (FHWA) Congestion Mitigation Air Quality (CMAQ) Program, State of Alaska, Department of Transportation & Public Facilities (DOT&PF), Transit Enterprise Fund Unrestricted Net Position

III. Project Purpose

To acquire four new transit buses

IV Analysis of Future Liabilities and Funding Sources

Ongoing maintenance and operating costs

V Fiscal Certification I certify that funding sources are available as detailed in II above

Deborah R. Brady
Chief Financial Officer

Date

By:	Bryce J. Ward, Mayor
Introduced:	01/24/2019
Referred to the Committee of the Whole:	01/24/2019
Advanced:	01/24/2019
Adopted:	02/14/2019

FAIRBANKS NORTH STAR BOROUGH

RESOLUTION NO. 2019–03

A RESOLUTION SUPPORTING CONVERSION FROM DIESEL AND GASOLINE TO COMPRESSED NATURAL GAS (CNG) VEHICLES FOR ALL TRANSIT REVENUE SERVICE VEHICLES WITHIN THE FAIRBANKS NORTH STAR BOROUGH TRANSPORTATION DEPARTMENT

WHEREAS, The CNG feasibility study dated September 6, 2018 is an integral component and requirement of the Federal Transit Administration Bus and Bus Facility Transit Garage Expansion Grant which was appropriated by the FNSB assembly on January 12, 2017; and

WHEREAS, The Transit Garage Expansion Project will include all necessary systems and structure to allow CNG powered vehicles to be stored and maintained within the new facility. The existing Transit Maintenance Center does not contain these provisions; and

WHEREAS, Once fleet conversion is complete, it is estimated that diesel and gasoline fuel consumption will be reduced by 129,315 gallons each year and will instead require 21,159,000 cubic feet of natural gas annually; and

WHEREAS, Converting the transit fleet to CNG provides air quality benefits by reducing particulate matter (PM2.5), volatile organic compounds (VOC), carbon monoxide (CO), nitrogen oxide (NOx) and carbon dioxide (CO2); and

WHEREAS, Committing to a CNG conversion plan could result in additional air quality benefits claimed within the State Implementation Plan for PM2.5 reductions; and

WHEREAS, Initial purchase cost of CNG powered vehicles are higher than those which are powered by liquid fuels. Savings in operational costs over the life of each vehicle are projected to offset the higher initial expense of CNG powered vehicles; and

WHEREAS, Committing to a structured conversion schedule further emphasizes the borough's devotion to encourage and assist borough residents with transitions to natural gas and improved air quality.

NOW THEREFORE BE IT RESOLVED that the Assembly of the Fairbanks North Star Borough recognizes the value and importance to air quality and supports a structured CNG conversion schedule for revenue service vehicles within the transportation department.

PASSED AND APPROVED THIS 14TH DAY OF FEBRUARY, 2019.

Matt Cooper
Presiding Officer

ATTEST:

April Trickey, CMC, Borough Clerk
by Adena Benn, CMC, Deputy Borough Clerk

Yeses: Williams, Sanford, Gray, Lyke, Major, Cooper
Noes: Lojewski, Tacke, Quist

By:	Karl Kassel, Mayor
Introduced:	04/26/2018
Advanced:	04/26/2018
Adopted:	05/14/2018

FAIRBANKS NORTH STAR BOROUGH

ORDINANCE NO. 2017-20-23

AN ORDINANCE AMENDING THE FY 2017-18 BUDGET BY APPROPRIATING $250,251 IN FEDERAL GRANT FUNDS AND $25,634 IN STATE MATCHING FUNDS TO THE TRANSIT ENTERPRISE PROJECTS FUND TO ACQUIRE FOUR NEW PARATRANSIT VANS

WHEREAS, $370,302 of Federal Transit Administration (FTA) funding and $35,735 of State matching funds were appropriated by the Fairbanks North Star Borough (Borough) Assembly in Ordinance No. 2012-20-2F and awarded to the Borough under FTA Grant #AK-95-X012 entitled "12 Congestion Mitigation Air Quality (CMAQ) Van Pool/Ride Share Option" and under Alaska Department of Transportation and Public Facilities (DOT&PF) Agreement #62446 "Van Pool/Ride Share Options Coordinator Project" respectively, and

WHEREAS, The Van Pool/Ride Share Program was unsuccessful and the Borough will lapse federal funds of $250,251, and state matching funds of $25,634 lapses on February 22, 2018; and

WHEREAS, Under Public Law 111-5 and 49 U.S.C. §5307, the FTA makes formula grants available to urbanized areas (cities over 50,000 population) for capital and operating assistance for equipment and facilities owned by operators of public transportation systems; and

WHEREAS, The Americans with Disabilities Act of 1990 (ADA) requires all communities with a fixed bus route system to provide comparable paratransit service for those who cannot use the fixed route service because of their disabilities; and

WHEREAS, The Borough paratransit fleet must replace four vans that have met or exceeded their useful life according to FTA guidelines; and

WHEREAS, The CMAQ Project Evaluation Board approved the transfer of funds from the Van Pool/Ride Share Project to the purchase of four new paratransit vehicles; and

WHEREAS, The Fairbanks Metropolitan Area Transportation System (FMATS) Policy Board approved the transfer of funds from the Van Pool/Ride Share Project to the purchase of four new paratransit vans.

NOW, THEREFORE, BE IT ORDAINED by the Assembly of the Fairbanks North Star Borough:

Section 1. Classification. This ordinance is not of a general and permanent nature and shall not be codified.

Section 2. Lapse of Federal Grant Funds. The federal funds for the Van Pool/Ride Share Program, appropriated in Ordinance No. 2012-20-27, are lapsed.

Section 3. Acceptance of Federal and State Matching Funds. The Borough formally accepts the award of $260,251 in FTA 49 U.S.C. §5307 grant funding and $25,934 in State DOT&PF matching funds.

Section 4. Transit Enterprise Projects Fund Grant Appropriation. The FY 2013-18 budget is hereby amended by appropriating $286,085 to the Transit Enterprise Projects Fund budgetary guideline entitled "FTA §5307 Paratransit Van Purchase" and by increasing estimated revenue from federal grants by $260,251 and estimated revenue from State grants by $25,834.

Section 5. Administrative Fee Waiver. Indirect fees are waived in accordance with Borough Ordinance No. 2011-42, which waived indirect on all existing and future FTA grants and associated matching funds.

Section 6. Eligible Expenditure Period. Expenditures subsequent to the effective date of the executed grant agreement are eligible for reimbursement.

Section 7. Provision for Appropriation Estimates. The appropriation of grant funds is for an estimated amount. The actual amount will be appropriated. Any material difference, as determined by the Chief Financial Officer, will be communicated to the Assembly.

Section 8. Contingency. This appropriation is contingent upon receipt of executed grant agreements with FTA and the DOT&PF.

Section 9. Effective Date. This ordinance shall be effective at 5:00 pm on the first Borough business day following its adoption.

PASSED AND APPROVED THIS 14TH DAY OF JUNE, 2018



Kathryn Dodge
Presiding Officer

ATTEST:

April Trekey, CMC
Borough Clerk

Yeas: Grey, Tacke, Cooper, Roberts, Szarzynski, Quist, Major, Lawrence, Dodge
Nays: None

[illegible]
[illegible]

[illegible]

Template

[illegible]

[illegible]

[illegible]

PURPOSE OF USE	[illegible] Project Costs Previously Approved	[illegible]	Total Project Costs
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]

SOURCE OF FUNDING			
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]

[illegible]

OTHER FUNDING PREVIOUSLY APPROVED FOR THIS PROJECT

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

[illegible]

[illegible]

[illegible]

By	Karl Kasser, Mayor
Introduced	07/27/2017
Advanced	07/27/2017
Adopted	08/07/2017

FAIRBANKS NORTH STAR BOROUGH

ORDINANCE NO. 2017-20-15

AN ORDINANCE AMENDING THE FY 2017-18 BUDGET BY APPROPRIATING $1,742,800 IN FEDERAL AND STATE GRANT FUNDS, AND $97,120 FROM TRANSIT ENTERPRISE FUND UNRESTRICTED NET POSITION TO ACQUIRE FOUR NEW TRANSIT BUSES

WHEREAS, The State of Alaska Department of Transportation and Public Facilities (DOT&PF) has received Federal Highway Administration (FHWA), Congestion Mitigation Air Quality (CMAQ) funding and that funding is expected to be transferred to the Federal Transit Administration (FTA) under 49 U.S.C. Section 5307 as a formula grant for capital and operating assistance for equipment and facilities owned by operators of public transportation systems; and

WHEREAS, The DOT&PF has made available Community Transportation Program (CTP) combined federal and state funding and that funding is expected to be transferred to the FTA under 49 U.S.C. Section 5307 as a formula grant for capital and operating assistance for equipment and facilities owned by operators of public transportation systems; and

WHEREAS, The federal fiscal years 2018-2021 State of Alaska Transportation Improvement Program Amendment 2, approved by the FTA on April 20, 2017, identified funding for bus acquisitions; and

WHEREAS, Two 1994 Fairbanks North Star Borough (Borough) Transit buses have far exceeded their useful life per FTA-required useful service years and five 2007 Borough Transit buses have also exceeded their useful life according to FTA-required useful service lives of 10 years or 350,000 miles; and

WHEREAS, The two 1994 Borough Transit buses' drivetrains are unreliable and require constant repair; and

WHEREAS, An estimated $378,320 in CTP funds are expected to be transferred to FTA and are expected to become available for this project; and

WHEREAS, An estimated $695,920 in FHWA CMAQ funds are expected to be transferred to FTA and are expected to become available for this project; and

WHEREAS, An estimated $80,000 in DOT&PF state match funds are expected to become available; and

WHEREAS, An estimated $67,500 will be provided by Transit Enterprise Fund Unrestricted Net Position as local match;

NOW, THEREFORE, BE IT ORDAINED by the Assembly of the Fairbanks North Star Borough:

Section 1. Classification. This ordinance is not of a general and permanent nature and shall not be codified.

Section 2. Acceptance of CTP Funding. The Borough formally accepts the award of an estimated $179,200 in CTP funding.

Section 3. Acceptance of FY2020 - CMAQ Funding. The Borough formally accepts the award of an estimated $385,500 in CMAQ funding.

Section 4. Acceptance of DOT&PF Match Funding. The Borough formally accepts the award of an estimated $68,250 in DOT&PF match funding.

Section 5. Transit Enterprise Operating Fund Appropriation. Notwithstanding the Reserve Policies section IV.B. of the Borough's fiscal policies as stated in Attachment B of the current year adopted budget Ordinance No. 2017-20, the FY 2017-18 budget is hereby amended by appropriating $67,500 to the Transit Enterprise Operating Fund budgetary guideline entitled "Contributions to Transit Enterprise Projects Fund" and by increasing Contributions from Transit Enterprise Unrestricted Net Position by a like amount.

Section 6. Transit Enterprise Project Fund Appropriation. The FY 2017-18 budget is hereby amended by appropriating $1,809,800 to the Transit Enterprise Project Fund budgetary guideline entitled "Transit Bus Acquisitions" and by increasing estimated revenue from federal and state grants by $1,742,800 and by $67,000 from Transit Enterprise Operating Fund.

Section 7. Provision for Appropriation Estimates. These appropriations are estimated amounts. The actual amounts will be appropriated contingent upon and based upon the adopted grant agreement(s). Any material differences, as determined by the Chief Financial Officer, will be communicated to the Assembly.

Section 8. Provision for Accounting. These appropriations are to be recorded and accounted for on the Borough's books using the most suitable methods, accounts, funds, and budgetary guidelines as determined by the Chief Financial Officer.

Section 9. Eligible Expenditure Period. Expenditures subsequent to the effective date(s) of the executed grant agreement(s) are eligible for reimbursement.

Section 10. Administrative Fee Waiver. Indirect fees are waived in accordance with Borough Ordinance No. 2015-42, which waives indirect fees for planning and Action-EIA grants and associated matching funds.

Section 11. Contingency. This appropriation is contingent upon receipt of the signed grant agreements.

Section 12. Lapse of Funds. Upon the completion or abandonment of the project, any encumbrances unexpended local funds will lapse to the Transit Enterprise Unrestricted Net Position.

Section 13. Effective Date. This ordinance shall be effective at 5:00 p.m. on the first borough business day following its adoption.

PASSED AND APPROVED THIS 10TH DAY OF AUGUST, 2017

Kathryn Dodge
Presiding Officer

SEAL

ATTEST:

Nanci Ashford-Brighton, MMC
Borough Clerk

Yeses: Tackett, Gsodon, Quist, Roberts, Smiley, Gray, Dawson, Lawrence, Dodge
Noes: None

A RESOLUTION OF THE ASSEMBLY OF THE FAIRBANKS NORTH STAR BOROUGH
FISCAL NOTE

I Request

Ordinance No 2017-20 LE Date Introduced July 27, 2017

Abbreviated Title $1,742,900 in Federal and State Grant Funds and $97,100 from the Transit Enterprise Fund to acquire four new transit buses

II Financial Detail

Department/Division Affected Transportation/Transit

EXPENDITURE	Transit Enterprise Operating Fund FY 17/18	Transit Enterprise Projects Fund FY 17/18	Total FY 17/18
Contractual Services			
Capital Outlay			
Contribution to Transit Enterprise Projects Fund	97,100		
Other - Awarding Budget		1,839,900	
Total	97,100	1,839,900	

SOURCE OF FUNDING			
General Fund			
Federal and State Grants		1,742,900	
Contribution From Unrestricted Net Position	97,100		
Contribution From Transit Enterprise Operating Fund		97,100	
Total	97,100	1,839,900	

Specify Funding Sources Federal Highway Administration (FHWA) Congestion Mitigation Air Quality (CMAQ) Program, State of Alaska, Department of Transportation & Public Facilities (DOT&PF), Transit Enterprise Fund Unrestricted Net Position

III. Project Purpose

To acquire four new transit buses

IV Analysis of Future Liabilities and Funding Sources

Ongoing maintenance and operating costs

V Fiscal Certification I certify that funding sources are available as detailed in II above

Deborah R. Brady
Chief Financial Officer

Date

BACT Determination for Point Sources

Fort Wainwright US Army Garrison and Doyon Utilities BACT Documents

University of Alaska Fairbanks (UAF) BACT Determination BACT Documents

Golden Valley Electric Technology Determination (GVEA) Zehnder Facility BACT Documents

Golden Valley Electric Technology Determination (GVEA) – North Pole Plant BACT Documents

Aurora Chena Aurora BACT Documents

Fort Wainwright US Army Garrison and Doyon Utilities BACT Documents

- DEC Best Available Control Technology Determination for Fort Wainwright US Army Garrison and Doyon Utilities
- DEC letter to Mr. Morris (Fort Wainwright) for the Request for Additional Information on BACT Memorandum by December 22, 2017 (dated October 20, 2017)
- DEC Request for Additional Information Fort Wainwright –Doyon Utilities for HydroGeologic, Inc. Report, June 2017 (on October 20, 2017)
- DEC letter to Mr. Dick (Fort Wainwright) on Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units) (dated April 24, 2015)
- DEC letter to Ms. Hook (Fort Wainwright) on Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units) (on April 24, 2015)
- DEC letter to Mr. Morris (Fort Wainwright) for the Request for Additional Information for the BACT Memorandum for Fort Wainwright by November 1, 2018 (dated September 13, 2018)
- DEC request for Additional Information for BACT Analysis Review HydroGeologic, Inc. Report, June 2017. (dated September 10, 2018)
- Doyon Utilities comments addressing DEC Preliminary BACT for Fort Wainwright (May 23, 2018)
- EPA comments on DEC's Preliminary Draft Serious SIP Development for the Fairbanks nonattainment area
- DEC email to Fort Wainwright with all the attached documents on the request for additional information for BACT technical memorandum (on September 13, 2018)
- United States Army Garrison Alaska (Fort Wainwright) meeting with EPA on March 21, 2019
- United States Army Garrison Alaska (Fort Wainwright) Power Point Presentation (March 21-22, 2019)

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
Air Permits Program

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION
for
Fort Wainwright
US Army Garrison and Doyon Utilities

Prepared by: Aaron Simpson
Supervisor: James R. Plosay
Preliminary Date: May 14, 2019

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Abbreviations/Acronyms

AAC .....Alaska Administrative Code
AAAQS .....Alaska Ambient Air Quality Standards
Department .....Alaska Department of Environmental Conservation
BACT .....Best Available Control Technology
CFB……Circulating Fluidized Bed
CFR. .....Code of Federal Regulations
Cyclones…….Mechanical Separators
DFP……Diesel Particulate Filter
DLN.....Dry Low NOx
DOC……..Diesel Oxidation Catalyst
EPA .....Environmental Protection Agency
ESP…….Electrostatic Precipitator
EU.....Emission Unit
FITR……..Fuel Injection Timing Retard
GCPs……..Good Combustion Practices
HAP.....Hazardous Air Pollutant
ITR…….Ignition Timing Retard
LEA……Low Excess Air
LNB……Low NOx Burners
MR&Rs .....Monitoring, Recording, and Reporting
NESHAPS .....National Emission Standards for Hazardous Air Pollutants
NSCR…….Non-Selective Catalytic Reduction
NSPS .....New Source Performance Standards
ORL.....Owner Requested Limit
PSD.....Prevention of Significant Deterioration
PTE.....Potential to Emit
RICE, ICE .....Reciprocating Internal Combustion Engine, Internal Combustion Engine
SCR .....Selective Catalytic Reduction
SIP .....Alaska State Implementation Plan
SNCR…….Selective Non-Catalytic Reduction
ULSD .....Ultra Low Sulfur Diesel

Units and Measures

gal/hr.....gallons per hour
g/kWh .....grams per kilowatt hour
g/hp-hr .....grams per horsepower hour
hr/day.....hours per day
hr/yr .....hours per year
hp.....horsepower
lb/hr .....pounds per hour
lb/MMBtu.....pounds per million British thermal units
lb/1000 gal.....pounds per 1,000 gallons
kW .....kilowatts
MMBtu/hr.....million British thermal units per hour
MMscf/hr.....million standard cubic feet per hour
ppmv.....parts per million by volume
tpy.....tons per year

Pollutants

CO .....Carbon Monoxide
HAP.....Hazardous Air Pollutant
NOx .....Oxides of Nitrogen
SO_2 .....Sulfur Dioxide
PM-2.5.....Particulate Matter with an aerodynamic diameter not exceeding 2.5 microns
PM-10.....Particulate Matter with an aerodynamic diameter not exceeding 10 microns

1. INTRODUCTION

Fort Wainwright is a military installation located within and adjacent to the city of Fairbanks, Alaska, in the Tanana River Valley. The EUs located within the military installation at Fort Wainwright are either owned and operated by a private utility company, Doyon Utilities, LLC. (DU), or by U.S. Army Garrison Fort Wainwright (FWA). The two entities, DU and FWA, comprise a single stationary source operating under two permits.

In a letter dated April 24, 2015, the Alaska Department of Environmental Conservation (Department) requested the stationary sources expected to be major stationary sources in the particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers (PM-2.5) serious nonattainment area perform a voluntary Best Available Control Technology (BACT) review in support of the state agency's required SIP submittal once the nonattainment area is re-classified as a Serious PM-2.5 nonattainment area. The designation of the area as "Serious" with regard to nonattainment of the 2006 24-hour PM-2.5 ambient air quality standards was published in Federal Register Vol. 82, No. 89, May 10, 2017, pages 21703-21706, with an effective date of June 9, 2017.[1]

This report addresses the significant EUs listed in the DU permit AQ1121TVP02, Revision 2 and the FWA permit AQ0236TVP03, Revision 2. This report provides the Department's review of the BACT analysis for PM-2.5 and BACT analyses provided for oxides of nitrogen (NOx) and sulfur dioxide (SO_2) emissions, which are precursor pollutants that can form PM-2.5 in the atmosphere post combustion.

The following sections review Fort Wainwright's BACT analysis for technical accuracy and adherence to accepted engineering cost estimation practices.

2. BACT EVALUATION

A BACT analysis is an evaluation of all technically available control technologies for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts. 40 CFR 52.21(b)(12) defines BACT as a site-specific determination on a case-by-case basis. The Department's goal is to identify BACT for the permanent emission units (EUs) at Fort Wainwright that emit NOx, PM-2.5, and SO_2, establish emission limits which represent BACT, and assess the level of monitoring, recordkeeping, and reporting (MR&R) necessary to ensure Fort Wainwright applies BACT for the EUs. The Department based the BACT review on the five-step top-down approach set forth in Federal Register Volume 61, Number 142, July 23, 1996 (Environmental Protection Agency). Table A and Table B present the EUs subject to BACT review.

[1] [1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)

Table A: Privatized Emission Units Subject to BACT Review

EU ID[1]	Description of EU	Rating/Size	Location
1	Coal-Fired Boiler 3	230 MMBtu/hr	Central Heating and Power Plant (CHPP)
2	Coal-Fired Boiler 4	230 MMBtu/hr	CHPP
3	Coal-Fired Boiler 5	230 MMBtu/hr	CHPP
4	Coal-Fired Boiler 6	230 MMBtu/hr	CHPP
5	Coal-Fired Boiler 7	230 MMBtu/hr	CHPP
6	Coal-Fired Boiler 8	230 MMBtu/hr	CHPP
7a	South Coal Handling Dust Collector DC-01	13,150 acfm	CHPP
7b	South Underbunker Dust Collector DC-02	884 acfm	CHPP
7c	North Coal Handling Dust Collector NDC-1	9,250 acfm	CHPP
8	Backup Generator Engine	2,937 hp	CHPP
9	Emergency Generator Engine	353 hp	Building 1032
10	Emergency Generator Engine	762 hp	Building 1060
11	Emergency Generator Engine	762 hp	Building 1060
12	Emergency Generator Engine	82 hp	Building 1193
13	Emergency Generator Engine	587 hp	Building 1555
14	Emergency Generator Engine	320 hp	Building 1563
15	Emergency Generator Engine	1,059 hp	Building 2117
16	Emergency Generator Engine	212 hp	Building 2117
17	Emergency Generator Engine	176 hp	Building 2088
18	Emergency Generator Engine	212 hp	Building 2296
19	Emergency Generator Engine	71 hp	Building 3004
20	Emergency Generator Engine	35 hp	Building 3028
21	Emergency Generator Engine	95 hp	Building 3407
22	Emergency Generator Engine	35 hp	Building 3565
23	Emergency Generator Engine	155 hp	Building 3587
24	Emergency Generator Engine	50 hp	Building 3703
25	Emergency Generator Engine	18 hp	Building 5108
26	Emergency Generator	68 hp	Building 1620
27	Emergency Generator	274 hp	Building 1054
28	Emergency Generator	274 hp	Building 4390
29	Emergency Pump Engine	75 hp	Building 1056
30	Emergency Pump Engine	75 hp	Building 3403
31	Emergency Pump Engine	75 hp	Building 3724
32	Emergency Pump Engine	75 hp	Building 4162
33	Emergency Pump Engine	75 hp	Building 1002
34	Emergency Pump Engine	220 hp	Building 3405
35	Emergency Pump Engine	55 hp	Building 4023
36	Emergency Pump Engine	220 hp	Building 3563
51a	DC-1 Fly Ash Dust Collector	3,620 acfm	CHPP
51b	DC-2 Bottom Ash Dust Collector	3,620 acfm	CHPP
52	Coal Storage Pile	N/A	CHPP

Table B: Fort Wainwright Army Emission Units Subject to BACT Review

EU ID[1]	Description of EU	Rating/Size	Location
8	Backup Diesel-Fired Boiler 1	19 MMBtu/hr	Basset Hospital
9	Backup Diesel-Fired Boiler 2	19 MMBtu/hr	Basset Hospital
10	Backup Diesel-Fired Boiler 3	19 MMBtu/hr	Basset Hospital
11	Backup Diesel-Electric Generator 1	900 kW	Basset Hospital
12	Backup Diesel-Electric Generator 2	900 kW	Basset Hospital
13	Backup Diesel-Electric Generator 3	900 kW	Basset Hospital
22	VOC Extraction and Combustion	N/A	
23	Fort Wainwright Landfill	1.97 million cubic meters	
24	Aerospace Activities	N/A	
26	Emergency Generator	324 hp	Building 2132
27	Emergency Generator	67 hp	Building 1580
28	Emergency Generator	398 hp	Building 3406
29	Emergency Generator	47 hp	Building 3567
30	Fire Pump	275 hp	Building 2089
31	Fire Pump #1	235 hp	Building 1572
32	Fire Pump #2	235 hp	Building 1572
33	Fire Pump #3	235 hp	Building 1572
34	Fire Pump #4	235 hp	Building 1572
35	Fire Pump #1	240 hp	Building 2080
36	Fire Pump #2	240 hp	Building 2080
37	Fire Pump	105 kW	Building 3498
38	Fire Pump #1	120 hp	Building 5009
39	Fire Pump #2	120 hp	Building 5009
40	Waste Oil-Fired Boiler	2.6 MMBtu/hr	Building 5007
???	Distillate Fired Boilers (23)	Varies	Varies
???	Waste Oil-Fired Boiler	2.5 gal/hr	Building 3476
???	Waste Oil-Fired Boiler	2.5 gal/hr	Building 3476

Five-Step BACT Determinations

The following sections explain the steps used to determine BACT for NOx, PM-2.5, and SO_2 for the applicable equipment.

Step 1 Identify All Potentially Available Control Technologies

The Department identifies all available control technologies for the EU and the pollutant under consideration. This includes technologies used throughout the world or emission reductions through the application of available control techniques, changes in process design, and/or operational limitations. To assist in identifying available controls, the Department reviews available controls listed on the Reasonably Available Control Technology (RACT), BACT, and Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC). The RBLC is an EPA database where permitting agencies nationwide post imposed BACT for PSD sources. In addition to the RBLC search, the Department used several search engines to look for emerging and tried technologies used to control NOx, PM-2.5, and SO_2 emissions from equipment similar to those listed in Table A and Table B.

Step 2 Eliminate Technically Infeasible Control Technologies:
The Department evaluates the technical feasibility of each control option based on source specific factors in relation to each EU subject to BACT. Based on sound documentation and demonstration, the Department eliminates control technologies deemed technically infeasible due to physical, chemical, and engineering difficulties.

Step 3 Rank the Remaining Control Technologies by Control Effectiveness
The Department ranks the remaining control technologies in order of control effectiveness with the most effective at the top.

Step 4 Evaluate the Most Effective Controls and Document the Results as Necessary
The Department reviews the detailed information in the BACT analysis about the control efficiency, emission rate, emission reduction, cost, environmental, and energy impacts for each option to decide the final level of control. The analysis must present an objective evaluation of both the beneficial and adverse energy, environmental, and economic impacts. A proposal to use the most effective option does not need to provide the detailed information for the less effective options. If cost is not an issue, a cost analysis is not required. Cost effectiveness for a control option is defined as the total net annualized cost of control divided by the tons of pollutant removed per year. Annualized cost includes annualized equipment purchase, erection, electrical, piping, insulation, painting, site preparation, buildings, supervision, transportation, operation, maintenance, replacement parts, overhead, raw materials, utilities, engineering, start-up costs, financing costs, and other contingencies related to the control option. Sections 3, 4, and 5, present the Department's BACT determinations for NOx, PM-2.5, and SO_2.

Step 5 Select BACT
The Department selects the most effective control option not eliminated in Step 4 as BACT for the pollutant and EU under review and lists the final BACT requirements determined for each EU in this step. A project may achieve emission reductions through the application of available technologies, changes in process design, and/or operational limitations. The Department reviewed Fort Wainwright's BACT analysis and made BACT determinations for NOx, PM-2.5, and SO_2 for Fort Wainwright. These BACT determinations are based on the information submitted by Fort Wainwright in their analysis, information from vendors, suppliers, sub-contractors, RBLC, and an exhaustive internet search.

3. BACT DETERMINATION FOR NOx

The NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC is planning to submit with the Serious SIP a final precursor demonstration as justification not to require NOx controls. Please see the precursor demonstration for NOx posted at http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip-development. The PM2.5 NAAQS Final SIP Requirements Rule states if the state determines through a precursor demonstration that controls for a precursor gas are not needed for attaining the standard, then the controls identified as BACT/BACM or Most Stringent Measure for the precursor gas are not required to be implemented.[2] Final approval of the precursor demonstration is at the time of the Serious SIP approval.

Fort Wainwright has six existing 230 million British Thermal Units (MMBtu)/hr spreader-stoker type boilers that burn coal to produce steam for stationary source-wide heating and power. It also contains small and large emergency engines, fire pumps, and generators, diesel-fired boilers, and material handling equipment subject to BACT. The Department reviewed the control technologies Fort Wainwright identified in their analysis and made a NOx BACT finding for the EUs listed in Tables A and B.

The Department based its NOx assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by Golden Valley Electric Association (GVEA) for the North Pole Power Plant and Zehnder Facility, Aurora Energy, LLC (Aurora) for the Chena Power Plant, U.S. Army Corps of Engineers (US Army) for Fort Wainwright, and the University of Alaska Fairbanks (UAF) for the Fairbanks Campus Power Plant.

3.1 NOx BACT for the Industrial Coal-Fired Boilers

Possible NOx emission control technologies for coal-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.110, Coal Combustion in Industrial Size Boilers and Furnaces. The search results for coal-fired boilers are summarized in Table 3-1.

Table 3-1. RBLC Summary of NOx Control for Industrial Coal-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Selective Catalytic Reduction	9	0.05 – 0.08
Selective Non-Catalytic Reduction	18	0.07 – 0.36
Low NOx Burners	18	0.07 – 0.3
Overfire Air	8	0.07 – 0.3
Good Combustion Practices	2	0.1 – 0.6

RBLC Review
A review of similar units in the RBLC indicates selective catalytic reduction, selective non-

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf

catalytic reduction, low NOx burners, overfire air, and good combustion practices are the principle NOx control technologies installed on industrial coal-fired boilers. The lowest NOx emission rate in the RBLC is 0.05 lb/MMBtu.

Step 1- Identification of NOx Control Technologies for the Industrial Coal-Fired Boilers
From research, the Department identified the following technologies as available for control of NOx emissions from industrial coal-fired boilers:

(a) Selective Catalytic Reduction (SCR)[3]
SCR is a post-combustion gas treatment technique for reducing nitric oxide (NO) and nitrogen dioxide (NO_2) in the boiler exhaust stream to molecular nitrogen (N_2), water, and oxygen (O_2). In the SCR process, aqueous or anhydrous ammonia (NH_3) is injected into the flue gas upstream of a catalyst bed. The catalyst lowers the activation energy of the NOx decomposition reaction. NOx and NH_3 combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental N_2 and water. Depending on the overall NH_3-to-NOx ratio, removal efficiencies are generally 70 to 90 percent. Challenges associated with using SCR on industrial boilers include a narrow window of acceptable inlet and exhaust temperatures (500°F to 800°F), emission of NH_3 into the atmosphere (NH_3 slip) caused by non-stoichiometric reduction reaction, and disposal of depleted catalysts. The Department considers SCR a technically feasible control technology for the industrial coal-fired boilers.

(b) Selective Non-Catalytic Reduction (SNCR)[4]
SNCR involves the non-catalytic decomposition of NOx in the flue gas to N_2 and water using reducing agents such as urea or NH_3. The process utilizes a gas phase homogeneous reaction between NOx and the reducing agent within a specific temperature window. The reducing agent must be injected into the flue gas at a location in the unit that provides the optimum reaction temperature and residence time. The NH_3 process (trade name-Thermal DeNOx) requires a reaction temperature window of 1,600°F to 2,200°F. In the urea process (trade name–NO_xOUT), the optimum temperature ranges between 1,600°F and 2,100°F. Expected NOx removal efficiencies are typically between 40 to 62 percent, according to the RBLC, or between 30 and 50 percent reduction, according to the EPA fact sheet (EPA-452/F-03-031). The Department considers SNCR a technically feasible control technology for the industrial coal-fired boilers.

(c) Non-Selective Catalytic Reduction (NSCR)
NSCR simultaneously reduces NOx and oxidizes CO and hydrocarbons in the exhaust gas to N_2, carbon dioxide (CO_2), and water. The catalyst, usually a noble metal, causes the reducing gases in the exhaust stream (hydrogen, methane, and CO) to reduce both NO and NO_2 to N_2 at a temperature between 800°F and 1,200°F, below the expected temperature of the coal-fired boiler flue gas. NSCR requires a low excess O_2 concentration in the exhaust gas stream to be effective because the O_2 must be depleted

[3] https://www3.epa.gov/ttncatc1/dir1/fscr.pdf
[4] https://www3.epa.gov/ttncatc1/dir1/fsncr.pdf

before the reduction chemistry can proceed. NSCR is only effective with rich-burn gas-fired units that operate at all times with an air/fuel ratio controller at or close to stoichiometric conditions. Coal-fired boilers operate under conditions far more fuel-lean than required to support NSCR. The Department's research did not identify NSCR as a control technology used to control NOx emissions from large coal-fired boilers installed at any facility after 2005. The Department does not consider NSCR a technically feasible control technology for the industrial coal-fired boilers.

(d) Low NOx Burners (LNBs)
Using LNBs can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature. Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 60% but under certain conditions, higher reductions are possible. Air staging, or two-stage combustion, is generally described as the introduction of overfire air into the boiler or furnace. Overfire air is the injection of air above the main combustion zone. As indicated by EPA's AP-42, LNBs are applicable to tangential and wall-fired boilers of various sizes but are not applicable to other boiler types such as cyclone furnaces or stokers. The Department does not consider LNBs a technically feasible control technology for the existing stoker type coal-fired boilers.

(e) Circulating Fluidized Bed (CFB)
In a fluidized bed combustor, fuel is introduced to a bed of either sorbent (limestone) or inert material (usually sand) that is fluidized by an upward flow of air. This upward air flow allows for better mixing of the gas and solids to create a better heat transfer and chemical reactions. Combustion takes place in the bed at a lower temperature than other boiler types which lowers the formation of thermally generated NOx. For the purposes of this report, a control technology does not include passive control measures that act to prevent pollutants from forming such as inherent process design features or characteristics. The Department does not consider CFB a technically feasible control technology to retrofit the existing coal-fired boilers.

(f) Low Excess Air (LEA)
Boiler operation with low excess air is considered an integral part of good combustion practices because this process can maximize the boiler efficiency while controlling the formation of NOx. Boilers operated with five to seven percent excess air typically have peak NOx formation from both peak combustion temperatures and chemical reactions. At both lower and higher excess air concentrations the formation of NOx is reduced. At higher levels of excess air, an increase in the formation of CO occurs. CO can increase exponentially at very high levels of excess air and the combustion efficiency is greatly reduced. As a result, the preference is to reduce excess air such that both NOx and CO generation is minimized and the boiler efficiency is optimized. Only one RLBC entry identified low excess air technology as a NOx control alternative for a mass-feed stoker designed boiler. Boilers are regularly designed to operate with low excess air as described

in the previous LNB discussion. The Department considers LEA a technically feasible control technology for the industrial coal-fired boilers.

(g) Good Combustion Practices (GCPs)
GCPs typically include the following elements:

1. Sufficient residence time to complete combustion;
2. Providing and maintaining proper air/fuel ratio;
3. High temperatures and low oxygen levels in the primary combustion zone; and
4. High enough overall excess oxygen levels to complete combustion and maximize thermal efficiency.

Combustion efficiency is dependent on the gas residence time, the combustion temperature, and the amount of mixing in the combustion zone. GCPs are accomplished primarily through combustion chamber design as it relates to residence time, combustion temperature, air-to-fuel mixing, and excess oxygen levels. The Department considers GCPs a technically feasible control technology for the industrial coal-fired boilers.

(h) Fuel Switching
This evaluation considers retrofit of existing coal-fired boilers. It is assumed that use of another type of coal would not reduce NOx emissions. Therefore, the Department does not consider the use of an alternate fuel to be a technically feasible control technology for the industrial coal-fired boilers.

(i) Steam / Water Injection
Steam/water injection into the combustion zone reduces the firing temperature in the combustion chamber and has been traditionally associated with reducing NOx emissions from gas combustion turbines but not coal-fired boilers. In addition, steam/water has several disadvantages, including increases in carbon monoxide and un-burned hydrocarbon emissions and increased fuel consumption. Further, the Department found that steam or water injection is not listed in the EPA RBLC for use in any coal-fired boilers and it would be less efficient at controlling NOx emissions than SCR. Therefore, the Department does not consider steam or water injection to be a technically feasible control option for the existing coal-fired boilers.

(j) Reburn
Reburn is a combustion hardware modification in which the NOx produced in the main combustion zone is reduced in a second combustion zone downstream. This technique involves withholding up to 40 percent (at full load) of the heat input to the main combustion zone and introducing that heat input above the top row of burners to create a reburn zone. Reburn fuel (natural gas, oil, or pulverized coal) is injected with either air or flue gas to create a fuel-rich zone that reduces the NOx created in the main combustion zone to nitrogen and water vapor. The fuel-rich combustion gases from the reburn zone are completely combusted by injecting overfire air above the reburn zone. Reburn may be applicable to many boiler types firing coal as the primary fuel, including tangential, wall-fired, and cyclone boilers. However, the application and effectiveness are site-specific because each boiler is originally designed to achieve specific steam conditions and

capacity which may be altered due to reburn. Commercial experience is limited; however, this limited experience does indicate NOx reduction of 50 to 60 percent from uncontrolled levels may be achieved. Reburn combustion control would require significant changes to the design of the existing boilers. Therefore, the Department does not consider reburn to be a technically feasible control technology to retrofit the existing industrial coal-fired boilers.

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Coal-Fired Boilers
As explained in Step 1 of Section 3.1, the Department does not consider non-selective catalytic reduction, low NOx burners, circulating fluidized beds, fuel switching, steam/water injection, or reburn as technically feasible technologies to control NO_x emissions from existing industrial coal-fired boilers.

Step 3 - Rank the Remaining NOx Control Technologies for Industrial Coal-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from the coal-fired industrial boilers:

(a) Selective Catalytic Reduction (70% - 90% Control)
(b) Selective Non-Catalytic Reduction (30% - 50% Control)
(g) Good Combustion Practices (Less than 40% Control)
(f) Low Excess Air (10% - 20% Control)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright provided an economic analysis for the installation of selective catalytic reduction and selective non-catalytic reduction. A summary of the analysis is shown below:

Table 3-2. Fort Wainwright Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
SCR	177	88	$13,860,931	$2,222,777	$25,166
SNCR	105	52	$5,598,476	$936,162	$17,852
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

Fort Wainwright contends that the economic analysis indicates the level of NOx reduction does not justify the use of selective catalytic reduction or selective non-catalytic reduction for the coal-fired boilers based on the excessive cost per ton of NOx removed per year.

Fort Wainwright proposes the following as BACT for NOx emissions from the coal-fired boilers:

(a) NOx emissions from the operation of the coal-fired boilers will be controlled with good combustion practices and injection of overfire air with oxygen trim systems.

(b) NOx emissions from the coal-fired boilers will not exceed 0.46 lb/MMBtu over a 3-hour averaging period.

(c) Initial compliance with the proposed NOx emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

Department Evaluation of BACT for NOx Emissions from the Industrial Coal-Fired Boilers
The Department revised the cost analyses provided by Fort Wainwright for the installation of SCR and SNCR using the cost estimating procedures identified in EPA's May 2016 Air Pollution Control Cost Estimation Spreadsheet for Selective Catalytic Reduction,[5] and Selective Non-Catalytic Reduction,[6] using the unrestricted potential to emit from the six coal-fired boilers combined, a baseline emission rate of 0.58 lb NOx/MMBtu,[7] a retrofit factor of 1.5 for a difficult retrofit, a NOx removal efficiency of 90% and 50% for SCR and SNCR respectively, an interest rate of 5.5% (current bank prime interest rate), and a 20 year equipment life. A summary of the analysis is shown below:

Table 3-3. Department Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	1,447	1,302	$59,328,700	$6,816,393	$5,234
SNCR	1,447	723	$9,247,363	$1,628,874	$2,251
Capital Recovery Factor = 0.0837 (5.5% interest rate for a 20 year equipment life)					

The Department's economic analysis indicates the level of NOx reduction justifies the use of selective catalytic reduction or selective non-catalytic reduction as BACT for the coal-fired boilers located in the Serious PM-2.5 nonattainment area.

Step 5 - Selection of NOx BACT for the Industrial Coal-Fired Boilers
The Department's finding is that selective catalytic reduction and selective non-catalytic reduction are both economically and technically feasible control technologies for NOx. Since selective catalytic reduction has a higher control efficiency, it is selected as BACT to control NOx emissions from the industrial coal-fired boilers.

The Department's finding is that BACT for NOx emissions from the coal-fired boilers is as follows:

(a) NOx emissions from DU EUs 1 through 6 shall be controlled by operating and maintaining SCR at all times the units are in operation;

(b) NOx emissions from DU EUs 1 through 6 shall not exceed 0.060 lb/MMBtu averaged over a 3-hour period; and

(c) Initial compliance with the proposed NOx emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

[5] https://www3.epa.gov/ttn/ecas/docs/scr_cost_manual_spreadsheet_2016_vf.xlsm
[6] https://www3.epa.gov/ttn/ecas/docs/sncr_cost_manual_spreadsheet_2016_vf.xlsm
[7] Emission factor from AP-42 Table 1.1-3 for spreader stoker sub-bituminous coal (8.8 lb NOx/ton) and converted to lb/MMBtu using heat value for Usibelli Coal of 7,560 Btu/lb, http://www.usibelli.com/coal/data-sheet.

Table 3-4 lists the proposed NOx BACT determination for this facility along with those for other coal-fired boilers in the Serious PM-2.5 nonattainment area.

Table 3-4. Comparison of NOx BACT for Coal-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	6 Coal-Fired Boilers	1,380 MMBtu/hr	0.06 lb/MMBtu[8]	Selective Catalytic Reduction
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.02 lb/MMBtu[9]	Selective Catalytic Reduction
Chena	4 Coal-Fired Boilers	497 MMBtu/hr	0.05 lb/MMBtu[10]	Selective Catalytic Reduction

3.2 NOx BACT for the Diesel-Fired Boilers

Possible NOx emission control technologies for diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.220, Commercial/Institutional Size Boilers (<100 MMBtu/hr). The search results for diesel-fired boilers are summarized in Table 3-5.

Table 3-5. RBLC Summary of NOx Control for Diesel-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Low-NOx Burner	8	0.023 - 0.14
Good Combustion Practices	1	0.01
No Control Specified	2	0.070 - 0.12

RBLC Review
A review of similar units in the RBLC indicates low-NOx burners and good combustion practices are the principle NOx control technologies installed on diesel-fired boilers. The lowest NOx emission rate listed in the RBLC is 0.01 lb/MMBtu.

Step 1 - Identification of NOx Control Technologies for the Diesel-Fired Boilers
From research, the Department identified the following technologies as available for control of NOx emissions from diesel-fired boilers:

(a) Low NOx Burners (LNBs)
The theory of LNBs was discussed in detail in the NOx BACT for the coal-fired boilers and will not be repeated here. The Department considers LNB a technically feasible control technology for the diesel-fired boilers.

(b) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation a technically feasible control technology for the diesel-fired boilers.

[8] Calculated using a 90% NOx control efficiency for SCR with uncontrolled emission factor from AP-42 Table 1.1-3 for spreader stoker sub-bituminous coal (8.8 lb NOx/ton) and converted to lb/MMBtu using heat value for Usibelli Coal of 7,560 Btu/lb, http://www.usibelli.com/coal/data-sheet.
[9] Calculated using a 90% NOx control efficiency for SCR with uncontrolled emission rate from 40 C.F.R. 60.44b(l)(1) [NSPS Subpart Db].
[10] Calculated using a 90% NOx control efficiency for SCR with uncontrolled emission rate from most recent NOx source test, which occurred on Oct 27, 2018.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the coal-fired boilers and will not be repeated here. The Department considers GCPs a technically feasible control technology for the diesel-fired boilers.

(d) Flue Gas Recirculation (FGR)
Flue gas recirculation involves extracting a portion of the flue gas from the economizer section or air heater outlet and readmitting it to the furnace through the furnace hopper, the burner windbox, or both. This method reduces the concentration of oxygen in the combustion zone and may reduce NOx by as much as 40 to 50 percent in some boilers. Chapter 1.3-7 from AP-42 indicates that FGR can require extensive modifications to the burner and windbox and can result in possible flame instability at high FGR rates. The Department does not consider FGR a technically feasible control technology for the diesel-fired boilers.

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Diesel-Fired Boilers
As explained in Step 1 of Section 3.2, the Department does not consider flue gas recirculation as technically feasible technology for the diesel-fired boilers.

Step 3 - Rank the Remaining NOx Control Technologies for the Diesel-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from the diesel-fired boilers.

(b)	Limited Operation	(94% Control)
(a)	Low NOx Burners	(35% - 55% Control)
(c)	Good Combustion Practices	(Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright proposes the following as BACT for NOx emissions from the diesel-fired boilers:

(a) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of operation;

(b) Combined operating limit of 600 hours per year for FWA EUs 8, 9, and 10; and

(c) Limiting operation of the other 24 diesel-fired boilers to testing, maintenance, and emergency use with the exception of the waste fuel boilers.

Department Evaluation of BACT for NOx Emissions from the Diesel-Fired Boilers.

The Department reviewed Fort Wainwright's proposal and finds that the 27 diesel-fired boilers have a combined potential to emit (PTE) of less than three tons per year (tpy) for NOx based on non-emergency operation of 500 hours per year. At three tpy, the cost effectiveness in terms of dollars per ton for add-on pollution control for these units is economically infeasible.

Step 5 - Selection of NOx BACT for the Diesel-Fired Boilers
The Department's finding is that BACT for NOx emissions from the diesel-fired boilers is as follows:

(a) NOx emissions from the diesel-fired boilers shall not exceed 0.15 lb/MMBtu[11];

(b) Combined operating limit of 600 hours per year for FWA EUs 8, 9, and 10;

(c) Limit non-emergency operation of the 27 diesel fired boilers, with the exception of the waste-fuel boilers, to no more than 500 hours per year, for maintenance checks and readiness testing; and

(d) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of operation.

Table 3-6 lists the proposed NOx BACT determination for this facility along with those for other diesel-fired boilers rated at less than 100 MMBtu/hr in the Serious PM-2.5 nonattainment area.

Table 3-6. Comparison of NOx BACT for the Diesel-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	27 Diesel-Fired Boilers	< 100 MMBtu/hr	0.15 lb/MMBtu	Limited Operation Good Combustion Practices
UAF	3 Diesel-Fired Boilers	< 100 MMBtu/hr	0.15 lb/MMBtu	Limited Operation Good Combustion Practices
GVEA Zehnder	2 Diesel-Fired Boilers	< 100 MMBtu/hr	0.15 lb/MMBtu	Low NOx Burners

3.3 NOx BACT for the Large Diesel-Fired Engines, Fire Pumps, and Generators

Possible NOx emission control technologies for large engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.100 to 17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 3-7.

Table 3-7. RBLC Summary of NOx Control for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Selective Catalytic Reduction	3	0.5 - 0.7
Other Add-On Control	1	1.0
Federal Emission Standards	13	3.0 - 6.9
Good Combustion Practices	31	3.0 - 13.5
No Control Specified	60	2.8 - 14.1

RBLC Review
A review of similar units in the RBLC indicates selective catalytic reduction, good combustion practices, and compliance with the federal emission standards are the principle NOx control technologies installed on large diesel-fired engines. The lowest NOx emission rate listed in the RBLC is 0.5 g/hp-hr.

[11] Emission rate from AP-42 Table 1.3-1 for boilers smaller than 100 MMBtu/hr (20 lb/1,000 gallons of diesel) and converted to lb/MMBtu assuming 0.137 MMBtu/gal diesel (AP-42).

Step 1 - Identification of NOx Control Technology for the Large Diesel-Fired Engines
From research, the Department identified the following technologies as available for control of NOx emissions from diesel-fired engines rated at 500 hp or greater:

(a) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT for the coal-fired boilers and will not be repeated here. The Department considers SCR a technically feasible control technology for the large diesel-fired engines.

(b) Turbocharger and Aftercooler
Turbocharger technology involves the process of compressing intake air in a turbocharger upstream of the air/fuel injection. This process boosts the power output of the engine. The air compression increases the temperature of the intake air so an aftercooler is used to reduce the intake air temperature. Reducing the intake air temperature helps lower the peak flame temperature which reduces NOx formation in the combustion chamber. The Department considers turbocharger and aftercooler a technically feasible control technology for the large diesel-fired engines.

(c) Fuel Injection Timing Retard (FITR)
FITR reduces NOx emissions by the delay of the fuel injection in the engine from the time the compression chamber is at minimum volume to a time the compression chamber is expanding. Timing adjustments are relatively straightforward. The larger volume in the compression chamber produces a lower peak flame temperature. With the use of FITR the engine becomes less fuel efficient, particulate matter emissions increase, and there is a limit with respect to the degree the timing may be retarded because an excessive timing delay can cause the engine to misfire. The timing retard is generally limited to no more than three degrees. Diesel engines may also produce more black smoke due to a decrease in exhaust temperature and incomplete combustion. FITR can achieve up to 50 percent NOx reduction. Due to the increase in particulate matter emissions resulting from FITR, this technology will not be carried forward.

(d) Ignition Timing Retard (ITR)
ITR lowers NOx emissions by moving the ignition event to later in the power stroke, after the piston has begun to move downward. Because the combustion chamber volume is not at a minimum, the peak flame temperature is not as high, which lowers combustion temperature and produces less thermal NOx. Use of ITR can cause an increase in fuel usage, an increase in particulate matter emissions, and engine misfiring. ITR can achieve between 20 to 30 percent NOx reduction. Due to the increase in the particulate matter emissions resulting from ITR, this technology will not be carried forward.

(e) Federal Emission Standards
RBLC NOx determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 Subpart IIII, 40 C.F.R 63 Subpart ZZZZ, non-road engines (NREs), or EPA tier certifications. Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005.

The Department considers meeting the technology based New Source Performance Standards (NSPS) of Subpart IIII as a technically feasible control technology for the large diesel-fired engines.

(f) Limited Operation
FWA EUs 11, 12, and 13 currently operate under a combined annual limit of less than 600 hours per year to avoid classification as a Prevention of Significant Deterioration (PSD) major modification for NOx. Limiting the operation of emissions units reduces the potential to emit of those units. The Department considers limited operation a technically feasible control technology for the large diesel-fired engines.

(g) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the coal-fired boilers and will not be repeated here. The Department considers GCPs a technically feasible control technology for the large diesel-fired engines.

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Large Engines
As explained in Step 1 of Section 3.3, the Department does not consider fuel injection timing retard and ignition timing retard as technically feasible technologies to control NOx emissions from the large diesel-fired engines.

Step 3 - Rank the Remaining NOx Control Technologies for the Large Diesel-Fired Engines
The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from the large diesel-fired engines.

(f)	Limited Operation	(94% Control)
(a)	Selective Catalytic Reduction	(90% Control)
(g)	Good Combustion Practices	(Less than 40% Control)
(b)	Turbocharger and Aftercooler	(6% – 12% Control)
(e)	Federal Emission Standards	(Baseline)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright proposes the following as BACT for NOx emissions from the large diesel-fired engines:

(a) Combined operating limit of 600 hours per year for FWA EUs 11, 12, and 13; and

(b) For engines manufactured after the applicability dates of 40 C.F.R. 60 Subpart IIII, BACT is selected as compliance with 40 C.F.R Part 60 Subpart IIII. For older engines, compliance with 40 C.F.R. 63 Subpart ZZZZ is proposed as BACT.

Department Evaluation of BACT for NOx Emissions from the Large Diesel-Fired Engines

The Department reviewed Fort Wainwright's proposal and finds that NOx emissions from the large diesel-fired engines can additionally be controlled by limiting the use of the units during non-emergency operation as well as complying with the applicable federal emission standards.

Step 5 - Selection of NOx BACT for the Large Diesel-Fired Engines
The Department's finding is that the BACT for NOx emissions from the large diesel-fired engines is as follows:

(a) Combined operating limit of 600 hours per year for FWA EUs 11, 12, and 13;

(b) Limit EU 8 to 500 hours per year;

(c) Limit non-emergency operation of DU EUs 8, 10, 11, 13, and 15 to no more than 100 hours per year each for maintenance checks and readiness testing;

(d) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of operation; and

(e) Comply with the numerical BACT emission limits listed in Table 3-8 for NOx.

Table 3-8 Proposed NOx BACT Limits for the Large Diesel-Fired Engines

Location	EU	Year	Description	Size	Status	BACT Limit	Proposed BACT
DU	8	2009	Generator Engine	2,937 hp	Certified Engine	4.8 g/hp-hr	Limited Operation for Non-Emergency Use (100 hours per year each) Good Combustion Practices
DU	10	2010	Generator Engine	762 hp	Certified Engine	4.8 g/hp-hr	
DU	11	2010	Generator Engine	762 hp	Certified Engine	4.8 g/hp-hr	
DU	13	2008	Generator Engine	587 hp	Certified Engine	3.0 g/hp-hr	
DU	15	2005	Generator Engine	1,059 hp	Manufacturer Information	5.75 g/hp-hr	
FWA	11	2003	Caterpillar 3512	1,206 hp	AP-42 Table 3.4-1	10.9 lb/hp-hr	Limit combined operation to 600 hours per year
FWA	12	2003	Caterpillar 3512	1,206 hp	AP-42 Table 3.4-1	10.9 lb/hp-hr	
FWA	13	2003	Caterpillar 3512	1,206 hp	AP-42 Table 3.4-1	10.9 lb/hp-hr	

Table 3-9 lists the proposed NOx BACT determination for this facility along with those for other diesel-fired engines rated at more than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 3-9. Comparison of NOx BACT for Large Diesel-Fired Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	8 Large Diesel-Fired Engines	> 500 hp	3.0 – 10.9 g/hp-hr	Limited Operation Good Combustion Practices Federal Emission Standards
UAF	Large Diesel-Fired Engine	13,266 hp	1.3 g/hp-hr	Selective Catalytic Reduction Turbocharger and Aftercooler Good Combustion Practices Limited Operation
GVEA North Pole	Large Diesel-Fired Engine	600 hp	10.9 g/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp (each)	3.7 g/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation

3.4 NOx BACT for the Small Emergency Engines, Fire Pumps, and Generators

Possible NOx emission control technologies for small engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 17.210, Small Internal Combustion Engines (<500 hp). The search results for small diesel-fired engines are summarized in Table 3-10.

Table 3-10. RBLC Summary for NOx Control for Small Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Federal Emission Standards	5	2.2 – 4.8
Good Combustion Practices	25	2.0 – 9.5
Limited Operation	4	3.0
No Control Specified	25	2.6 – 5.6

RBLC Review
A review of similar units in the RBLC indicates limited operation, good combustion practices, and compliance with the federal emission standards are the principle NOx control technologies for small diesel-fired engines. The lowest NOx emission rate listed in the RBLC is 2.0 g/hp-hr.

Step 1 - Identification of NOx Control Technology for the Small Diesel-Fired Engines
From research, the Department identified the following technologies as available for control of NOx emissions from diesel-fired engines rated at less than 500 hp:

(a) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT for the coal-fired boiler and will not be repeated here. The Department considers SCR a technically feasible control technology for the small diesel-fired engines.

(b) Turbocharger and Aftercooler
The theory of turbocharger and aftercooler was discussed in detail in the NOx BACT for the large diesel-fired engine and will not be repeated here. The Department considers a turbocharger and aftercooler a technically feasible control technology for the small diesel-fired engines.

(c) Ignition Timing Retard (ITR)
The theory of ITR was discussed in detail in the NOx BACT for the coal-fired boilers and will not be repeated here. Due to the increase in particulate matter emissions resulting from ITR, this technology will not be carried forward.

(d) Federal Emission Standards
RBLC NOx determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 Subpart IIII, 40 C.F.R 63 Subpart ZZZZ, non-road engines (NREs), or EPA tier certifications. Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. The Department considers meeting the technology based NSPS of Subpart IIII as a technically feasible control technology for the small diesel-fired engines.

(e) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation as a technically feasible control technology for the small diesel-fired engines.

(f) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fired boiler and will not be repeated here. The Department considers GCPs a technically feasible control technology for the small diesel-fired engines.

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Small Engines
As explained in Step 1 of Section 3.4, the Department does not consider ignition timing retard as a technically feasible technology to control NOx emissions from the small diesel-fired engines.

Step 3 - Rank the Remaining NOx Control Technologies for the Small Engines
The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from the small diesel-fired engines.

(e)	Limited Operation	(94% Control)
(a)	Selective Catalytic Reduction	(90% Control)
(b)	Turbocharger and Aftercooler	(6% – 12% Control)
(f)	Good Combustion Practices	(Less than 40% Control)
(d)	Federal Emission Standards	(Baseline)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright proposes the following as BACT for NOx emissions from the small diesel-fired engines:

(a) Good Combustion Practices; and

(b) For engines manufactured after the applicability dates of 40 C.F.R. 60 Subpart IIII, BACT is selected as compliance with 40 C.F.R Part 60 Subpart IIII. For older engines, compliance with 40 C.F.R. 63 Subpart ZZZZ is proposed as BACT.

Department Evaluation of BACT for NOx Emissions from Small Diesel-Fired Engines

The Department reviewed Fort Wainwright's proposal and found that in addition to maintaining good combustion practices and complying with federal emission standards, limiting operation of the small diesel-fired engines during non-emergency operation to no more than 100 hours per year each is BACT for NOx emissions.

Step 5 - Selection of NOx BACT for the Small Diesel-Fired Engines
The Department's finding is that the BACT for NOx emissions from the small diesel-fired engines is as follows:

(a) Limit non-emergency operation of DU EUs 9, 12, 14, 16 through 28, 29a, 30, 31a, 32, 33, 34, 35, 36, and FWA EUs 26 through 39 to no more than 100 hours per year each for maintenance checks and readiness testing;

(b) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of operation; and

(c) Comply with the numerical BACT emission limits listed in Table 3-11 for NOx.

Table 3-11. Proposed NOx BACT Limits for the Small Diesel-Fired Engines

Location	EU	Year	Description	Size	Status	BACT Limit	Proposed BACT
DU	9	1988	Generator Engine	353 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	Limited Operation for Non-Emergency Use (100 hours per year each) Good Combustion Practices
DU	12	2002	Generator Engine	82 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	14	2008	Generator Engine	320 hp	Certified Engine	4.0 g/kW-hr	
DU	16	2005	Generator Engine	212 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	17	2007	Generator Engine	176 hp	Permit condition 23.1c	6.9 g/hp-hr	
DU	18	2005	Generator Engine	212 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	19	2007	Generator Engine	71 hp	Certified Engine	7.5 g/kW-hr	
DU	20	1976	Generator Engine	35 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	21	2001	Generator Engine	95 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	22	1989	Generator Engine	35 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	23	2003	Generator Engine	155 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	24	1993	Generator Engine	50 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	25	2011	Generator Engine	18 hp	Certified Engine	7.5 g/kW-hr	
DU	26	2003	Generator Engine	68 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	27	2010	Generator Engine	274 hp	Certified Engine	4.0 g/kW-hr	
DU	28	2010	Generator Engine	274 hp	Certified Engine	4.0 g/kW-hr	
DU	30	1952	Lift Pump Engine	75 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	32	1955	Lift Pump Engine	75 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	33	1994	Lift Pump Engine	75 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	34	1995	Well Pump Engine	220 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	35	2009	Well Pump Engine	55 hp	Certified Engine	4.7 g/kW-hr	
DU	36	1995	Well Pump Engine	220 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
DU	29a	2014	Lift Pump Engine	74 hp	Certified Engine	4.7 g/kW-hr	
DU	31a	2014	Lift Pump Engine	74 hp	Certified Engine	4.7 g/kW-hr	
FWA	26	2012	QSB7-G3 NR3	295 hp	Certified Engine	4.0 g/kW-hr	
FWA	27	2009	4024HF285B	67 hp	Certified Engine	4.7 g/kW-hr	
FWA	28	2007	CAT C9 GENSET	398 hp	Certified Engine	4.0 g/kW-hr	
FWA	29	ND	TM30UCM	47 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	30	2007	JW64-UF30	275 hp	Certified Engine	4.0 g/kW-hr	
FWA	31	1994	DDFP-04AT	235 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	32	1994	DDFP-04AT	235 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	33	1994	DDFP-04AT	235 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	34	1994	DDFP-04AT	235 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	35	1977	N-855-F	240 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	36	1977	N-855-F	240 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	37	2005	JU4H-UF40	94 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	38	1996	PDFP-06YT	120 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	
FWA	39	1996	PDFP-06YT	120 hp	AP-42, Table 3.3-1	0.031 lb/hp-hr	

Table 3-12 lists the proposed NOx BACT determination for this facility along with those for other diesel-fired engines rated at less than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 3-12. Comparison of NOx BACT for Small Diesel Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	41 Small Diesel-Fired Engines	< 500 hp	0.007 – 0.031 lb/hp-hr	Limited Operation for Non-Emergency Use (100 hours per year each) Good Combustion Practices
UAF	Six Small Diesel-Fired Engines	< 500 hp	0.0007 – 0.031 lb/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation

4. BACT DETERMINATION FOR PM-2.5

The Department based its PM-2.5 assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by GVEA for the North Pole Power Plant and Zehnder Facility, Aurora for the Chena Power Plant, US Army for Fort Wainwright, and UAF for the Combined Heat and Power Plant.

4.1 PM-2.5 BACT for the Industrial Coal-Fired Boilers

Possible PM-2.5 emission control technologies for coal-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.110, Coal Combustion in Industrial Size Boilers and Furnaces. The search results for coal-fired boilers are summarized in Table 4-1.

Table 4-1. RBLC Summary of PM-2.5 Control for Industrial Coal-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Pulse Jet Fabric Filters	4	0.012 – 0.024
Electrostatic Precipitators	2	0.02 – 0.03

RBLC Review

A review of similar units in the RBLC indicates that fabric filters and electrostatic precipitators are the principle particulate matter control technologies installed on industrial coal-fired boilers. The lowest PM-2.5 emission rate listed in RBLC is 0.012 lb/MMBtu.

Step 1 - Identification of PM-2.5 Control Technologies for the Industrial Coal-Fired Boilers

From research, the Department identified the following technologies as available for control of PM-2.5 emissions from industrial coal-fired boilers:

(a) Fabric Filters

Fabric filters or baghouses are comprised of an array of filter bags contained in housing. Air passes through the filter media from the "dirty" to the "clean" side of the bag. These devices undergo periodic bag cleaning based on the build-up of filtered material on the bag as measured by pressure drop across the device. The cleaning cycle is set to allow

operation within a range of design pressure drop. Fabric filters are characterized by the type of cleaning cycle: mechanical-shaker,[12] pulse-jet,[13] and reverse-air.[14] Fabric filter systems have control efficiencies of 95% to 99.9%, and are generally specified to meet a discharge concentration of filterable particulate (e.g., 0.01 grains per dry standard cubic feet). The Department considers fabric filters a technically feasible control technology for the industrial coal-fired boilers.

(b) Wet and Dry Electrostatic Precipitators (ESP)
ESPs remove particles from a gas stream by electrically charging particles with a discharge electrode in the gas path and then collecting the charged particles on grounded plates. The inlet air is quenched with water on a wet ESP to saturate the gas stream and ensure a wetted surface on the collection plate. This wetted surface along with a period deluge of water is what cleans the collection plate surface. Wet ESPs typically control streams with inlet grain loading values of 0.5 – 5 gr/ft^3 and have control efficiencies between 90% and 99.9%.[15] Wet ESPs have the advantage of controlling some amount of condensable particulate matter. The collection plates in a dry ESP are periodically cleaned by a rapper or hammer that sends a shock wave that knocks the collected particulate off the plate. Dry ESPs typically control streams with inlet grain loading values of 0.5 – 5 gr/ft^3 and have control efficiencies between 99% and 99.9%.[16] The Department considers ESP a technically feasible control technology for the industrial coal-fired boilers.

(c) Wet Scrubbers
Wet scrubbers use a scrubbing solution to remove PM/PM_{10}/$PM_{2.5}$ from exhaust gas streams. The mechanism for particulate collection is impaction and interception by water droplets. Wet scrubbers are configured as counter-flow, cross-flow, or concurrent flow, but typically employ counter-flow where the scrubbing fluid is in the opposite direction as the gas flow. Wet scrubbers have control efficiencies of 50% - 99%.[17] One advantage of wet scrubbers is that they can be effective on condensable particulate matter. A disadvantage of wet scrubbers is that they consume water and produce water and sludge. For fine particulate control, a venturi scrubber can be used, but typical loadings for such a scrubber are 0.1-50 grains/scf. The Department considers the use of wet scrubbers a technically feasible control technology for the industrial coal-fired boilers.

(d) Mechanical Collectors (Cyclones)
Cyclones are used in industrial applications to remove particulate matter from exhaust flows and other industrial stream flows. Dirty air enters a cyclone tangentially and the

[12] https://www3.epa.gov/ttn/catc/dir1/ff-shaker.pdf
[13] https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf
[14] https://www3.epa.gov/ttn/catc/dir1/ff-revar.pdf
[15] https://www3.epa.gov/ttn/catc/dir1/fwespwpi.pdf
https://www3.epa.gov/ttn/catc/dir1/fwespwpl.pdf
[16] https://www3.epa.gov/ttn/catc/dir1/fdespwpi.pdf
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[17] https://www3.epa.gov/ttn/catc/dir1/fcondnse.pdf
https://www3.epa.gov/ttn/catc/dir1/fiberbed.pdf
https://www3.epa.gov/ttn/catc/dir1/fventuri.pdf

centrifugal force moves the particulate matter against the cone wall. The air flows in a helical pattern from the top down to the narrow bottom before exiting the cyclone straight up the center and out the top. Large and dense particles in the stream flow are forced by inertia into the walls of the cyclone where the material then falls to the bottom of the cyclone and into a collection unit. Cleaned air then exits the cyclone either for further treatment or release to the atmosphere. The narrowness of the cyclone wall and the speed of the air flow determine the size of particulate matter that is removed from the stream flow. Cyclones are most efficient at removing large particulate matter (PM-10 or greater). Conventional cyclones are expected to achieve 0 to 40 percent PM-2.5 removal. High efficiency single cyclones are expected to achieve 20 to 70 percent PM-2.5 removal. The Department considers cyclones a technically feasible control technology for the industrial coal-fired boilers.

(e) Settling Chamber
Settling chambers appear only in the biomass fired boiler RBLC inventory for particulate control, not in the coal fired boiler RBLC inventory. This type of technology is a part of the group of air pollution control collectively referred to as "pre-cleaners" because the units are often used to reduce the inlet loading of particulate matter to downstream collection devices by removing the larger, abrasive particles. The collection efficiency of settling chambers is typically less than 10 percent for PM-10. The EPA fact sheet does not include a settling chamber collection efficiency for PM-2.5. The Department does not consider settling chambers a technically feasible control technology for the industrial coal-fired boilers.

(f) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the industrial coal-fired boilers and will not be repeated here. Proper management of the combustion process will result in a reduction of PM-2.5 emissions. The Department considers GCPs a technically feasible control technology for the industrial coal-fired boilers.

Step 2 - Eliminate Technically Infeasible PM-2.5 Control Technologies for the Coal-Fired Boilers
As explained in Step 1 of Section 4.1, the Department does not consider a settling chamber as a technically feasible technology to control particulate matter emissions from the industrial coal-fired boilers.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Industrial Coal-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 from the industrial coal-fired boilers:

(a)	Fabric Filters	(99.9% Control)
(b)	Electrostatic Precipitator	(99.6% Control)
(c)	Wet Scrubber	(50% – 99% Control)
(d)	Cyclone	(20% – 70% Control)
(f)	Good Combustion Practices	(Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright proposes the following as BACT for PM-2.5 emissions from the coal-fired boilers:

(a) PM-2.5 emissions from the operation of the coal-fired boilers shall be controlled by installing, operating, and maintaining a full stream baghouse.

(b) PM-2.5 emissions from the coal-fired boilers shall not exceed 0.05 gr/dscf over a 3-hour averaging period.

(c) Initial compliance with the proposed PM-2.5 emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

Step 5 - Selection of PM-2.5 BACT for the Industrial Coal-Fired Boilers
The Department's finding is that BACT for PM-2.5 emissions from the coal-fired boilers is as follows:

(a) PM-2.5 emissions from DU EUs 1 through 6 shall be controlled by operating and maintaining fabric filters (full stream baghouse) at all times the units are in operation;

(b) PM-2.5 emissions from DU EUs 1 through 6 shall not exceed 0.006 lb/MMBtu[18] averaged over a 3-hour period; and

(c) Initial compliance with the proposed PM-2.5 emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

Table 4-2 lists the proposed PM-2.5 BACT determination for this facility along with those for other industrial coal-fired boilers in the Serious PM-2.5 nonattainment area.

Table 4-2. Comparison of PM-2.5 BACT for Coal-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	6 Coal-Fired Boilers	1380 MMBtu/hr	0.006 lb/MMBtu[18]	Full stream baghouse
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.006 lb/MMBtu[18]	Fabric Filters

4.2 PM-2.5 BACT for the Diesel-Fired Boilers

Possible PM-2.5 emission control technologies for diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.220, Commercial/Institutional Size Boilers (<100 MMBtu/hr). The search results for diesel-fired boilers are summarized in Table 4-3.

Table 4-3. RBLC Summary of PM-2.5 Control for Diesel-Fired Boilers

Control Technology	Number of Determinations	Emission Limits
Good Combustion Practices	3	0.25 lb/gal
		0.1 tpy
		2.17 lb/hr

[18] Average soot blown run emission rate (rounded up) from worst coal-fired boiler tested at Fort Wainwright (Boiler No. 3) during most recent source test on April 19-22, 24, and 25, 2017.

RBLC Review
A review of similar units in the RBLC indicates good combustion practices are the principle PM-2.5 control technologies installed on diesel-fired boilers. The lowest PM-2.5 emission rate listed in the RBLC is 0.1 tpy.

Step 1 - Identification of PM-2.5 Control Technology for the Diesel-Fired Boilers
From research, the Department identified the following technologies as available for control of PM-2.5 emissions from diesel-fired boilers:

(a) Scrubbers
The theory behind scrubbers was discussed in detail in the PM-2.5 BACT for the industrial coal-fired boilers and will not be repeated here. The Department considers scrubbers as a technically feasible control technology for the diesel-fired boilers.

(b) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation a technically feasible control technology for the diesel-fired boilers.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the industrial coal-fired boilers and will not be repeated here. Proper management of the combustion process will result in a reduction of PM-2.5 emissions. The Department considers GCPs a technically feasible control technology for the diesel-fired boilers.

Step 2 - Eliminate Technically Infeasible PM-2.5 Control Technologies for Diesel-Fired Boilers
All identified control devices are technically feasible for the diesel-fired boilers.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Diesel-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 emissions from the diesel-fired boilers:

(a)	Scrubber	(50% - 99% Control)
(b)	Limited Operation	(94% Control)
(c)	Good Combustion Practices	(Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright proposes good combustion practices as BACT for PM-2.5 emissions from the diesel-fired boilers.

Department Evaluation of BACT for PM-2.5 Emissions from Diesel-Fired Boilers

The Department reviewed Fort Wainwright's proposal and finds that the 27 diesel-fired boilers have a combined PTE of less than one tpy for PM-2.5 based on non-emergency operation of 500 hours per year. At one tpy, the cost effectiveness in terms of dollars per ton for add-on pollution control for these units is economically infeasible.

Step 5 - Selection of PM-2.5 BACT for the Diesel-Fired Boilers

The Department's finding is that BACT for PM-2.5 emissions from the diesel-fired boilers is as follows:

(a) PM-2.5 emissions from the diesel-fired boilers shall not exceed 0.012 lb/MMBtu[19] averaged over a 3-hour period, with the exception of the waste fuel boilers which must comply with the State particulate matter emissions standard of 0.05 grains per dry standard cubic foot under 18 AAC 50.055(b)(1);

(b) Combined operating limit of 600 hours per year for FWA EUs 8, 9, and 10;

(c) Limit non-emergency operation of the 27 diesel fired boilers, with the exception of the waste-fuel boilers, to no more than 500 hours per year, for maintenance checks and readiness testing; and

(d) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of operation.

Table 4-4 lists the proposed PM-2.5 BACT determination for this facility along with those for other diesel-fired boilers rated at less than 100 MMBtu/hr in the Serious PM-2.5 nonattainment area.

Table 4-4. Comparison of PM-2.5 BACT for the Diesel-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	27 Diesel-Fired Boilers	< 100 MMBtu/hr	0.012 lb/MMBtu[19]	Good Combustion Practices
UAF	3 Diesel-Fired Boilers	< 100 MMBtu/hr	0.012 lb/MMBtu[19]	Limited Operation Good Combustion Practices
Zehnder	2 Diesel-Fired Boilers	< 100 MMBtu/hr	0.012 lb/MMBtu[19]	Good Combustion Practices

4.3 PM-2.5 BACT for the Large Diesel-Fired Engines, Fire Pumps, and Generators

Possible PM-2.5 emission control technologies for large engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.100-17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 4-5.

Table 4-5. RBLC Summary of PM-2.5 Control for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Federal Emission Standards	12	0.03 – 0.02
Good Combustion Practices	28	0.03 – 0.24
Limited Operation	11	0.04 – 0.17
Low Sulfur Fuel	14	0.15 – 0.17
No Control Specified	14	0.02 – 0.15

RBLC Review

A review of similar units in the RBLC indicates that good combustion practices, compliance with the federal emission standards, low ash/sulfur diesel, and limited operation are the principle

[19] Emission factor from AP-42 Table's 1.3-2 (total condensable particulate matter from No. 2 oil, 1.3 lb/1,000 gal) and 1.3-6 (PM-2.5 size-specific factor from distillate oil, 0.25 lb/1,000 gal) converted to lb/MMBtu.

PM-2.5 control technologies installed on large diesel-fired engines. The lowest PM-2.5 emission rate in the RBLC is 0.02 g/hp-hr.

Step 1 - Identification of PM-2.5 Control Technology for the Large Diesel-Fired Engines
From research, the Department identified the following technologies as available for control of PM-2.5 emissions from diesel-fired engines rated at 500 hp or greater:

(a) Diesel Particulate Filter (DPF)
DPFs are a control technology that are designed to physically filter particulate matter from the exhaust stream. Several designs exist which require cleaning and replacement of the filter media after soot has become caked onto the filter media. Regenerative filter designs are also available that burn the soot on a regular basis to regenerate the filter media. The Department considers DPF a technically feasible control technology for the large diesel-fired engines.

(b) Diesel Oxidation Catalyst (DOC)
DOC can reportedly reduce PM-2.5 emissions by 30% and PM emissions by 50%. A DOC is a form of "bolt on" technology that uses a chemical process to reduce pollutants in the diesel exhaust into decreased concentrations. They replace mufflers on vehicles, and require no modifications. More specifically, this is a honeycomb type structure that has a large area coated with an active catalyst layer. As CO and other gaseous hydrocarbon particles travel along the catalyst, they are oxidized thus reducing pollution. The Department considers DOC a technically feasible control technology for the large diesel-fired engines.

(c) Positive Crankcase Ventilation
Positive crankcase ventilation is the process of re-introducing the combustion air into the cylinder chamber for a second chance at combustion after the air has seeped into and collected in the crankcase during the downward stroke of the piston cycle. This process allows any unburned fuel to be subject to a second combustion opportunity. Any combustion products act as a heat sink during the second pass through the piston, which will lower the temperature of combustion and reduce the thermal NOx formation. The Department considers positive crankcase ventilation a technically feasible control technology for the large diesel-fired engines.

(d) Low Sulfur Fuel
Low sulfur fuel has been known to reduce particulate matter emissions. The Department considers low sulfur fuel as a feasible control technology for the large diesel-fired engines.

(e) Low Ash Diesel
Residual fuels and crude oil are known to contain ash forming components, while refined fuels are low ash. Fuels containing ash can cause excessive wear to equipment and foul engine components. The Department considers low ash diesel a technically feasible control technology for the large diesel-fired engines.

(f) Federal Emission Standards
RBLC PM-2.5 determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 NSPS Subpart IIII, 40 C.F.R 63 Subpart ZZZZ, non-road engines (NREs), or EPA tier certifications. NSPS Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. The Department considers NSPS Subpart IIII a technically feasible control technology for the large diesel-fired engines.

(g) Limited Operation
FWA EUs 11, 12, and 13 currently operate under a combined annual limit of less than 600 hours per year to avoid classification as a PSD major modification for NOx. Limiting the operation of emissions units reduces the potential to emit of those units. The Department considers limited operation a technically feasible control technology for the large diesel-fired engines.

(h) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the coal-fired boilers and will not be repeated here. Proper management of the combustion process will result in a reduction of PM-2.5 emissions. The Department considers GCPs a technically feasible control technology for the large diesel-fired engine.

Step 2 - Eliminate Technically Infeasible PM-2.5 Control Technologies for the Large Engines
All control technologies identified are technically feasible to control particulate emissions from the large diesel-fired engines.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Large Diesel-Fired Engines
The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 emissions from the large diesel-fired engines:

(g)	Limited Operation	(94% Control)
(a)	Diesel Particulate Filters	(85% Control)
(h)	Good Combustion Practices	(Less than 40% Control)
(b)	Diesel Oxidation Catalyst	(30% Control)
(e)	Low Ash Diesel	(25% Control)
(c)	Positive Crankcase Ventilation	(10% Control)
(f)	Federal Emission Standards	(Baseline)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright proposes the following as BACT for PM-2.5 emissions from the large diesel-fired engines:

(a) Combined operating limit of 600 hours per year for FWA EUs 11, 12, and 13;

(b) For engines manufactured after the applicability dates of 40 C.F.R. 60 Subpart IIII, BACT is selected as compliance with 40 C.F.R Part 60 Subpart IIII. For older engines, compliance with 40 C.F.R. 63 Subpart ZZZZ is proposed as BACT; and

(c) Combust only ULSD.

Department Evaluation of BACT for PM-2.5 Emissions from the Large Diesel-Fired Engines

The Department reviewed Fort Wainwright's proposal finds that PM-2.5 emissions from the large diesel-fired engines can be controlled by limiting the use of the units during non-emergency operation as well as complying with the applicable federal emission standards.

Step 5 - Selection of PM-2.5 BACT for the Large Diesel-Fired Engines

The Department's finding is that the BACT for PM-2.5 emissions from the large diesel-fired engines is as follows:

(a) Combined operating limit of 600 hours per year for FWA EUs 11, 12, and 13;

(b) Limit EU 8 to 500 hours of operation per year;

(c) Limit non-emergency operation of DU EUs 8, 10, 11, 13, and 15 to no more than 100 hours each per year for maintenance checks and readiness testing;

(d) Combust only ULSD;

(e) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of operation; and

(f) Comply with the numerical BACT emission limits listed in Table 4-6 for PM-2.5.

Table 4-6. Proposed PM-2.5 BACT Limits for Large Diesel-Fired Engines

Location	EU	Year	Description	Size	Status	BACT Limit	Proposed BACT
DU	8	2009	Generator Engine	2,937 hp	Certified Engine	0.15 g/hp-hr	40 CFR 60 Subpart IIII
DU	10	2010	Generator Engine	762 hp	Certified Engine	0.15 g/hp-hr	40 CFR 60 Subpart IIII
DU	11	2010	Generator Engine	762 hp	Certified Engine	0.15 g/hp-hr	40 CFR 60 Subpart IIII
DU	13	2008	Generator Engine	587 hp	Certified Engine	0.15 g/hp-hr	40 CFR 60 Subpart IIII
DU	15	2005	Generator Engine	1,059 hp	AP-42 Table 3.4-1	0.32 g/hp-hr	Good Combustion Practices
FWA	11	2003	Caterpillar 3512	1,206 hp	AP-42 Table 3.4-1	0.32 g/hp-hr	Limit combined operation to 600 hours per 12-month rolling period.
FWA	12	2003	Caterpillar 3512	1,206 hp	AP-42 Table 3.4-1	0.32 g/hp-hr	
FWA	13	2003	Caterpillar 3512	1,206 hp	AP-42 Table 3.4-1	0.32 g/hp-hr	

Table 4-7 lists the proposed PM-2.5 BACT determination for this facility along with those for other diesel-fired engines rated at more than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 4-7. Comparison of PM-2.5 BACT for Large Diesel Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	Large Diesel-Fired Engine	13,266 hp	0.32 g/hp-hr	Positive Crankcase Ventilation Limited Operation
Fort Wainwright	8 Large Diesel-Fired Engines	> 500 hp	0.15 – 0.32 g/hp-hr	Limited Operation Ultra-Low Sulfur Diesel Federal Emission Standards
GVEA North Pole	Large Diesel-Fired Engine	600 hp	0.32 g/hp-hr	Positive Crankcase Ventilation Good Combustion Practices

Facility	Process Description	Capacity	Limitation	Control Method
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp (each)	0.32 g/hp-hr	Limited Operation Good Combustion Practices

4.4 PM-2.5 BACT for the Small Emergency Engines, Fire Pumps, and Generators

Possible PM-2.5 emission control technologies for small engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 17.210, Small Internal Combustion Engines (<500 hp). The search results for diesel-fired engines are summarized in Table 4-8.

Table 4-8. RBLC Summary for PM-2.5 Control for Small Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Federal Emission Standards	3	0.15
Good Combustion Practices	19	0.15 – 0.4
Limited Operation	7	0.15 – 0.17
Low Sulfur Fuel	7	0.15 – 0.3
No Control Specified	14	0.02 – 0.09

RBLC Review
A review of similar units in the RBLC indicates low ash/sulfur diesel, compliance with federal emission standards, limited operation, and good combustion practices are the principle PM-2.5 control technologies installed on small diesel-fired engines. The lowest PM-2.5 emission rate listed in the RBLC is 0.02 g/hp-hr.

Step 1 - Identification of PM-2.5 Control Technology for the Small Diesel-Fired Engines
From research, the Department identified the following technologies as available for control of PM-2.5 emissions from diesel-fired engines rated at less than 500 hp:

(a) Diesel Particulate Filter
The theory behind DPF was discussed in detail in the PM-2.5 BACT for the large diesel-fired engines and will not be repeated here. The Department considers DPF a technically feasible control technology for the small diesel-fired engines.

(b) Diesel Oxidation Catalyst
The theory behind DOC was discussed in detail in the PM-2.5 BACT for the large diesel-fired engines and will not be repeated here. The Department considers DOC a technically feasible control technology for the small diesel-fired engines.

(c) Low Ash Diesel
Residual fuels and crude oil are known to contain ash forming components, while refined fuels are low ash. Fuels containing ash can cause excessive wear to equipment and foul engine components. The Department considers low ash diesel a technically feasible control technology for the small diesel-fired engine.

(d) Federal Emission Standards

The theory behind federal emission standards was discussed in detail in the PM-2.5 BACT for the large diesel-fired engines and will not be repeated here. The Department considers federal emission standards a technically feasible control technology for the small diesel-fired engines.

(e) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation a technically feasible control technology for the small diesel-fired engines.

(f) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the coal-fired boilers and will not be repeated here. Proper management of the combustion process will result in a reduction of PM-2.5 emissions. The Department considers GCPs a technically feasible control technology for the small diesel-fired engines.

Step 2 - Eliminate Technically Infeasible PM-2.5 Control Technologies for the Small Engines
All identified control technologies are technically feasible for the small diesel-fired engines.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Small Diesel-Fired Engines
The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 emissions from the small diesel-fired engines:

(e)	Limited Operation	(94% Control)
(a)	Diesel Particulate Filters	(60% - 90% Control)
(b)	Diesel Oxidation Catalyst	(40% Control)
(f)	Good Combustion Practices	(Less than 40% Control)
(c)	Low Ash/Sulfur Diesel	(25% Control)
(d)	Federal Emission Standards	(Baseline)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright proposes the following as BACT for PM-2.5 emissions from the small diesel-fired engines:

(a) Good Combustion Practices;

(b) For engines manufactured after the applicability dates of 40 C.F.R. 60 Subpart IIII, BACT is proposed as compliance with 40 C.F.R Part 60 Subpart IIII. For older engines, compliance with the 40 C.F.R. 63 Subpart ZZZZ is proposed as BACT; and

(c) Combust only ULSD.

Department Evaluation of BACT for PM-2.5 Emissions from Small Diesel-Fired Engines

The Department reviewed Fort Wainwright's proposal and found that in addition to maintaining good combustion practices, complying with federal requirements, and combusting only ULSD: limiting operation of the small diesel-fired engines during non-emergency operation to no more than 100 hours per year each is BACT for PM-2.5.

Step 5 - Selection of PM-2.5 BACT for the Small Diesel-Fired Engines

The Department's finding is that BACT for PM-2.5 emissions from the small diesel-fired engines is as follows:

(a) Combust only ULSD;

(b) Limit non-emergency operation of DU EUs 9, 12, 14, 16 through 28, 29a, 30, 31a, 32, 33, 34, 35, 36, and FWA EUs 26 through 39 to no more than 100 hours per year each for maintenance checks and readiness testing;

(c) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation; and

(d) Comply with the numerical BACT emission limits listed in Table 4-9 for PM-2.5.

Table 4-9. Proposed PM-2.5 BACT Limits for Small Diesel-Fired Engines

Location	EU	Year	Description	Size	Status	BACT Limit	Proposed BACT
DU	9	1988	Generator Engine	353 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	Limited Operation for Non-Emergency Use (100 hours per year each) Good Combustion Practices Combust ULSD
DU	12	2002	Generator Engine	82 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	14	2008	Generator Engine	320 hp	Certified Engine	0.2 g/kW-hr	
DU	16	2005	Generator Engine	212 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	17	2007	Generator Engine	176 hp	Permit condition 23.1c	0.40 g/hp-hr	
DU	18	2005	Generator Engine	212 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	19	2007	Generator Engine	71 hp	Certified Engine	0.4 g/kW-hr	
DU	20	1976	Generator Engine	35 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	21	2001	Generator Engine	95 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	22	1989	Generator Engine	35 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	23	2003	Generator Engine	155 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	24	1993	Generator Engine	50 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	25	2011	Generator Engine	18 hp	Certified Engine	0.4 g/kW-hr	
DU	26	2003	Generator Engine	68 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	27	2010	Generator Engine	274 hp	Certified Engine	0.2 g/kW-hr	
DU	28	2010	Generator Engine	274 hp	Certified Engine	0.2 g/kW-hr	
DU	30	1952	Lift Pump Engine	75 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	32	1955	Lift Pump Engine	75 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	33	1994	Lift Pump Engine	75 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	34	1995	Well Pump Engine	220 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	35	2009	Well Pump Engine	55 hp	Certified Engine	0.3 g/hp-hr	
DU	36	1995	Well Pump Engine	220 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
DU	29a	2014	Lift Pump Engine	74 hp	Certified Engine	0.03 g/kW-hr	
DU	31a	2014	Lift Pump Engine	74 hp	Certified Engine	0.03 g/kW-hr	
FWA	26	2012	QSB7-G3 NR3	295 hp	Certified Engine	0.02 g/kW-hr	
FWA	27	2009	4024HF285B	67 hp	Certified Engine	0.3 g/kW-hr	
FWA	28	2007	CAT C9 GENSET	398 hp	Certified Engine	0.2 g/kW-hr	
FWA	29	ND	TM30UCM	47 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	30	2007	JW64-UF30	275 hp	Certified Engine	0.2 g/kW-hr	
FWA	31	1994	DDFP-04AT	235 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	32	1994	DDFP-04AT	235 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	33	1994	DDFP-04AT	235 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	

Location	EU	Year	Description	Size	Status	BACT Limit	Proposed BACT
FWA	34	1994	DDFP-04AT	235 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	35	1977	N-855-F	240 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	36	1977	N-855-F	240 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	37	2005	JU4H-UF40	94 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	38	1996	PDFP-06YT	120 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	
FWA	39	1996	PDFP-06YT	120 hp	AP-42, Table 3.3-1	2.20 E-3 lb/hp-hr	

Table 4-10 lists the proposed PM-2.5 BACT determination for this facility along with those for other diesel-fired engines rated at less than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 4-10. Comparison of PM-2.5 BACT for Small Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	41 Small Diesel-Fired Engines	< 500 hp	0.015 – 1.0 g/hp-hr	Good Combustion Practices Limited Operation
UAF	One Small Diesel-Fired Engine	< 500 hp	0.015 – 1.0 g/hp-hr	Good Combustion Practices Limited Operation

4.5 PM-2.5 BACT for the Material Handling

Possible PM-2.5 emission control technologies for material handling were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 99.100 - 190, Fugitive Dust Sources. The search results for material handling units are summarized in Table 4-11.

Table 4-11. RBLC Summary for PM-2.5 Control for Material Handling

Control Technology	Number of Determinations	Emission Limits
Fabric Filter / Baghouse	10	0.005 gr./dscf
Electrostatic Precipitator	3	0.032 lb/MMBtu
Wet Suppressants / Watering	3	29.9 tpy
Enclosures / Minimizing Drop Height	4	0.93 lb/hr

RBLC Review
A review of similar units in the RBLC indicates good operational practices, enclosures, fabric filters, and minimizing drop heights are the principle PM-2.5 control technologies for material handling operations.

Step 1 - Identification of PM-2.5 Control Technology for the Material Handling
From research, the Department identified the following technologies as available for PM-2.5 control of materials handling:

(a) Fabric Filters
The theory behind fabric filters was discussed in detail in the PM-2.5 BACT for the industrial coal-fired boilers and will not be repeated here. The Department considers fabric filters a technically feasible control technology for material handling.

(b) Enclosure
Enclosure structures shelter material from wind entrainment and are used to control particulate emissions. Enclosures can either fully or partially enclose the source and control efficiency is dependent on the level of enclosure.

(c) Wet and Dry Electrostatic Precipitators
The theory behind ESPs was discussed in detail in the PM-2.5 BACT for the industrial coal-fired boilers and will not be repeated here. The Department considers ESPs a technically feasible control technology for material handling.

(d) Wet Scrubbers
The theory behind wet scrubbers was discussed in detail in the PM-2.5 BACT for the industrial coal-fired boilers and will not be repeated here. The Department considers wet scrubbers a technically feasible control technology for material handling.

(e) Mechanical Collectors (Cyclones)
The theory behind cyclones was discussed in detail in the PM-2.5 BACT for the industrial coal-fired boilers and will not be repeated here. The Department considers cyclones a technically feasible control technology for material handling.

(f) Suppressants
The use of dust suppression to control particulate matter can be effective for stockpiles and transfer points exposed to the open air. Applying water or a chemical suppressant can bind the materials together into larger particles which reduces the ability to become entrained in the air either from wind or material handling activities. The Department considers the use of suppressants a technically feasible control technology for all of the material handling units.

(g) Wind Screens
A wind screen is similar to a solid fence which is used to lower wind velocities near stockpiles and material handling sites. As wind speeds increase, so do the fugitive emissions from the stockpiles, conveyors, and transfer points. The use of wind screens is appropriate for materials not already located in enclosures. Due to all of the material handling units being operated in enclosures the Department does not consider wind screens a technically feasible control technology for the material handling units.

(h) Vents/Closed System Vents/Negative Pressure Vents
Vents can control fugitive emissions by collecting fugitive emissions from enclosed loading, unloading, and transfer points and then venting emissions to the atmosphere or back into other equipment such as a storage silo. Other vent control designs include enclosing emission units and operating under a negative pressure. The Department considers vents to be a technically feasible control technology for the material handling units.

Step 2 - Eliminate Technically Infeasible PM-2.5 Controls for the Material Handling

All of the identified control technologies are technically feasible for material handling.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Material Handling
The following control technologies have been identified and ranked for control of particulates from the material handling equipment.

(a)	Fabric Filters	(50 - 99% Control)
(b)	Enclosures	(50 - 99% Control)
(d)	Wet Scrubber	(50% - 99% Control)
(c)	Electrostatic Precipitator	(>90% Control)
(e)	Cyclone	(20% -70% Control)
(f)	Suppressants	(less than 90% Control)
(h)	Vents	(less than 90% Control)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright proposes the following as BACT for PM-2.5 emissions from material handling based on a combination of manufacturing design and loading techniques:

(a) PM-2.5 emissions from the South Coal Handling Dust Collector (EU 7a) shall not exceed 0.0025 gr/dscf and shall be controlled by enclosed emission points and by following manufacturer's recommendations for operations and maintenance.

(b) PM-2.5 emissions from the South Underbunker, Fly Ash, and Bottom Ash Dust Collectors (EUs 7b, 7c, 51a, and 51b) shall not exceed 0.02 gr/dscf and shall be controlled by enclosed emission points and by following manufacturer's recommendations for operations and maintenance.

(c) PM-2.5 emissions from the North Coal Handling Dust Collector (EU 7c) shall not exceed 0.02 gr/dscf and shall be limited to no more than 200 hours per year.

(d) Initial compliance with the PM-2.5 emission limits, except the emission limit for EU 52, will be demonstrated by conducting a performance test to obtain an emission rate.

(e) PM-2.5 emissions from the Emergency Coal Storage Pile and Operations (EU 52) shall not exceed 1.42 tpy and shall be controlled with chemical stabilizers, wind fencing, covered haul vehicles, watering, and wind awareness. These procedures are identified in the September 2003 Fort Wainwright Dust Control Plan, prepared by the United States Army Center for Health Promotion and Preventive Medicine Alaskan Field Office in Conjunction with Oak Ridge Institute for Science and Education.

Step 5 - Selection of PM-2.5 BACT for the Material Handling Equipment
The Department's finding is that BACT for PM-2.5 emissions from the material handling equipment is as follows:

(a) PM-2.5 emissions from the material handling equipment EUs 7a – 7c, 51a, and 51b shall be controlled by operating and maintaining fabric filters at all times the units are in operation;

(b) Comply with the numerical BACT emission limits listed in Table 4-12 for PM-2.5;

(c) PM-2.5 emissions from DU EU 52 shall not exceed 1.42 tpy. Continuous compliance with the PM-2.5 emissions limit shall be demonstrated by complying with the fugitive dust

control plan identified in the applicable operating permit issued to the source in accordance with 18 AAC 50 and AS 46.14; and

(d) Initial compliance with the PM-2.5 emission rates for the material handling units, except EU 52, shall be demonstrated with a performance test to obtain an emission rate.

Table 4-12. PM-2.5 BACT Control Technologies Proposed for Material Handling

EU ID	Description	Current Control	BACT Limit	Proposed BACT Control
7a	South Coal Handling Dust Collector	Partial Enclosure and Dust Collection	0.0025 gr/dscf	Enclosed emission points and follow manufacturer recommendations for operations and maintenance
7b	South Underbunker Dust Collector	Partial Enclosure and Dust Collection	0.02 gr/dscf	Enclosed emission points and follow manufacturer recommendations for operations and maintenance
7c	North Coal Handling Dust Collector	Partial Enclosure and Dust Collection	0.02 gr/dscf	Limited Operation – This source serves as backup to EU 7a and operates less than 200 hours each year
52	Emergency Coal Storage Pile and Operations	Follow Fugitive Dust Control Plan	Dust Control Plan[20]	Chemical Stabilizers, Wind Fencing, Covered Haul Vehicles, Watering, and Wind Awareness
51a	Fly Ash Dust Collector	Partial Enclosure and Dust Collection	0.02 gr/dscf	Enclosed emission points and follow manufacturer recommendations for operations and maintenance
51b	Bottom Ash Dust Collector	Partial Enclosure and Dust Collection	0.02 gr/dscf	Enclosed emission points and follow manufacturer recommendations for operations and maintenance

5. BACT DETERMINATION FOR SO_2

The Department based its SO_2 assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by GVEA for the North Pole Power Plant and Zehnder Facility, Aurora for the Chena Power Plant, US Army for Fort Wainwright, and UAF for the Combined Heat and Power Plant.

5.1 SO_2 BACT for the Industrial Coal-Fired Boilers

Possible SO_2 emission control technologies for coal-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.110, Coal Combustion in Industrial Size Boilers and Furnaces. The search results for the coal-fired boilers are summarized in Table 5-1.

Table 5-1. RBLC Summary of SO_2 Control for Industrial Coal-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Flue Gas Desulfurization / Scrubber / Spray Dryer	10	0.06 – 0.12
Limestone Injection	10	0.055 – 0.114
Low Sulfur Coal	4	0.06 – 1.2

[20] If technological or economic limitations in the application of a measurement methodology to a particular emission unit would make an emission limit infeasible, a design, equipment, work practice, operational standard or combination of thereof, may be prescribed.

RBLC Review
A review of similar units in the RBLC indicates flue gas desulfurization, limestone injection, and low sulfur coal are the principle SO_2 control technologies installed on industrial coal-fired boilers. The lowest SO_2 emission rate in the RBLC is 0.055 lb/MMBtu.

Step 1- Identification of SO_2 Control Technology for the Coal-Fired Boilers
From research, the Department identified the following technologies as available for SO_2 control of industrial coal-fired boilers:

(a) Wet Scrubbers
Post combustion flue gas desulfurization techniques can remove SO_2 formed during combustion by using an alkaline reagent to absorb SO_2 in the flue gas. Flue gasses can be treated using wet, dry, or semi-dry desulfurization processes. In the wet scrubbing system, flue gas is contacted with a solution or slurry of alkaline material in a vessel providing a relatively long residence time. The SO_2 in the flue reacts with the alkali solution or slurry by adsorption and/or absorption mechanisms to form liquid-phase salts. These salts are dried to about one percent free moisture by the heat in the flue gas. These solids are entrained in the flue gas and carried from the dryer to a PM collection device, such as a baghouse.

The lime and limestone wet scrubbing process uses a slurry of calcium oxide or limestone to absorb SO_2 in a wet scrubber. Control efficiencies in excess of 91 percent for lime and 94 percent for limestone over extended periods are possible. Sodium scrubbing processes generally employ a wet scrubbing solution of sodium hydroxide or sodium carbonate to absorb SO_2 from the flue gas. Sodium scrubbers are generally limited to smaller sources because of high reagent costs and can have SO_2 removal efficiencies of up to 96.2 percent. The double or dual alkali system uses a clear sodium alkali solution for SO_2 removal followed by a regeneration step using lime or limestone to recover the sodium alkali and produce a calcium sulfite and sulfate sludge. SO_2 removal efficiencies of 90 to 96 percent are possible. The Department considers flue gas desulfurization with a wet scrubber a technically feasible control technology for the industrial coal-fired boilers.

(b) Spray Dry Absorbers (SDA)
In SDA systems, an aqueous sorbent slurry with a higher sorbent ratio than that of a wet scrubber is injected into the hot flue gases. As the slurry mixes with the flue gas, the water is evaporated and the process forms a dry waste which is collected in a baghouse or electrostatic precipitator. The Department considers flue gas desulfurization with an SDA system a technically feasible control technology for the industrial coal-fired boilers.

(c) Dry Sorbent Injection (DSI)
Dry sorbent injection systems (spray dry scrubbers) pneumatically inject a powdered sorbent directly into the furnace, the economizer, or the downstream ductwork depending on the temperature and the type of sorbent utilized. The dry waste is removed using a baghouse or electrostatic precipitator. Spray drying technology is less complex mechanically, and no more complex chemically, than wet scrubbing systems. The main

advantages of the spray dryer is that this technology avoids two problems associated with wet scrubbing, corrosion and liquid waste treatment. Spray dry scrubbers are mostly used for small to medium capacity boilers and are preferable for retrofits. The Department considers flue gas desulfurization with a dry scrubber a technically feasible control technology for the industrial coal-fired boilers.

(d) Low Sulfur Coal
Fort Wainwright purchases coal from the Usibelli Coal Mine located in Healy, Alaska. This coal mine is located 115 miles south of Fairbanks. The coal mined at Usibelli is sub-bituminous coal and has a relatively low sulfur content with guarantees of less than 0.4 percent by weight. Usibelli Coal Data Sheets indicate a range of 0.08 to 0.28 percent Gross As Received (GAR) percent Sulfur (%S). According to the U.S. Geological Survey, coal with less than one percent sulfur is classified as low sulfur coal. The Department considers the use of low sulfur coal a feasible control technology for the industrial coal-fired boilers.

(e) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the industrial coal-fired boilers and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the industrial coal-fired boilers.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for Coal-Fired Boilers
All identified control devices are technically feasible for the industrial coal-fired boilers.

Step 3 - Rank the Remaining SO_2 Control Technologies for Industrial Coal-Fired Boilers
The following control technologies have been identified and ranked by efficiency for control of SO_2 emissions from the industrial coal-fired boilers:

(a)	Wet Scrubbers	(99% Control)
(b)	Spray Dry Absorbers	(90% Control)
(c)	Dry Sorbent Injection (Duct Sorbent Injection)	(50 – 80% Control)
(d)	Low Sulfur Coal	(30% Control)
(e)	Good Combustion Practices	(Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright provided an economic analysis of the installation of wet and dry scrubber systems. A summary of the analysis is shown below:

Table 5-2. Fort Wainwright Economic Analysis for Technically Feasible SO_2 Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber	1,767	1,749	???	???	6,900 - 13,800

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
Spray-Dry Scrubber	1,767	1,590	???	???	5,200 - 6,200
Dry Sorbent Injection[21]	1,767	1,414	6,191,696	6,384,196	4,516 - 5,968
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

Fort Wainwright contends that the economic analysis indicates the level of SO_2 reduction does not justify the use of wet scrubbers, semi-dry scrubbers, or dry scrubber systems (dry-sorbent injection) for the coal-fired boilers based on the excessive cost per ton of SO_2 removed per year.

Fort Wainwright proposes the following as BACT for SO_2 emissions from the coal-fired boilers:

(a) SO_2 emissions from the operation of the coal-fired boilers will be controlled by limited operation, good combustion practices, and low sulfur fuel at all times the boilers are in operation.

(b) SO_2 emissions from the coal-fired boilers will be controlled by burning low sulfur coal at all times the boilers are in operation.

(c) SO_2 emissions from the coal-fired boilers will not exceed 0.49 lb/MMBtu.

(d) SO_2 emissions from the coal-fired boilers will be controlled by limiting the allowable coal combustion to no more than 300,000 tons per year.

(e) Initial compliance with the proposed SO_2 emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

Department Evaluation of BACT for SO_2 Emissions from the Industrial Coal-Fired Boilers
The Department revised the cost analysis provided for the installation of wet scrubbers, semi-dry scrubbers (spray dry absorbers), and dry scrubbers (dry sorbent injection) using a potential to emit of 1,168 tpy for the six coal-fired boilers combined (calculated using the existing permit limit of 336,000 tons of coal per year combined), a baseline emission rate of 0.46 lb SO_2/MMBtu,[22] a retrofit factor of 1.5 for difficult retrofits, a SO_2 removal efficiency of 99%, 90% and 80% for wet scrubbers, spray dry absorbers and dry sorbent injection respectively, an interest rate of 5.5% (current bank prime interest rate), and a 15 year equipment life. A summary of the analysis is shown below:

Table 5-3. Department Economic Analysis for Technically Feasible SO_2 Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber	1,168	1,157	138,118,131	23,913,899	20,673
Spray Dry Absorbers	1,168	1,052	125,929,192	22,305,559	21,211

[21] Calculated using Amerair Industries Proposal for 80% removal of SO_2 emissions.

[22] Calculated assuming a 0.2% sulfur content by weight (typical gross as received) and a higher heating value of 7,560 Btu/lb for Healy coal (average of gross as received range) http://www.usibelli.com/coal/data-sheet, and AP-42 Table 1.1-3 emission factors for spreader stoker boilers combusting sub-bituminous coal.

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
Dry Sorbent Injection	1,168	935	15,279,601	9,655,624	10,329
Capital Recovery Factor = 0.0996 (5.5% interest rate for a 15 year equipment life)					

The Department's economic analysis indicates the level of SO_2 reduction justifies the use of dry sorbent injection as BACT for the coal-fired boilers located in the Serious PM-2.5 nonattainment area.

Step 5 - Selection of SO_2 BACT for the Industrial Coal-Fired Boilers
The Department's finding is that BACT for SO_2 emissions from the coal-fired boilers is as follows:

(a) SO_2 emissions from DU EUs 1 through 6 shall be controlled by operating and maintaining dry sorbent injection at all times the units are in operation;

(b) SO_2 emissions from DU EUs 1 through 6 shall not exceed 0.10 lb/MMBtu[23] averaged over a 3-hour period;

(c) Limit the combined coal combustion in DU EUs 1 through 6 to no more than 336,000 tons per year.

(d) Initial compliance with the SO_2 emission rate for the coal-fired boilers will be demonstrated by conducting a performance test to obtain an emission rate.

Table 5-4 lists the proposed SO_2 BACT determination for this facility along with those for other coal-fired boilers in the Serious PM-2.5 nonattainment area.

Table 5-4. Comparison of SO_2 BACT for Coal-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	6 Coal-Fired Boilers	1380 MMBtu/hr (combined)	0.10 lb/MMBtu[23]	Dry Sorbent Injection Limited Operation Low Sulfur Coal
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.10 lb/MMBtu	Dry Sorbent Injection Limestone Injection Low Sulfur Coal
Chena	4 Coal-Fired Boilers	497 MMBtu/hr (combined)	0.10 lb/MMBtu	Dry Sorbent Injection Low Sulfur Coal

[23] BACT limit selected after evaluating existing emission limits in the RBLC database for coal-fired boilers, taking into account previous source test data from coal-fired boilers in Alaska and actual emissions data from other sources employing similar types of controls, using site specific vendor quotes provided by Amerair Industries, and in-line with EPA's pollution control Fact Sheets while keeping in mind that BACT limits must be achievable at all times.

5.2 SO_2 BACT for the Diesel-Fired Boilers

Possible SO_2 emission control technologies for diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.220, Commercial/Institutional Size Boilers (<100 MMBtu/hr). The search results for diesel-fired boilers are summarized in Table 5-5.

Table 5-5. RBLC Summary of SO_2 Control for Diesel-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Low Sulfur Fuel	5	0.0036 – 0.0094
Good Combustion Practices	4	0.0005
No Control Specified	5	0.0005

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and combustion of low sulfur fuel are the principle SO_2 control technologies installed on diesel-fired boilers. The lowest SO_2 emission rate listed in the RBLC is 0.0005 lb/MMBtu.

Step 1 - Identification of SO_2 Control Technology for the Diesel-Fired Boilers
From research, the Department identified the following technologies as available for control of SO_2 emissions from diesel-fired boilers:

(a) Ultra-Low Sulfur Diesel
ULSD has a fuel sulfur content of 0.0015 percent sulfur by weight or less. Using ULSD would reduce SO_2 emissions because the diesel-fired boilers are combusting standard diesel that has a sulfur content of up to 0.5 percent sulfur by weight. Switching to ULSD could control 99 percent of SO_2 emissions from the diesel-fired boilers. The Department considers ULSD a technically feasible control technology for the diesel-fired boilers.

(b) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation a technically feasible control technology for the diesel-fired boilers.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the coal-fired boilers and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the diesel-fired boilers.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for the Diesel-Fired Boilers
All identified control technologies are technically feasible for the diesel-fired boilers.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Diesel-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from the diesel-fired boilers:

(a) Ultra Low Sulfur Diesel (99% Control)
(b) Limited Operation (94% Control)
(c) Good Combustion Practices (Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright proposes the following as BACT for SO_2 emissions from the diesel-fired boilers:

(a) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of operation;

(b) Combined operating limit of 600 hours per year for FWA EUs 8, 9, and 10; and

(c) Combust only ULSD.

Department Evaluation of BACT for SO_2 Emissions from Diesel-Fired Boilers

The Department reviewed Fort Wainwright's proposal and finds that the 27 diesel fired boilers have a combined PTE of less than ten tpy for SO_2 based on non-emergency operation of 500 hours per year. At ten tpy, the cost effectiveness in terms of dollars per ton for add-on pollution control for these units is economically infeasible.

Step 5 - Selection of SO_2 BACT for the Diesel-Fired Boilers

The Department's finding is that BACT for SO_2 emissions from the diesel-fired boilers is as follows:

(a) SO_2 emissions from the diesel-fired boilers shall be controlled by only combusting ULSD, with the exception of the waste fuel boilers;

(b) Combined operating limit of 600 hours per year for FWA EUs 8, 9, and 10;

(c) Limit non-emergency operation of the 27 diesel fired boilers, with the exception of the waste-fuel boilers, to no more than 500 hours per year, for maintenance checks and readiness testing; and

(d) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of operation.

Table 5-6 lists the proposed SO_2 BACT determination for this facility along with those for other diesel-fired boilers rated at less than 100 MMBtu/hr in the Serious PM-2.5 nonattainment area.

Table 5-6. Comparison of SO_2 BACT for the Diesel-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Limited Operation Good Combustion Practices Ultra-Low Sulfur Diesel
	Waste Fuel-Fired Boilers		0.5 % S by weight	Good Combustion Practices
UAF	3 Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel

Facility	Process Description	Capacity	Limitation	Control Method
GVEA Zehnder	2 Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel

5.3 SO_2 BACT for the Large Diesel-Fired Engines, Fire Pumps, and Generators

Possible SO_2 emission control technologies for large engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.100 to 17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 5-7.

Table 5-7. RBLC Summary for SO_2 Control for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Low Sulfur Diesel	27	0.005 – 0.02
Federal Emission Standards	6	0.001 – 0.005
Limited Operation	6	0.005 – 0.006
Good Combustion Practices	3	None Specified
No Control Specified	11	0.005 – 0.008

RBLC Review
A review of similar units in the RBLC indicates combustion of low sulfur fuel, limited operation, good combustion practices, and compliance with the federal emission standards are the principle SO_2 control technologies installed on large diesel-fired engines. The lowest SO_2 emission rate listed in the RBLC is 0.001 g/hp-hr.

Step 1 - Identification of SO_2 Control Technology for the Large Diesel-Fired Engines
From research, the Department identified the following technologies as available for control of SO_2 emissions from diesel-fired engines rated at 500 hp or greater:

(a) Ultra-Low Sulfur Diesel
The theory of ULSD was discussed in detail in the SO_2 BACT for the diesel-fired boilers and will not be repeated here. The Department considers ULSD a technically feasible control technology for the large diesel-fired engines.

(b) Federal Emission Standards
The theory of federal emission standards was discussed in detail in the NOx BACT for the large diesel-fired engines and will not be repeated here. The Department considers meeting the technology based NSPS of Subpart IIII as a technically feasible control technology for the large diesel-fired engines.

(c) Limited Operation
FWA EUs 11, 12, and 13 currently operate under a combined annual limit of less than 600 hours per year to avoid classification as a PSD major modification for NOx. Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation a technically feasible control technology for the large diesel-fired engines.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the coal-fired boilers and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the large diesel-fired engines.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for the Large Engines
All identified control technologies are technically feasible for the large diesel-fired engines.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Large Diesel-Fired Engines
The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from the large diesel-fired engines.

(a)	Ultra Low Sulfur Diesel	(99% Control)
(c)	Limited Operation	(94% Control)
(d)	Good Combustion Practices	(Less than 40% Control)
(b)	Federal Emission Standards	(Baseline)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright proposes the following as BACT for SO_2 emissions from the large diesel-fired engines:

(a) Combined operating limit of 600 hours per year for FWA EUs 11, 12, and 13; and

(b) SO_2 emissions from the operation of the large diesel-fired engines shall be controlled with combustion of ultra-low sulfur diesel.

Department Evaluation of BACT for SO_2 Emissions from the Large Diesel-Fired Engines

The Department reviewed Fort Wainwright's proposal and finds that SO_2 emissions from the large diesel-fired engines can additionally be controlled by limiting the use of the units during non-emergency operation.

Step 5 - Selection of SO_2 BACT for the Large Diesel-Fired Engines
The Department's finding is that BACT for SO_2 emissions from the large diesel-fired engines is as follows:

(a) SO_2 emissions from DU EUs 8, 10, 11, 13, and 15 and FWA EUs 11, 12, and 13 shall be controlled by only combusting ULSD;

(b) Limit EU 8 to 500 hours per year;

(c) Combined operating limit of 600 hours per year for FWA EUs 11, 12, and 13;

(d) Limit non-emergency operation of DU EUs 8, 10, 11, 13, and 15 to no more than 100 hours per year, for maintenance checks and readiness testing; and

(e) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of operation.

Table 5-8 lists the proposed SO_2 BACT determination for this facility along with those for other diesel-fired engines rated at more than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 5-8. Comparison of SO_2 BACT for Large Diesel-Fired Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	8 Large Diesel-Fired Engines	> 500 hp	15 ppmw S in fuel	Limited Operation Good Combustion Practices Ultra-Low Sulfur Diesel
UAF	Large Diesel-Fired Engine	13,266 hp	15 ppmw S in fuel	Limited Operation Good Combustion Practices Ultra-Low Sulfur Diesel
GVEA North Pole	Large Diesel-Fired Engine	600 hp	500 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel

5.4 SO_2 BACT for the Small Emergency Engines, Fire Pumps, and Generators

Possible SO_2 emission control technologies for small engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 17.210, Small Internal Combustion Engines (<500 hp). The search results for small diesel-fired engines are summarized in Table 5-9.

Table 5-9. RBLC Summary for SO_2 Control for Small Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Low Sulfur Diesel	6	0.005 – 0.02
No Control Specified	3	0.005

RBLC Review
A review of similar units in the RBLC indicates combustion of low sulfur fuel is the principle SO_2 control technology for small diesel-fired engines. The lowest SO_2 emission rate listed in the RBLC is 0.005 g/hp-hr.

Step 1 - Identification of SO_2 Control Technology for the Small Diesel-Fired Engines
From research, the Department identified the following technologies as available for control of SO_2 emissions from diesel-fired engines rated at less than 500 hp:

(a) Ultra-Low Sulfur Diesel
The theory of ULSD was discussed in detail in the SO_2 BACT for the small diesel-fired boilers and will not be repeated here. The Department considers ULSD a technically feasible control technology for the small diesel-fired engines.

(b) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. The

Department considers limited operation a technically feasible control technology for the small diesel-fired engines.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the coal-fired boilers and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the small diesel-fired engines.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for the Small Engines
All identified control technologies are technically feasible for the small diesel-fired engines.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Small Diesel-Fired Engines
The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from the small diesel-fired engines.

(a) Ultra Low Sulfur Diesel (99% Control)
(b) Limited Operation (94% Control)
(c) Good Combustion Practices (Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

Fort Wainwright BACT Proposal

Fort Wainwright proposes the following as BACT for SO_2 emissions from the small diesel-fired engines:

(a) Good Combustion Practices;

(b) Combust only ULSD.

Department Evaluation of BACT for SO_2 Emissions from Small Diesel-Fired Engines

The Department reviewed Fort Wainwright's proposal and found that in addition to maintaining good combustion practices and combusting only ULSD, limiting operation of the small diesel-fired engines during non-emergency operation to no more than 100 hours per year each is BACT for SO_2.

Step 5 - Selection of SO_2 BACT for the Small Diesel-Fired Engines
The Department's finding is that BACT for SO_2 emissions from the small diesel-fired engines is as follows:

(a) Limit non-emergency operation of DU EUs 9, 12, 14, 16 through 28, 29a, 30, 31a, 32, 33, 34, 35, 36, and FWA EUs 26 through 39 to no more than 100 hours per year each for maintenance checks and readiness testing;

(b) Combust only ULSD; and

(c) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of operation.

Table 5-10 lists the proposed SO_2 BACT determination for this facility along with those for other diesel-fired engines rated at less than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 5-10. Comparison of SO_2 BACT for Small Diesel-Fired Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	41 Small Diesel-Fired Engines	< 500 hp	15 ppmw S in fuel	Limited Operation Ultra-Low Sulfur Diesel Good Combustion Practices
UAF	One Small Diesel-Fired Engine	< 500 hp	15 ppmw S in fuel	Limited Operation Ultra-Low Sulfur Diesel

6. BACT DETERMINATION SUMMARY

Table 6-1. Proposed NOx BACT Limits

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
DU 1	Six Coal Fired Boiler 3	230 MMBtu/hr	0.06 lb/MMBtu	Selective Catalytic Reduction
DU 2	Six Coal Fired Boiler 4	230 MMBtu/hr	0.06 lb/MMBtu	
DU 3	Six Coal Fired Boiler 5	230 MMBtu/hr	0.06 lb/MMBtu	
DU 4	Six Coal Fired Boiler 6	230 MMBtu/hr	0.06 lb/MMBtu	
DU 5	Six Coal Fired Boiler 7	230 MMBtu/hr	0.06 lb/MMBtu	
DU 6	Six Coal Fired Boiler 8	230 MMBtu/hr	0.06 lb/MMBtu	
FWA 8	Backup Diesel-Fired Boiler 1	19 MMBtu/hr	0.15 lb/MMBtu	Good Combustion Practices Limited Operation (600 hours/year combined)
FWA 9	Backup Diesel-Fired Boiler 2	19 MMBtu/hr	0.15 lb/ MMBtu	
FWA 10	Backup Diesel-Fired Boiler 3	19 MMBtu/hr	0.15 lb/ MMBtu	
N/A	Diesel-Fired Boilers (24)	Varies	0.15 lb/ MMBtu	Good Combustion Practices Limited Operation (500 hours/year each, for non-emergency operation)
DU 8	Generator Engine	2,937 hp	4.8 g/hp-hr	Good Combustion Practices Limited Operation (100 hours/year each, for non-emergency operation)
DU 10	Generator Engine	762 hp	4.8 g/hp-hr	
DU 11	Generator Engine	762 hp	4.8 g/hp-hr	
DU 13	Generator Engine	587 hp	3.0 g/hp-hr	
DU 15	Generator Engine	1,059 hp	5.75 g/hp-hr	
FWA 11	Caterpillar 3512	1,206 hp	10.9 g/hp-hr	Good Combustion Practices Limited Operation (600 hours/year combined)
FWA 12	Caterpillar 3512	1,206 hp	10.9 g/hp-hr	
FWA 13	Caterpillar 3512	1,206 hp	10.9 g/hp-hr	
DU 9	Generator Engine	353 hp	0.031 lb/hp-hr	Good Combustion Practices Limited Operation (100 hours/year each, for non-emergency operation)
DU 12	Generator Engine	82 hp	0.031 lb/hp-hr	
DU 14	Generator Engine	320 hp	4.0 g/kW-hr	
DU 16	Generator Engine	212 hp	0.031 lb/hp-hr	
DU 17	Generator Engine	176 hp	6.9 lb/hp-hr	
DU 18	Generator Engine	212 hp	0.031 lb/hp-hr	
DU 19	Generator Engine	71 hp	7.5 g/kW-hr	
DU 20	Generator Engine	35 hp	0.031 lb/hp-hr	

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
DU 21	Generator Engine	95 hp	0.031 lb/hp-hr	Good Combustion Practices Limited Operation (100 hours/year each, for non-emergency operation)
DU 22	Generator Engine	35 hp	0.031 lb/hp-hr	
DU 23	Generator Engine	155 hp	0.031 lb/hp-hr	
DU 24	Generator Engine	50 hp	0.031 lb/hp-hr	
DU 25	Generator Engine	18 hp	7.5 g/kW-hr	
DU 26	Generator Engine	68 hp	0.031 lb/hp-hr	
DU 27	Generator Engine	274 hp	4.0 g/kW-hr	
DU 28	Generator Engine	274 hp	4.0 g/kW-hr	
DU 30	Lift Pump Engine	75 hp	0.031 lb/hp-hr	
DU 32	Lift Pump Engine	75 hp	0.031 lb/hp-hr	
DU 33	Lift Pump Engine	75 hp	0.031 lb/hp-hr	
DU 34	Well Pump Engine	220 hp	0.031 lb/hp-hr	
DU 35	Well Pump Engine	55 hp	4.7 g/hp-hr	
DU 36	Well Pump Engine	220 hp	0.031 lb/hp-hr	
DU 29a	Lift Pump Engine	74 hp	4.7 g/kW-hr	
DU 31a	Lift Pump Engine	74 hp	4.7 g/kW-hr	
FWA 26	QSB7-G3 NR3	295 hp	4.0 g/kW-hr	
FWA 27	4024HF285B	67 hp	4.7 g/kW-hr	
FWA 28	CAT C9 GENSET	398 hp	4.0 g/kW-hr	
FWA 29	TM30UCM	47 hp	0.031 lb/hp-hr	
FWA 30	JW64-UF30	275 hp	4.0 g/kW-hr	
FWA 31	DDFP-04AT	235 hp	0.031 lb/hp-hr	
FWA 32	DDFP-04AT	235 hp	0.031 lb/hp-hr	
FWA 33	DDFP-04AT	235 hp	0.031 lb/hp-hr	
FWA 34	DDFP-04AT	235 hp	0.031 lb/hp-hr	
FWA 35	N-855-F	240 hp	0.031 lb/hp-hr	
FWA 36	N-855-F	240 hp	0.031 lb/hp-hr	
FWA 37	JU4H-UF40	94 hp	0.031 lb/hp-hr	
FWA 38	PDFP-06YT	120 hp	0.031 lb/hp-hr	
FWA 39	PDFP-06YT	120 hp	0.031 lb/hp-hr	

Table 6-2. Proposed PM-2.5 BACT Limits

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
DU 1	Six Coal Fired Boiler 3	230 MMBtu/hr	0.006 lb/MMBtu	Full stream baghouse
DU 2	Six Coal Fired Boiler 4	230 MMBtu/hr	0.006 lb/MMBtu	
DU 3	Six Coal Fired Boiler 5	230 MMBtu/hr	0.006 lb/MMBtu	
DU 4	Six Coal Fired Boiler 6	230 MMBtu/hr	0.006 lb/MMBtu	
DU 5	Six Coal Fired Boiler 7	230 MMBtu/hr	0.006 lb/MMBtu	
DU 6	Six Coal Fired Boiler 8	230 MMBtu/hr	0.006 lb/MMBtu	
FWA 8	Backup Diesel-Fired Boiler 1	19 MMBtu/hr	0.012 lb/MMBtu	Good Combustion Practices Limited Operation (600 hours/year combined) Combust ULSD
FWA 9	Backup Diesel-Fired Boiler 2	19 MMBtu/hr	0.012 lb/MMBtu	
FWA 10	Backup Diesel-Fired Boiler 3	19 MMBtu/hr	0.012 lb/MMBtu	
N/A	Diesel-Fired Boilers	Varies	0.012 lb/MMBtu	Good Combustion Practices Limited Operation (500 hours/year each, for non-emergency operation) Combust ULSD
DU 8	Generator Engine	2,937 hp	0.15 g/hp-hr	40 CFR 60 Subpart IIII Combust ULSD Good Combustion Practices Limited Operation (100 hours/year each, for non-emergency operation)
DU 10	Generator Engine	762 hp	0.15 g/hp-hr	
DU 11	Generator Engine	762 hp	0.15 g/hp-hr	
DU 13	Generator Engine	587 hp	0.15 g/hp-hr	
DU 15	Generator Engine	1,059 hp	0.32 g/hp-hr	Limited Operation (100 hours/year, for non-emergency operation) Good Combustion Practices Combust ULSD
FWA 11	Caterpillar 3512	1,206 hp	0.32 g/hp-hr	Limit Operation (600 hours/year combined) Combust ULSD Good Combustion Practices
FWA 12	Caterpillar 3512	1,206 hp	0.32 g/hp-hr	
FWA 13	Caterpillar 3512	1,206 hp	0.32 g/hp-hr	

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
DU 9	Generator Engine	353 hp	2.20 E-3 lb/hp-hr	Limited Operation (100 hours/year each, for non-emergency operation); Good Combustion Practices; Combust ULSD
DU 12	Generator Engine	82 hp	2.20 E-3 lb/hp-hr	
DU 14	Generator Engine	320 hp	0.2 g/kW-hr	
DU 16	Generator Engine	212 hp	2.20 E-3 lb/hp-hr	
DU 17	Generator Engine	176 hp	0.40 g/hp-hr	
DU 18	Generator Engine	212 hp	2.20 E-3 lb/hp-hr	
DU 19	Generator Engine	71 hp	0.4 g/kW-hr	
DU 20	Generator Engine	35 hp	2.20 E-3 lb/hp-hr	
DU 21	Generator Engine	95 hp	2.20 E-3 lb/hp-hr	
DU 22	Generator Engine	35 hp	2.20 E-3 lb/hp-hr	
DU 23	Generator Engine	155 hp	2.20 E-3 lb/hp-hr	
DU 24	Generator Engine	50 hp	2.20 E-3 lb/hp-hr	
DU 25	Generator Engine	18 hp	0.4 g/kW-hr	
DU 26	Generator Engine	68 hp	2.20 E-3 lb/hp-hr	
DU 27	Generator Engine	274 hp	0.2 g/kW-hr	
DU 28	Generator Engine	274 hp	0.2 g/kW-hr	
DU 30	Lift Pump Engine	75 hp	2.20 E-3 lb/hp-hr	
DU 32	Lift Pump Engine	75 hp	2.20 E-3 lb/hp-hr	
DU 33	Lift Pump Engine	75 hp	2.20 E-3 lb/hp-hr	
DU 34	Well Pump Engine	220 hp	2.20 E-3 lb/hp-hr	
DU 35	Well Pump Engine	55 hp	0.3 g/hp-hr	
DU 36	Well Pump Engine	220 hp	2.20 E-3 lb/hp-hr	
DU 29a	Lift Pump Engine	74 hp	0.03 g/kW-hr	
DU 31a	Lift Pump Engine	74 hp	0.03 g/kW-hr	
FWA 26	QSB7-G3 NR3	295 hp	0.02 g/kW-hr	
FWA 27	4024HF285B	67 hp	0.3 g/kW-hr	
FWA 28	CAT C9 GENSET	398 hp	0.2 g/kW-hr	
FWA 29	TM30UCM	47 hp	2.20 E-3 lb/hp-hr	
FWA 30	JW64-UF30	275 hp	0.2 g/kW-hr	
FWA 31	DDFP-04AT	235 hp	2.20 E-3 lb/hp-hr	
FWA 32	DDFP-04AT	235 hp	2.20 E-3 lb/hp-hr	

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
FWA 33	DDFP-04AT	235 hp	2.20 E-3 lb/hp-hr	Limited Operation (100 hours/year each, for non-emergency operation); Good Combustion Practices; Combust ULSD
FWA 34	DDFP-04AT	235 hp	2.20 E-3 lb/hp-hr	
FWA 35	N-855-F	240 hp	2.20 E-3 lb/hp-hr	
FWA 36	N-855-F	240 hp	2.20 E-3 lb/hp-hr	
FWA 37	JU4H-UF40	94 hp	2.20 E-3 lb/hp-hr	
FWA 38	PDFP-06YT	120 hp	2.20 E-3 lb/hp-hr	
FWA 39	PDFP-06YT	120 hp	2.20 E-3 lb/hp-hr	

Table 6-3. Proposed PM-2.5 BACT Limits for Material Handling Equipment

EU ID	Description	Proposed BACT Limit	Proposed BACT Control
7a	South Coal Handling Dust Collector	0.0025 gr/dscf	Enclosed emission points and follow manufacturer recommendations for operations and maintenance
7b	South Underbunker Dust Collector	0.02 gr/dscf	Enclosed emission points and follow manufacturer recommendations for operations and maintenance
7c	North Coal Handling Dust Collector	0.02 gr/dscf	Limited Operation – This source serves as backup to EU 7a and operates less than 200 hours each year
52	Emergency Coal Storage Pile and Operations	Varies	Chemical Stabilizers, Wind Fencing, Covered Haul Vehicles, Watering, and Wind Awareness
51a	Fly Ash Dust Collector	0.02 gr/dscf	Enclosed emission points and follow manufacturer recommendations for operations and maintenance
51b	Bottom Ash Dust Collector	0.02 gr/dscf	Enclosed emission points and follow manufacturer recommendations for operations and maintenance

Table 6-4. Proposed SO_2 BACT Limits

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
DU 1	Six Coal Fired Boiler 3	230 MMBtu/hr	0.10 lb/MMBtu	Dry Sorbent Injection Limited Operation (336,000 tons/year combined) Low Sulfur Coal
DU 2	Six Coal Fired Boiler 4	230 MMBtu/hr	0.10 lb/MMBtu	
DU 3	Six Coal Fired Boiler 5	230 MMBtu/hr	0.10 lb/MMBtu	
DU 4	Six Coal Fired Boiler 6	230 MMBtu/hr	0.10 lb/MMBtu	
DU 5	Six Coal Fired Boiler 7	230 MMBtu/hr	0.10 lb/MMBtu	
DU 6	Six Coal Fired Boiler 8	230 MMBtu/hr	0.10 lb/MMBtu	
FWA 8	Backup Diesel-Fired Boiler 1	19 MMBtu/hr	15 ppmv S in fuel	Good Combustion Practices Limited Operation (600 hours/year combined) Combust ULSD
FWA 9	Backup Diesel-Fired Boiler 2	19 MMBtu/hr	15 ppmv S in fuel	
FWA 10	Backup Diesel-Fired Boiler 3	19 MMBtu/hr	15 ppmv S in fuel	
N/A	Diesel-Fired Boilers	Varies	15 ppmv S in fuel	Limited Operation (500 hours/year each, for non-emergency operation) Good Combustion Practices Combust ULSD
DU 8	Generator Engine	2,937 hp	15 ppmv S in fuel	Limited Operation (100 hours/year each, for non-emergency operation) Good Combustion Practices Combust ULSD
DU 10	Generator Engine	762 hp	15 ppmv S in fuel	
DU 11	Generator Engine	762 hp	15 ppmv S in fuel	
DU 13	Generator Engine	587 hp	15 ppmv S in fuel	
DU 15	Generator Engine	1,059 hp	15 ppmv S in fuel	
FWA 11	Caterpillar 3512	1,206 hp	15 ppmv S in fuel	Limit Operation (600 hours/year combined) Combust ULSD Good Combustion Practices
FWA 12	Caterpillar 3512	1,206 hp	15 ppmv S in fuel	
FWA 13	Caterpillar 3512	1,206 hp	15 ppmv S in fuel	
DU 9	Generator Engine	353 hp	15 ppmv S in fuel	Limited Operation (100 hours/year each, for non-emergency operation) Good Combustion Practices Combust ULSD
DU 12	Generator Engine	82 hp	15 ppmv S in fuel	
DU 14	Generator Engine	320 hp	15 ppmv S in fuel	
DU 16	Generator Engine	212 hp	15 ppmv S in fuel	
DU 17	Generator Engine	176 hp	15 ppmv S in fuel	
DU 18	Generator Engine	212 hp	15 ppmv S in fuel	
DU 19	Generator Engine	71 hp	15 ppmv S in fuel	

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
DU 20	Generator Engine	35 hp	15 ppmv S in fuel	Limited Operation (100 hours/year each, for non-emergency operation) Good Combustion Practices Combust ULSD
DU 21	Generator Engine	95 hp	15 ppmv S in fuel	
DU 22	Generator Engine	35 hp	15 ppmv S in fuel	
DU 23	Generator Engine	155 hp	15 ppmv S in fuel	
DU 24	Generator Engine	50 hp	15 ppmv S in fuel	
DU 25	Generator Engine	18 hp	15 ppmv S in fuel	
DU 26	Generator Engine	68 hp	15 ppmv S in fuel	
DU 27	Generator Engine	274 hp	15 ppmv S in fuel	
DU 28	Generator Engine	274 hp	15 ppmv S in fuel	
DU 30	Lift Pump Engine	75 hp	15 ppmv S in fuel	
DU 32	Lift Pump Engine	75 hp	15 ppmv S in fuel	
DU 33	Lift Pump Engine	75 hp	15 ppmv S in fuel	
DU 34	Well Pump Engine	220 hp	15 ppmv S in fuel	
DU 35	Well Pump Engine	55 hp	15 ppmv S in fuel	
DU 36	Well Pump Engine	220 hp	15 ppmv S in fuel	
DU 29a	Lift Pump Engine	74 hp	15 ppmv S in fuel	
DU 31a	Lift Pump Engine	74 hp	15 ppmv S in fuel	
FWA 26	QSB7-G3 NR3	295 hp	15 ppmv S in fuel	
FWA 27	4024HF285B	67 hp	15 ppmv S in fuel	
FWA 28	CAT C9 GENSET	398 hp	15 ppmv S in fuel	
FWA 29	TM30UCM	47 hp	15 ppmv S in fuel	
FWA 30	JW64-UF30	275 hp	15 ppmv S in fuel	
FWA 31	DDFP-04AT	235 hp	15 ppmv S in fuel	
FWA 32	DDFP-04AT	235 hp	15 ppmv S in fuel	
FWA 33	DDFP-04AT	235 hp	15 ppmv S in fuel	
FWA 34	DDFP-04AT	235 hp	15 ppmv S in fuel	
FWA 35	N-855-F	240 hp	15 ppmv S in fuel	
FWA 36	N-855-F	240 hp	15 ppmv S in fuel	
FWA 37	JU4H-UF40	94 hp	15 ppmv S in fuel	
FWA 38	PDFP-06YT	120 hp	15 ppmv S in fuel	
FWA 39	PDFP-06YT	120 hp	15 ppmv S in fuel	

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

DIVISION OF AIR QUALITY
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October 20, 2017

Rich Morris
Directorate of Public Works-Environmental Division
U.S. Army Fort Wainwright
Attn. Richard Morris-Building 3023
1046 Marks Rd
Fort Wainwright, AK 99703

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum for Fort Wainwright by December 22, 2017

Dear Mr. Morris:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that Fort Wainwright and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to a Serious Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measure (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as Ft. Wainwright. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analysis is a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)
[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(4)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.
[3] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

to Mr. Eric Dick at Fort Wainwright on May 11, 2017 notifying him of the reclassification to Serious and included a request for the BACT analysis to be completed by August 8, 2017. The BACT analysis from Fort Wainwright, which included emission units found in Operating Permits AQ1121TVP02 Revision 2 and AQ0236TVP03 Revision 2, was submitted by email to the Department on July 13, 2017.

ADEC reviewed the BACT analysis provided for Fort Wainwright and is requesting additional information to assist it in making a legally and practicably enforceable BACT determination for the source. ADEC requests a response by December 22, 2017. If ADEC does not receive a response to this information request by this date, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facility's infrastructure and without additional information may select a more stringent BACT for your facility in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public comment along with any precursor demonstrations and RACM analysis before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes a final BACT determination for Fort Wainwright, it must include the determination in the Alaska's Serious SIP that then ultimately requires approval by EPA.[1] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented prior to June 9, 2021 – 4 years after reclassification.[2]

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM) consideration. MSMs will be a required element of the state implementation plan if the State applies for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

ADEC appreciates the cooperation that we've received from Fort Wainwright. ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Denise Koch, Director
Division of Air Quality

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[1] https://www.gpo.gov/fdsys/pkg/USCODE-2011-title42/html/USCODE-2011-title42-chap85-subchapI-partD-subpart4-sec7513a.htm

[2] 40 CFR §51.1010(4)

Enclosures:

October 20, 2017	Request for Additional Information for Fort Wainwright BACT Analysis;
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units) to Eric Dick, Environmental Manager US Army Fort Wainwright
April 24, 2015	Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units) to Kathleen Hook, Environmental Program Manager, Doyon Utilities, LLC

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality
Jim Plosay, ADEC/ Air Quality
Aaron Simpson, ADEC/Air Quality
Eric Dick/U.S. Army (Fort Wainwright)
Tim Hamlin, EPA Region 10
Zach Hedgpeth, EPA Region 10

ADEC Request for Additional Information
Fort Wainwright – Doyon Utilities
BACT Analysis Review
HydroGeoLogic, Inc. Report, June 2017

October 20, 2017

Please address the following comments by providing the additional information identified by December 22, 2017. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public comment. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public comment period or based upon the new information provided in response to this information request.

This document does not represent a final BACT determination by ADEC. Please contact Aaron Simpson at aaron.simpson@alaska.gov with any questions regarding ADEC's comments.

Draft Comments

1. Equipment Life – Page 4-2 of the analysis states "The BACT analysis for all control technologies assumes a 10-year useful life." ADEC identified that the EPA Air Pollution Control Cost Manual[1] (cost manual) uses a hypothetical example that assumes the control equipment has a useful life of ten years. However the cost analysis must use a reasonable estimate of the actual life of the control equipment for each control technology. As indicated in the proposed rule for Texas and Oklahoma Federal Implementation Plan for Regional Haze and Interstate Transport of Pollution Affecting Visibility – EPA-R06-OAR-2014-0754; Federal Register, Vol. 79, No. 241, 74818 [2] EPA indicated that:

   > "In determining the cost of scrubbers in our prior Oklahoma FIP, we used a lifetime of 30 years. In so doing, we noted that scrubber vendors indicate that the lifetime of a scrubber is equal to the lifetime of the boiler, which might easily be over 60 years. We also noted that many scrubbers that were installed between 1975 and 1986 are still in operation today (e.g., Coyote Station, H.L. Spurlock Unit 2, East Bend Unit 2, Laramie River Unit 3, Cholla 5, Basin Electric, Mitchell Unit 33, and all of the units in Table 30 that currently have scrubbers). Further, we noted that standard cost estimating handbooks and published papers report 30 years as a typical life for a scrubber and that many utilities routinely specify 30+ year lifetimes in requests for proposal and to evaluate proposals."

   In order to use an equipment life that is shorter than 30 years evidence must be provided to support the claim that "DU [Central Heat and Power Plant] is nearing the end of the useful design life cycle." This evidence could include information regarding the actual age of currently

[1] U.S. EPA OAQPS Air Pollution Control Cost Manual, 6th Edition [EPA/452/B-02-001]
[2] https://www.regulations.gov/document?D=EPA-R06-OAR-2014-0754-0001

operating control equipment, or design documents for associated process equipment such as boilers.

2. DSI Cost Analysis – The cost manual does not currently include a chapter covering dry sorbent injection (DSI). However, as part of their Regional Haze FIP for Texas, EPA Region 6 developed cost estimates for DSI as applied to a large number of coal fired utility boilers. See the Technical Support Documents for the Cost of Controls Calculations for the Texas Regional Haze Federal Implementation Plan (Cost TSD) for additional information. The Cost TSD and associated spreadsheets are located at: https://www.regulations.gov/document?D=EPA-R06-OAR-2014-0754-0008. Please update the cost analysis for DSI and provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Additionally, see Comments 7, 11, and 12 for additional information related to retrofit costs, baseline emissions, and factor of safety.
3. SNCR Cost Analysis – The EPA has recently updated the cost manual chapter pertaining to SNCR, and developed a cost spreadsheet to be used for evaluation of this technology for cost effectiveness. The cost analysis submitted as part of this BACT analysis[3] uses the EPA cost spreadsheet. Please update the cost analysis using the unrestricted potential to emit for each of the emissions units or propose operational limits (i.e., 300,000 tons of coal per year). Additionally, see Comments 7, 11, and 12 for additional information related to retrofit costs, baseline emissions, and factor of safety.
4. SCR Cost Analysis – The EPA has recently updated the cost manual chapter pertaining to SCR, and developed a cost spreadsheet to be used for evaluation of this technology for cost effectiveness. The cost analysis submitted as part of this BACT analysis[4] uses the EPA cost spreadsheet. Please update the cost analysis using the unrestricted potential to emit for each of the emissions units or propose operational limits. Additionally, see Comments 7, 11, and 12 for additional information related to retrofit costs, baseline emissions, and factor of safety.
5. BACT limits – BACT limits by definition, are numerical emission limits. However regulation allows a design, equipment, or work/operational practices if technological or economic limitations make a measurement methodology infeasible. Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for pollutant for each emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. Measures to minimize the occurrence of these periods, or to minimize emissions during these periods are control options. Combinations of steady-state control options and SSM control options can be combined to create distinct control strategies. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).
6. Good Combustion Practices –For each emission unit type (coal boilers, distillate boilers, engines, and material handling) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices. Include any work or operational practices that will be implemented and describe how continuous compliance with good combustion practices will be achieved.

[3] "sncr_cost_manual_spreadsheet_2016_vf Ft Wainwright.xlsm"
[4] "scr_cost_manual_spreadsheet_2016_vf Ft Wainwright.xlsm"

7. Retrofit Costs – EPA's Control Cost Manual indicates that study-level cost estimates (± 30 percent) should not include a retrofit factor greater than 30 percent, so detailed cost estimates (± 5 percent) is required for higher factors. High retrofit cost factors (50 percent or more) may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement). Provide detailed cost analyses and justification for difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analysis.
8. Provide an economic analysis for low-NOx burners (LNBs) and flue gas recirculation (FGR) for one of the diesel-fired boilers, not proposed as limited operation (FWA EUs 8 – 10). Identify all small boilers with emission unit identification numbers. Provide in the analysis: the control efficiency associated with LNBs and FGR, Captured Emissions (tons per year), Emissions Reduction (tons per year), Capital Costs (2017 dollars), Operating Costs (dollars per year), Annualized Costs (dollars per year), and Cost Effectiveness (dollars per ton) using EPA's cost manual.
9. Identify the control efficiencies proposed for limited operation of the small diesel-fired boilers (FWA EUs 8 – 10). If limited operation is not selected for the 24 other small boilers (list EU ID numbers), identify the energy, environmental, economic impacts and other costs used to remove limited operation from the analysis. Include numerical NOx emission limits, work, or operational practices that will be implemented for the small boilers and describe how continuous compliance with the BACT limits will be achieved.
10. Identify control efficiencies for limited operation and installation of turbochargers and aftercoolers for diesel-fired engines to be used to rank the technically feasible control technologies. If the proposed control efficiencies of limited operation or installation of turbochargers and aftercoolers is greater than that of SCR, rank the control technologies to remove SCR from the top-down BACT analysis. If SCR is ranked as a higher control efficiency for reduction of NOx, provide justification as to why SCR can be removed from the analysis. If the engines only operate infrequently, as indicated in the analysis, provide a justification for why limited operation cannot be proposed as an enforceable limit, or provide an economic analysis that indicates that the cost effectiveness of installing SCR or turbochargers and aftercoolers would have an adverse economic impact. Identify how many hours the units would have to operate for SCR to become economically feasible for these units.
11. Include the baseline emissions for all emission units included in the analysis. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). NSPS and NESHAP requirements are not considered in calculating the baseline emissions. The baseline is usually the legal limit that would exist, but for the BACT determination. Baseline takes into account the effect of equipment that is part of the design of the unit (e.g., water injection and LNBs) because they are considered integral components to the unit's design. If the uncontrolled emission rate is 'soft,' run the cost effectiveness calculations using two or three different baselines.
12. If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.

13. Please propose numerical emission limits for the diesel-fired engines DU EUs 8 through 28, 30, 32 through 36, 29a, and 31a and FWA EUs 11, 12, 13, and 26 – 39. Provide the source of the emission factor (e.g., vendor data, AP-42 emission factor, EPA Tier Certified Engine, or NSPS Subpart IIII). Please identify what constitutes "good housekeeping practices" for DU EU 15 and describe how continuous compliance with these practices is BACT for the unit.

14. Include scrubbers and limited operation in the review of PM-2.5 control technologies for diesel-fired boilers. Rank the control technologies by efficiency (specify % control). Select the best performing control technology as BACT or provide specific energy, environmental, and economic impacts and other costs justification for why each better performing control technology was not selected instead of good combustion practices. Provide a numerical PM-2.5 emission limit for the diesel-fired boilers or identify the work or operational practices that will be utilized to ensure compliance with proposed limits.

15. Include positive crankcase ventilation (closed crank ventilation system) and limited operation in the review of PM-2.5 control technologies for engines. Rank the control technologies (include low ash fuel) by efficiency (specify % control). Select the best performing control technology as BACT or provide specific energy, environmental, and economic impacts and other costs justification for why each better performing control technology was not selected instead of combustion of ULSD (low ash fuel). Revise the economic analysis for PM-2.5 emission controls for engines to reflect a calculation based on the units' potential to emit, not 500 hours per year (i.e., 8,760 hours per year or enforceable permit limits). Provide numerical PM-2.5 emission limits for the engines or identify the work or operational practices that will be utilized as BACT for the diesel-fired engines.

16. Provide an analysis of why enclosures are not technically feasible for the coal pile storage. Covering a stockpile is a proven control method used in pulverized mineral processing operations. Additionally, provide an analysis of why wetting agents and watering for dust suppression is not considered technically feasible during the summer months (i.e., when the ambient temperature is above freezing). Provide a numerical PM-2.5 emission limit for the Emergency Coal Storage Pile and Operations or identify the work or operational practices that will be utilized as BACT for the material handling operations.

THE STATE of ALASKA
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Department of Environmental Conservation

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April 24, 2015

Eric Dick, Environmental Manager
U.S. Army Fort Wainwright
ATTN: IMFW-PWE (E. Dick)
1060 Gaffney Road, # 4500
Fort Wainwright, AK 99703-4500

Subject: Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units)

Dear Mr. Dick:

Portions of the Fairbanks North Star Borough are in nonattainment with the 24-hour National Ambient Air Quality Standard for Fine Particulate Matter (PM 2.5). The Alaska Department of Environmental Conservation (ADEC) expects that the Environmental Protection Agency (EPA) will change the nonattainment designation from a Moderate Area to a Serious Area in June 2016. Once EPA designates the area as Serious, an 18-month clock begins for submittal of an implementation plan that includes best available control technologies (BACT) analysis and determination for stationary sources with over 70 tons per year (TPY) potential to emit (PTE) for PM2.5 or its precursors.

ADEC has neither the funding nor the in depth knowledge of your facility's infrastructure to determine the most appropriate BACT for your facility. Without the information or resources necessary to conduct detailed cost analysis and produce supporting documentation, ADEC may select a more stringent BACT for your facility in order to be approvable by EPA. In addition, 18 months is likely not adequate to complete a thorough BACT analysis.

Therefore, ADEC requests that your facility voluntarily begin the BACT analysis. We request that you submit an initial BACT analysis to ADEC by December 2015 and the final BACT analysis by March 2016 to ADEC. ADEC is required to make a BACT determination for every eligible facility within the designated PM2.5 nonattainment area and final BACT determinations are ultimately reviewed by EPA and subject to federal approval as part of the federally required PM2.5 implementation plan.

<u>Background</u>

EPA required that ADEC submit a State Implementation Plan (SIP) because portions of the Fairbanks North Star Borough (FSNB) are in nonattainment with the health based 24-hour National Ambient Air Quality Standard for PM2.5. ADEC submitted an initial, Moderate Area PM2.5 SIP for FNSB to EPA on December 31, 2014.

Unfortunately, this Moderate Area SIP was developed as an impracticable SIP because modeling was unable to demonstrate that attainment with the health standard was possible by December 30, 2015. Preliminary air monitoring results also indicate that FNSB will not demonstrate attainment in 2015. Attainment is calculated on a rolling three year average of the highest 98th percentile concentration at each monitor. When those monitoring results become final in May 2016 and an official three year design value is calculated, the FNSB non-attainment area will remain over the 24-hr PM 2.5 standard of 35 $\mu g/m^3$. The final determination of this design value will result in the FNSB non-attainment area being reclassified from a Moderate Area to a Serious Area[1] (40 CRF Parts 50, 51 and 93). This reclassification will happen by operation of law as outlined in Clean Air Act Sections 188 and 189. It is anticipated that the formal designation to Serious Area will occur in June 2016.

A Serious Area designation will result in several new, more stringent requirements, one of which is that all source categories in the nonattainment area that meet the BACT threshold of 70 TPY PTE for $PM_{2.5}$ and its precursor pollutants (NOx, SO2, VOC, NH3) must be analyzed for Best Available Control Measures (BACM). As part of BACM, a Best Available Control Technologies (BACT) analysis will be required. The Serious Area BACT trigger requires the same approach as a PSD/NSR BACT project. A Serious non-attainment area BACT limit is set using a top-down analysis on a case-by-case basis taking into account energy, environmental and economic impacts, and costs. The analysis must include all emission units at the source.

The timelines for completion of the BACT analysis, subsequent BACT determination, and the submittal of the Serious Area SIP are outlined in the preamble of the Particulate Matter 10 (PM10) rule and reconfirmed in the newly proposed $PM_{2.5}$ Implementation Rule[2]. Both rules require a completed SIP 18 months after designation to Serious. This 18 month time period does not allow enough time to thoroughly evaluate BACT, update the emission inventory, complete the modeling and allow for development and processing for a Serious Area SIP.

ADEC believes that it is best for facilities to complete the BACT analysis for their own facilities. ADEC does not have the funding to develop the analysis nor the in depth knowledge of each sources' infrastructure. ADEC would therefore base the cost analysis on the installation of control equipment without being able to factor in all the costs associated with retrofitting existing equipment. Without the detailed cost analysis and supporting documentation to support less stringent BACT options, it is doubtful that the BACT portions of the Serious SIP will be approvable without using the most stringent measures.

By requesting an early BACT analysis for facilities before the official Serious Area designation, it will help ADEC meet the following timelines and ultimately submit a Serious Area SIP to EPA by the

[1] 40 CFR Parts 50,51 and 93 http://www.epa.gov/airquality/particlepollution/actions.html

[2] http://www.epa.gov/airquality/particlepollution/actions.html

required due date. Early analysis also has the potential to increase flexibility for each Stationary Source under the rules.

- Serious Area SIP inventory development starts: January, 2015
- BACT kick off meeting: March 5, 2015
- Submit initial BACT results to ADEC: December, 2015
- Submit complete/final BACT analysis to ADEC: March, 2016
- Serious Area SIP modeling by ADEC starts: March, 2016
- Serious Area designation by EPA (Expected): June, 2016
- Serious Area SIP draft: December, 2016
- Serious Area SIP public notice period: February, 2017
- Serious Area SIP submitted by ADEC to EPA: December, 2017

Meeting the BACT analysis requirements is a major component of a Serious SIP. This is a challenging issue. It is important that ADEC accurately reflect the contributions of industrial sources to the air pollution problem and the potential improvements available within this emission sector along with the other emission sources in the community.

ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Denise Koch, Director
Division of Air Quality

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
John Kuterbach, ADEC/ Air Quality
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality
Kathleen Hook/ Doyon Utilities, LLC

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April 24, 2015

Kathleen Hook
Environmental Program Manager
Doyon Utilities, LLC
PO Box 74040
Fairbanks, AK 99707

Subject: Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units)

Dear Ms. Hook:

Portions of the Fairbanks North Star Borough are in nonattainment with the 24-hour National Ambient Air Quality Standard for Fine Particulate Matter (PM 2.5). The Alaska Department of Environmental Conservation (ADEC) expects that the Environmental Protection Agency (EPA) will change the nonattainment designation from a Moderate Area to a Serious Area in June 2016. Once EPA designates the area as Serious, an 18-month clock begins for submittal of an implementation plan that includes best available control technologies (BACT) analysis and determination for stationary sources with over 70 tons per year (TPY) potential to emit (PTE) for PM2.5 or its precursors.

ADEC has neither the funding nor the in depth knowledge of your facility's infrastructure to determine the most appropriate BACT for your facility. Without the information or resources necessary to conduct detailed cost analysis and produce supporting documentation, ADEC may select a more stringent BACT for your facility in order to be approvable by EPA. In addition, 18 months is likely not adequate to complete a thorough BACT analysis.

Therefore, ADEC requests that your facility voluntarily begin the BACT analysis. We request that you submit an initial BACT analysis to ADEC by December 2015 and the final BACT analysis by March 2016 to ADEC. ADEC is required to make a BACT determination for every eligible facility within the designated PM2.5 nonattainment area and final BACT determinations are ultimately reviewed by EPA and subject to federal approval as part of the federally required PM2.5 implementation plan.

Background

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Unfortunately, this Moderate Area SIP was developed as an impracticable SIP because modeling was unable to demonstrate that attainment with the health standard was possible by December 30, 2015. Preliminary air monitoring results also indicate that FNSB will not demonstrate attainment in 2015. Attainment is calculated on a rolling three year average of the highest 98th percentile concentration at each monitor. When those monitoring results become final in May 2016 and an official three year design value is calculated, the FNSB non-attainment area will remain over the 24-hr PM 2.5 standard of 35 $\mu g/m^3$. The final determination of this design value will result in the FNSB non-attainment area being reclassified from a Moderate Area to a Serious Area[1] (40 CRF Parts 50, 51 and 93). This reclassification will happen by operation of law as outlined in Clean Air Act Sections 188 and 189. It is anticipated that the formal designation to Serious Area will occur in June 2016.

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- BACT kick off meeting: March 5, 2015
- Submit initial BACT results to ADEC: December, 2015
- Submit complete/final BACT analysis to ADEC: March, 2016
- Serious Area SIP modeling by ADEC starts: March, 2016
- Serious Area designation by EPA (Expected): June, 2016
- Serious Area SIP draft: December, 2016
- Serious Area SIP public notice period: February, 2017
- Serious Area SIP submitted by ADEC to EPA: December, 2017

Meeting the BACT analysis requirements is a major component of a Serious SIP. This is a challenging issue. It is important that ADEC accurately reflect the contributions of industrial sources to the air pollution problem and the potential improvements available within this emission sector along with the other emission sources in the community.

ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Denise Koch, Director
Division of Air Quality

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
John Kuterbach, ADEC/ Air Quality
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality
Eric Dick/U.S. Army (Fort Wainwright)

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

DIVISION OF AIR QUALITY
Director's Office

[illegible]

CERTIFIED MAIL:7017 3040 0000 4359 5196
Return Receipt Requested

September 13, 2018

Rich Morris
Directorate of Public Works Environmental Division
U.S. Army Fort Wainwright
Attn. Richard Morris-Building 3023
1046 Marks Rd
Fort Wainwright, AK 99703

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum for Fort Wainwright by November 1, 2018

Dear Mr. Morris:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that Fort Wainwright and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to a Serious Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measure (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as Ft. Wainwright. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analysis is a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an email

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 [illegible] (0001.CER.pdf)

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(4)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.

[3] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.

to Mr. Eric Dick at Fort Wainwright on May 11, 2017 notifying him of the non-attainment area reclassification to Serious and included a request for the BACT analysis to be completed by August 8, 2017. The BACT analysis from Fort Wainwright, which included emission units found in Operating Permits AQ1121TVP02 Revision 2 and AQ0236TVP03 Revision 2, was submitted by email to the Department on July 13, 2017.

On March 22, 2018, ADEC released a preliminary draft of the BACT determination for Fort Wainwright for public discussion on its website at: http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip-development. As indicated in the release, this document is a work in progress. ADEC received additional information from Doyon Utilities and EPA on the preliminary draft BACT determination and expects to make changes to the determination based upon this input. Therefore, ADEC is requesting additional information from Fort Wainwright to assist it in making a legally and practicably enforceable BACT determination for the source.

Specifically, ADEC requests that Fort Wainwright review the cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the cost effectiveness calculations and indicates that the model is intended to calculate estimated total project cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent and the gross generating capacity of the plant. Please use this spreadsheet to calculate the cost effectiveness of SO_2 removal in dollars per ton and identify all assumptions and technical justifications used in the analysis.

If ADEC does not receive a response to this information request by November 1, 2018, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facility's infrastructure and without additional information, may select a more stringent BACT for your facility in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public review along with any precursor demonstrations and RACM analyses before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes a final BACT determination for Fort Wainwright, it must include the determination in Alaska's Serious SIP that then ultimately requires approval by EPA.[4] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented prior to June 9, 2021 - 4 years after reclassification.[5]

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM)

[4] https://www.gpo.gov/fdsys/pkg/USCODE-2011-title42/html/USCODE-2011-title42-chap85-subchapI-partD-subpart4-sec7513a.htm
[5] 40 CFR 51.1010(4)

consideration. MSMs will be a required element of the state implementation plan if the State applies for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

ADEC appreciates the cooperation that we've received from Fort Wainwright. ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Denise Koch, Director
Division of Air Quality

Enclosures:

September 10, 2018	ADEC Request for Additional Information for Fort Wainwright BACT Analysis
May 23, 2018	Doyon Utilities Comments Addressing the Preliminary Best Available Control Technology Determination for Fort Wainwright US Army Garrison and Doyon Utilities
May 21, 2018	EPA Comments on ADEC Preliminary Draft Serious SIP Development Materials for the Fairbanks Serious PM-2.5 nonattainment Area
October 20, 2017	Request for Additional Information for Fort Wainwright BACT Analysis;
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units) to Eric Dick, Environmental Manager US Army Fort Wainwright
April 24, 2015	Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units) to Kathleen Hook, Environmental Program Manager, Doyon Utilities, LLC

cc: Larry Hartig, ADEC/Commissioner's Office
Alice Edwards, ADEC/Commissioner's Office
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/Air Quality
Jim Plosay, ADEC/Air Quality
Aaron Simpson, ADEC/Air Quality
Eric Dick, U.S. Army (Fort Wainwright)
Tim Hamlin, EPA Region 10
Zach Hedgpeth, EPA Region 10
Dan Brown, EPA Region 10

ADEC Request for Additional Information
Fort Wainwright – Doyon Utilities
BACT Analysis Review
HydroGeoLogic, Inc. Report, June 2017

September 10, 2018

Please address the following comments by providing the additional information identified by November 1, 2018. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public comment. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public comment period or based upon the new information provided in response to this information request.

This document does not represent a final BACT determination by ADEC. Please contact Aaron Simpson at aaron.simpson@alaska.gov with any questions regarding ADEC's comments.

Draft Comments

1. Equipment Life – Page 4-2 of the analysis states "The BACT analysis for all control technologies assumes a 10-year useful life." ADEC identified that the EPA Air Pollution Control Cost Manual[1] (cost manual) uses a hypothetical example that assumes the control equipment has a useful life of ten years. However the cost analysis must use a reasonable estimate of the actual life of the control equipment for each control technology. As indicated in the proposed rule for Texas and Oklahoma Federal Implementation Plan for Regional Haze and Interstate Transport of Pollution Affecting Visibility – EPA-R06-OAR-2014-0754; Federal Register, Vol. 79, No. 241, 74818 [2] EPA indicated that:

   > "In determining the cost of scrubbers in our prior Oklahoma FIP, we used a lifetime of 30 years. In so doing, we noted that scrubber vendors indicate that the lifetime of a scrubber is equal to the lifetime of the boiler, which might easily be over 60 years. We also noted that many scrubbers that were installed between 1975 and 1986 are still in operation today (e.g., Coyote Station, H.L. Spurlock Unit 2, East Bend Unit 2, Laramie River Unit 3, Cholla 5, Basin Electric, Mitchell Unit 33, and all of the units in Table 30 that currently have scrubbers). Further, we noted that standard cost estimating handbooks and published papers report 30 years as a typical life for a scrubber and that many utilities routinely specify 30+ year lifetimes in requests for proposal and to evaluate proposals."

   In order to use an equipment life that is shorter than 30 years evidence must be provided to support the claim that "DU [Central Heat and Power Plant] is nearing the end of the useful design life cycle." This evidence could include information regarding the actual age of currently

[1] U.S. EPA OAQPS Air Pollution Control Cost Manual, 6th Edition [EPA/452/B-02-001]
[2] https://www.regulations.gov/document?D=EPA-R06-OAR-2014-0754-0001

operating control equipment, or design documents for associated process equipment such as boilers.

2. SNCR Cost Analysis – The EPA has recently updated the cost manual chapter pertaining to SNCR, and developed a cost spreadsheet to be used for evaluation of this technology for cost effectiveness. The cost analysis submitted as part of this BACT analysis[3] uses the EPA cost spreadsheet. Please update the cost analysis using the unrestricted potential to emit for each of the emissions units or propose operational limits (i.e., 300,000 tons of coal per year), and provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Additionally, see Comments 7, 10, and 11 for additional information related to retrofit costs, baseline emissions, and factor of safety.

3. SCR Cost Analysis – The EPA has recently updated the cost manual chapter pertaining to SCR, and developed a cost spreadsheet to be used for evaluation of this technology for cost effectiveness. The cost analysis submitted as part of this BACT analysis[4] uses the EPA cost spreadsheet. Please update the cost analysis using the unrestricted potential to emit for each of the emissions units or propose operational limits, and provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Additionally, see Comments 7, 10, and 11 for additional information related to retrofit costs, baseline emissions, and factor of safety.

4. BACT limits – BACT limits by definition, are numerical emission limits. However regulation allows a design, equipment, or work/operational practices if technological or economic limitations make a measurement methodology infeasible. Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for each pollutant and emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. Measures to minimize the occurrence of these periods, or to minimize emissions during these periods are control options. Combinations of steady-state control options and SSM control options can be combined to create distinct control strategies. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

   In comments from Doyon Utilities on May 23, 2018, they correctly identify that PM emissions from fuel-fired EUs are greater than actual PM-2.5 emissions from the same EU. They also requested clarification for the rationale for selecting a PM-2.5 emission rate of 0.05 grain/dscf. This value was provided in the June 2017 BACT Technical Memorandum from the U.S. Army Corp of Engineers. Therefore, please provide a basis for the 0.05 grain/dscf numerical BACT emissions limit for PM-2.5 emissions from the industrial coal fired boilers.

5. Good Combustion Practices – For each emission unit type (coal boilers, distillate boilers, engines, and material handling) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices. Include any work or operational practices that will be implemented and describe how continuous compliance with good combustion practices will be achieved.

[3] "sncr_cost_manual_spreadsheet_2016_vf Ft Wainwright.xlsm"

[4] "scr_cost_manual_spreadsheet_2016_vf Ft Wainwright.xlsm"

6. Site-Specific Quotes Needed – The cost analyses must be based on emission unit-specific quotes for capital equipment purchase and installation costs at Fort Wainwright. This retrofit project must be considered in order to obtain reliable study/budget level (+/- 30%) cost estimates which are appropriate to use as the basis for decision making in determining BACT.

7. Retrofit Costs – EPA's Control Cost Manual indicates that study-level cost estimates (± 30 percent) should not include a retrofit factor greater than 30 percent, so detailed cost estimates (± 5 percent) are required for higher factors. High retrofit cost factors (50 percent or more) may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement). Provide detailed cost analyses and technical justification for difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analysis.

8. Condensable Particulate Matter – Although the existing control technology on the coal fired boilers may be evaluated as to whether it meets the requirement for BACT for particulate matter, baghouses primarily reduce emissions of filterable particulate matter rather than condensable PM. Given that all condensable PM emitted by the coal fired boilers would be classified as PM-2.5, the BACT analyses must include consideration of control options for these emissions. Where control technologies evaluated for control of other pollutants may provide a collateral benefit in reducing emissions of PM-2.5, this should be evaluated as well.

9. Interest Rate – All cost analyses must use the current bank prime interest rate. This can be found online at https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table). Please revise the cost analyses as appropriate.

10. Baseline Emissions - Include the baseline emissions for each emission unit included in the analysis. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). NSPS and NESHAP requirements are not considered in calculating the baseline emissions. The baseline is usually the legal limit that would exist, but for the BACT determination. Baseline takes into account the effect of equipment that is part of the design of the unit (e.g., water injection and LNBs) because they are considered integral components to the unit's design. If the uncontrolled emission rate is 'soft,' run the cost effectiveness calculations using two or three different baselines.

11. Factor of Safety - If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.

12. Provide an economic analysis for low-NOx burners (LNBs) and flue gas recirculation (FGR) for one of the diesel-fired boilers, not proposed as limited operation (FWA EUs 8 – 10). Identify all small boilers with emission unit identification numbers. Provide technical justification for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Provide in the analysis: the control efficiency associated with LNBs and FGR, captured emissions (tons per year), emissions reduction (tons per year), capital costs (2017 dollars), operating costs (dollars per year), annualized costs (dollars per year), and cost effectiveness (dollars per ton) using EPA's cost manual.

13. Identify the control efficiencies proposed for limited operation of the small diesel-fired boilers (FWA EUs 8 – 10). If limited operation is not selected for the 24 other small boilers (list EU

numbers), identify the energy, environmental, economic impacts and other costs used to remove limited operation from the analysis. Include numerical NOx emission limits, work, or operational practices that will be implemented for the small boilers and describe how continuous compliance with the BACT limits will be achieved.

14. Identify control efficiencies for limited operation and installation of turbochargers and aftercoolers for diesel-fired engines to be used to rank the technically feasible control technologies. If the proposed control efficiencies of limited operation or installation of turbochargers and aftercoolers is greater than that of SCR, rank the control technologies to remove SCR from the top-down BACT analysis. If SCR is ranked as a higher control efficiency for reduction of NOx, provide justification as to why SCR can be removed from the analysis. If the engines only operate infrequently, as indicated in the analysis, provide a justification for why limited operation cannot be proposed as an enforceable limit, or provide an economic analysis that indicates that the cost effectiveness of installing SCR or turbochargers and aftercoolers would have an adverse economic impact. Please provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Identify how many hours the units would have to operate for SCR to become economically feasible for these units.
15. Please propose numerical emission limits for the diesel-fired engines DU EUs 8 through 28, 30, 32 through 36, 29a, and 31a and FWA EUs 11, 12, 13, and 26 – 39. Provide the source of the emission factor (e.g., vendor data, AP-42 emission factor, EPA Tier Certified Engine, or NSPS Subpart IIII). Please identify what constitutes "good housekeeping practices" for DU EU 15 and describe how continuous compliance with these practices is BACT for the unit.
16. Include scrubbers and limited operation in the review of PM-2.5 control technologies for diesel-fired boilers. Rank the control technologies by efficiency (specify % control). Select the best performing control technology as BACT or provide specific energy, environmental, and economic impacts and other costs justification for why each better performing control technology was not selected instead of good combustion practices. Please provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Provide a numerical PM-2.5 emission limit for the diesel-fired boilers or identify the work or operational practices that will be utilized to ensure compliance with proposed limits.
17. Include positive crankcase ventilation (closed crank ventilation system) and limited operation in the review of PM-2.5 control technologies for engines. Rank the control technologies (include low ash fuel) by efficiency (specify % control). Select the best performing control technology as BACT or provide specific energy, environmental, and economic impacts and other costs justification for why each better performing control technology was not selected instead of combustion of ULSD (low ash fuel). Revise the economic analysis for PM-2.5 emission controls for engines to reflect a calculation based on the units' potential to emit, not 500 hours per year (i.e., 8,760 hours per year or enforceable permit limits). Provide numerical PM-2.5 emission limits for the engines or identify the work or operational practices that will be utilized as BACT for the diesel-fired engines. Provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs).
18. Provide an analysis of why enclosures are not technically feasible for the coal pile storage. Covering a stockpile is a proven control method used in pulverized mineral processing

operations. Additionally, provide an analysis of why wetting agents and watering for dust suppression are not considered technically feasible during the summer months (i.e., when the ambient temperature is above freezing). Provide a numerical PM-2.5 emission limit for the Emergency Coal Storage Pile and Operations or identify the work or operational practices that will be utilized as BACT for the material handling operations.

19. Department research has indicated that a switch to low ash and low sulfur fuels in large and small diesel engines can reduce emissions of particulate matter. Please provide an analysis of the expected control efficiency reduction over the federal emissions standards (baseline) expected to be achieved by switching to a low ash or low sulfur fuel.

20. Please provide manufacturer information for DU EU 9 identifying the PM-2.5 emission factor that will be used in setting the numerical BACT limits for that unit.

21. Provide an economic analysis for circulating dry scrubber (CDS) SO_2 technology for the coal fired boilers (EUs 1-6). Provide in the analysis: the control efficiency associated with CDS, captured emissions (tons per year), emissions reduction (tons per year), capital costs (2017 dollars), operating costs (dollars per year), annualized costs (dollars per year), and cost effectiveness (dollars per ton) using EPA's cost manual. Please provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs).

22. Review the cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the cost effectiveness calculations and indicates that the model is intended to calculate estimated total project cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent and the gross generating capacity of the plant. Please use this spreadsheet to calculate the cost effectiveness of SO_2 removal in dollars per ton and identify all assumptions and technical justifications used in the analysis. In this analysis use a bottom-up cost estimating approach based on actual plant conditions. These conditions would include SO_2 emission rates based on current PTE, permit constraints (where applicable and enforceable), available space, ambient conditions, and local factors such as construction logistics, labor wage rates, and local sorbent costs.

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PO Box 74040
Fairbanks, AK 99707

May 23, 2018

Mr. Aaron Simpson
Alaska Department of Environmental Conservation
Division of Air Quality
P.O Box 111800
Juneau AK 99811-1800

Re: Comments Addressing the Preliminary Best Available Control Technology Determination for Fort Wainwright US Army Garrison and Doyon Utilities

Dear Mr. Simpson:

Doyon Utilities, LLC (DU) is providing the enclosed comments addressing the preliminary Best Available Control Technology (BACT) assessment that the Alaska Department of Environmental Conservation (ADEC) has prepared for the Fort Wainwright US Army Garrison and Doyon Utilities. DU has limited this review and comment effort to those emissions units that are operated by DU and that are included in Title V Permit AQ1121TVP02, Revision 2. DU has not provided comments addressing emissions units that are operated by the US Army Garrison.

DU appreciates this opportunity to provide comments addressing the preliminary BACT documents. DU understands that the preliminary BACT documents are a work in progress. DU also understands that ADEC hopes to receive additional information from the public as a result of the release of the preliminary draft BACT documents and that ADEC expects to make changes to the documents based upon this input.

The attached comments identify a number of concerns of varying degree of seriousness. The items discussed in the comments that are of most concern to DU are:

- The preliminary BACT analysis for sulfur dioxide (SO_2) emissions from the Central Heat and Power Plant (CHPP) boilers (Emissions Units (EUs) 1 through 6) identifies dry sorbent injection (DSI) as the preferred SO_2 emission control technology. The analysis that supports this determination is based on unsupported assumptions, use of a cost model that may not be appropriate for these boilers, and inconsistent SO_2 emission calculations. The analysis is also lacking site-specific engineering data. As a result, the analysis appears not to be defensible.
- The preliminary BACT analysis for SO_2 emissions from the CHPP boilers assumes a more stringent coal combustion limit and coal sulfur content than currently required, but does

not assess these options through the five-step BACT process or determine whether these assumptions are even valid.

- The preliminary $PM_{2.5}$ BACT analysis and draft BACT determinations for the material handling emissions units (EUs 7a, 7b, 7c, 51a, 51b, and 52) are confusing and unclear.
- The required methods to demonstrate compliance with the preliminary BACT limits are in many cases unclear or unspecified.
- Many of the preliminary $PM_{2.5}$ BACT emission limits are provided without supporting rationale, may not be appropriate as $PM_{2.5}$ emission limits, and/or may not be achievable.

Please contact Kathleen Hook at 907-455-1540 or khook@doyonutilities.com if you have any questions or would like to further discuss any specific comments.

Best Regards,

Shayne Coiley
Senior Vice President
Doyon Utilities, LLC

cc: Jim Plosay, ADEC
Kathleen Hook, DU
Courtney Kimball, SLR

Enclosure: Comments Addressing the Preliminary Best Available Control Technology Determination for Fort Wainwright US Army Garrison and Doyon Utilities Dated March 22, 2018

CO 18-061

Comments Addressing the Preliminary Best Available Control Technology Determination for Fort Wainwright US Army Garrison and Doyon Utilities Dated March 22, 2018

General Comments

1. Inadequate technical information is provided in the Preliminary Best Available Control Technology Determination (Preliminary Determination). This lack of information generally includes, but is not limited to, the following areas.
   - Little or no engineering data or rationale is provided to support the Alaska Department of Environmental Conservation (ADEC) preliminary determinations addressing whether an emission control technology is or is not technically feasible.
   - Little or no engineering data, cost data, or rationale is provided to support the preliminary determinations addressing whether an emission control technology is or is not Best Available Control Technology (BACT).
   - The methodology used to determine emissions reductions is typically not quantified.

   This lack of data and rationale is inconsistent with past ADEC insistence that the stationary sources provide a substantial level of detail and specific engineering data to support the BACT analyses that the stationary sources submitted to ADEC.

2. The Preliminary Determination tables that provide a comparison of emissions unit capacities and BACT emission limits for affected stationary sources (University of Alaska Fairbanks, Fort Wainwright, Golden Valley Electric Association (GVEA) North Pole Plant, and GVEA Zehnder Plant) generally have inconsistent units of measurement within each table. As a result, these tables have limited usefulness without further analysis being prepared.

3. In many cases, the Preliminary Determination does not identify the methods that must be used to verify compliance with the preliminary BACT limits. The methods to be used for verifying compliance should be identified so that the Permittees can determine whether the methods that ADEC intends to require are appropriate and whether the methods will be overly cumbersome and/or expensive.

Section 3. BACT Determination for Nitrogen Oxides (NO_X)

In Section 3 of the Preliminary Determination, ADEC states that "the NO_X controls proposed in this section are not planned to be implemented." Instead, ADEC is planning to submit a final precursor demonstration to the U.S. Environmental Protection Agency (EPA) "as justification not to require NO_X controls." As a result, Doyon Utilities (DU) has not reviewed this section of the Preliminary Determination and is not providing comments because:

- ADEC does not plan to implement the proposed NO_X BACT determinations, and
- Focusing on those sections of the Preliminary Determination that ADEC intends to implement is a better use of the short amount of time that was made available for this review.

DU will review any future NO_X BACT proposals and will provide comments if EPA does not approve the ADEC final precursor demonstration and the implementation of NO_X BACT emissions controls becomes mandatory.

Section 4. BACT Determination for Fine Fraction Respirable Particulate Matter ($PM_{2.5}$)

The ADEC preliminary $PM_{2.5}$ BACT analysis includes errors, assumptions, and inconsistencies that are of varying degree of concern. Each instance of concern is discussed below in no particular order of seriousness.

4. Section 4: The term "full steam baghouse" appears several times in the Preliminary Determination. The correct term is "full stream baghouse."

5. Section 4.1 (Industrial Coal-fired Boilers), Steps 4(b) and 5(b): The Preliminary Determination establishes a $PM_{2.5}$ emission limit of 0.05 grains per dry standard cubic foot (gr/dscf) for the coal-fired boilers, Emissions Units (EUs) 1 through 6. No basis for the selection of this $PM_{2.5}$ emission rate is provided, but the selected emission rate value is consistent with the particulate matter (PM) emission rate for industrial processes and fuel burning equipment established in 18 Alaska Administrative Code (AAC) 50.055(b)(1). This PM emission limit is commonly called the SIP PM emission limit. The appropriateness of using the SIP PM emission limit to establish a $PM_{2.5}$ emission limit is unclear because:
    - PM includes all filterable particulate matter regardless of size while $PM_{2.5}$ includes only filterable particulate matter with an nominal aerodynamic diameter of 2.5 microns, and
    - $PM_{2.5}$ includes all condensable matter while PM does not include any condensable matter.

    In many, but not all cases, actual PM emissions from a fuel-fired emissions unit are greater than the actual $PM_{2.5}$ emissions from that same emissions unit. If the assumption is being made that $PM_{2.5}$ emissions from EUs 1 through 6 are less than or equal to PM emissions, this assumption should be supported with existing source test results to confirm that compliance with the preliminary limit can be met. If this assumption is not being made, ADEC should explain more fully the rationale for selecting a $PM_{2.5}$ emission rate of 0.05 gr/dscf as the $PM_{2.5}$ BACT emission limit for EUs 1 through 6.

6. Section 4.1 (Industrial Coal-fired Boilers), Table 4-2: This table provides the total plant capacity for the listed stationary sources instead of individual boiler capacity. The preliminary $PM_{2.5}$ BACT emission limits are not presented in consistent units of measurement or are not provided in the table. As a result, the table is not useful for the intended comparative purpose.

7. Section 4.3 (Large Diesel-fired Engines), Step 1(f): This section cites "RBLC NO_X determinations." The correct reference is "RBLC information for $PM_{2.5}$ determinations."

8. Section 4.3 (Large Diesel-fired Engines), Steps 1 through 5: The ADEC rationale for the preliminary BACT determination of combusting ultra-low sulfur diesel (ULSD) is inconsistent for the following reasons.

- In Step 1(d), the use of low sulfur fuel is listed as an available and feasible emission control technology.
- Step 2 eliminates low sulfur fuel as technically infeasible which is inconsistent with the statement in Step 1 and incorrect. The use of low sulfur fuel is technically feasible, but the contribution of this technology toward reducing $PM_{2.5}$ emissions cannot be quantified.
- Step 3 does not address the use of ULSD.
- Step 5 requires the use of ULSD, with no supporting rationale or cost analysis. This determination is also inconsistent with the incorrect Step 2 conclusion that low sulfur fuel is not technically feasible.

Please make the appropriate corrections to Section 4.3. DU understands that the requirement to combust ULSD will likely remain unchanged for the large diesel-fired engines. Specifically, the preliminary sulfur dioxide (SO_2) BACT decision also requires the use of ULSD, so correcting this inconsistency in Section 4.3 will not eliminate the requirement to combust ULSD in the large diesel-fired engines. The combustion of ULSD is required in the large diesel-fired engines that are subject to 40 Code of Federal Regulations (CFR) 60 Subpart IIII.

9. Section 4.3 (Large Diesel-fired Engines), Step 4 and 5: A cost analysis is not provided to support the preliminary $PM_{2.5}$ BACT determinations identified in Step 5. Because each BACT determination must be based on technical and economic feasibility, the rationale for these preliminary determinations is incomplete, making the validity of the preliminary determinations questionable. Please provide the required economic feasibility analysis.

10. Section 4.3 (Large Diesel-fired Engines), Step 5(b): The Preliminary Determination is unclear with respect to whether the 500 hours per year operating limit in non-emergency situations is applicable to EUs 8, 10, 11, 13, and 15 individually or cumulatively. If the operating limit is cumulative, the limit is inconsistent with Title V Permit AQ1121TVP02 which allows EU 8 to be converted to a non-emergency engine with a limit of 500 hours per year. If the limit applies to each individual engine, the requirement is inconsistent with applicable requirements under 40 CFR 63 Subpart ZZZZ (or Subpart IIII, if applicable), which allows 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing.

11. Section 4.3 (Large Diesel-fired Engines), Table 4-6: This table cites manufacturer information for establishing the preliminary $PM_{2.5}$ BACT limit of 0.09 grams per horsepower-hour (g/hp-hr) for EU 15. The source of this manufacturer information is not provided in the Preliminary Determination and cannot otherwise be obtained to confirm this $PM_{2.5}$ emission rate is correct. An emission rate of 0.09 g/hp-hr is equivalent to 0.0002 pounds per horsepower-hour (lb/hp-hr). Potential emissions of $PM_{2.5}$ for EU 15 are currently calculated using an emission factor of 0.0007 lb/hp-hr per AP-42, Table 3.4-1. As a result, the preliminary BACT $PM_{2.5}$ limit of 0.09 g/hp-hr may not be appropriate or achievable for EU 15. Please provide the manufacturer information stating that a $PM_{2.5}$ emission rate of 0.09 g/hp-hr has been established for EU 15.

12. Section 4.4 (Small Emergency Engines), Step 5(a): The requirement to limit non-emergency operation of each of EUs 9, 12, 14, 16 through 28, 29a, 30, 31a, and 32 through 36 to 500 hours per year is

inconsistent with applicable requirements under 40 CFR 63 Subpart ZZZZ (or Subpart IIII, if applicable), which allows 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing.

13. Section 4.4 (Small Diesel-fired Engines), Steps 1 through 5: The ADEC rationale for the preliminary BACT determination of combusting ultra-low sulfur diesel (ULSD) is inconsistent for the following reasons.
    - In Step 1(d), the use of low sulfur fuel is listed as an available and technically feasible emission control technology.
    - Step 2 eliminates low sulfur fuel as technically infeasible which is inconsistent with the statement in Step 1 and incorrect. The use of low sulfur fuel is technically feasible, but the contribution of this technology toward reducing $PM_{2.5}$ emissions cannot be quantified.
    - Step 3 does not address the use of ULSD.
    - Step 5 requires the use of ULSD, with no supporting rationale or cost analysis. This determination is also inconsistent with the incorrect Step 2 conclusion that low sulfur fuel is not technically feasible.

    Please make the appropriate corrections to Section 4.4. DU understands that the requirement to combust ULSD will likely remain unchanged for the small diesel-fired engines. Specifically, the preliminary sulfur dioxide (SO_2) BACT decision also requires the use of ULSD, so correcting this inconsistency in Section 4.4 will not eliminate the requirement to combust ULSD in the small diesel-fired engines.

14. Section 4.4 (Small Diesel-fired Engines), Steps 4 and 5: A cost analysis is not provided to support the preliminary $PM_{2.5}$ BACT determinations identified in Step 5. Because each BACT determination must be based on technical and economic feasibility, the rationale for these preliminary determinations is incomplete, making the validity of the preliminary determinations questionable. Please provide the required economic feasibility.

15. Section 4.4 (Small Diesel-fired Engines), Table 4-9: The proposed preliminary $PM_{2.5}$ BACT limit of 7.21 E-04 pounds per horsepower-hour (lb/hp-hr) is the PM_{10} emission factor for gasoline-fired engines from Table 3.3-1 of AP-42. Using this emission factor is not appropriate for diesel-fired engines or for $PM_{2.5}$.

16. Section 4.5 (Material Handling): This section addresses the material handling emissions units (EUs 7a through 7c, 51a, 51b, and 52) but does not make a distinction between the material handling emissions units that can be equipped with fabric filter controls (EUs 7a through 7c, 51a, and 51b) and the emissions unit that cannot be equipped with a baghouse (EU 52, the emergency coal storage pile) Because a coal storage pile is a very different type of emissions unit, the section is not clear with respect to the types of emission control technologies that might be used for each listed emissions unit. As a result, EU 52 should be addressed separately for clarity.

    As an example of this confusion, Step 1(g) indicates that wind screens are not considered technically feasible for material handling units, but Step 2 states that all identified control technologies are

technically feasible. Wind screens may be an available and/or technically feasible control technology for a coal storage pile, but not necessarily for a dust collector. Conversely, fabric filters are identified as available and technically feasible in Step 1(a), but fabric filters are not an available control technology for coal storage piles.

17. Section 4.5 (Material Handling), Table 4-12: The proposed preliminary $PM_{2.5}$ BACT for EU 7c, the North Coal Handling Dust Collector, includes a 200 hours per year (hr/yr) operating limit. This emissions unit is a backup coal handling system that is used if the primary system coal handling system is not available. The Preliminary Determination does not explain the basis for this BACT operating limit. Pleased fully explain the rationale for imposing a BACT operating limit of 200 hr/yr on EU 7c.

18. Section 4.5 (Material Handling), Steps 4(e) and 5(c): The preliminary proposed $PM_{2.5}$ BACT emission limit of 0.48 tons per year (tpy) for EU 52 is 34 percent of the existing $PM_{2.5}$ potential to emit of 1.42 tpy. The Preliminary Determination does not provide the basis for the 0.48 tpy $PM_{2.5}$ BACT emission limit or explain the emission limit calculation methodology. Please fully explain the basis and rationale for imposing a $PM_{2.5}$ BACT emission limit of 0.48 tpy on EU 52.

19. Section 4.5 (Material Handling), Table 4-12: This table includes columns labeled "Current Controls" and "Current Emission Factors." The table does not provide preliminary proposed $PM_{2.5}$ BACT emission limits, which is inconsistent with the Table 4-12 title of "PM-2.5 BACT Control Technologies Proposed for Material Handling."

Section 5. BACT Determination for SO_2

The Preliminary Determination SO_2 BACT analysis includes errors, assumptions, and inconsistencies that are of varying degree of concern. These concerns are discussed below in no particular order of seriousness.

20. Section 5.1 (Industrial Coal-fired Boilers): In Table 5.3, the Preliminary Determination specifies SO_2 cost effectiveness for wet scrubbing and spray dry absorbers to be $10,788 per ton SO_2 removed and $11,136 per ton SO_2 removed, respectively. Although not explicitly stated, the Preliminary Determination implies that these two technologies are not economically feasible and so are not SO_2 BACT. While the economically feasibility analyses for these two control technologies likely underestimate actual costs, DU agrees that wet scrubbing and spray dry absorbers are not SO_2 BACT. As a result, comments addressing wet scrubbing or spray dry absorbers are not presented in this document.

    The preliminary proposed SO_2 BACT is dry sorbent injection (DSI) which the Preliminary Determination states has a cost effectiveness of $6,435 per ton SO_2 removed. This cost effectiveness determination is questionable and likely too low for the reasons provided below. Note that developing an accurate cost effectiveness for DSI would require a bottom-up cost estimate based on actual plant conditions.

- Cost Model Validity: The cost effectiveness spreadsheet provided by ADEC as a part of the preliminary SO_2 BACT determination was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the calculations that are in Row 25 of the spreadsheet. The S&L white paper states that the model is intended to calculate estimated Total Project Cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent (in this case Trona) on a tons per hour (tph) basis and the gross generating capacity of the plant. The white paper omits information that is necessary to ensure that the spreadsheet is properly applied to a specific situation, including:
  - Types of plants to which the model is applicable (utility power generation, combined heat and power (CHP), cogeneration, other);
  - Applicable number of boilers (single unit or multi-boiler installation);
  - Applicable size range;
  - Equipment included in the Total Purchased Cost (TPC) calculation;
  - On-site bulk storage capacity;
  - A basis for selecting a "Retrofit factor" other than "1.0"; and
  - Data and other information used to develop and support the equations used in the spreadsheet.

  Based on review of the cost effectiveness model and the supporting documentation, determining the validity of the results of the analysis is not possible. The concerns are rooted in three assumptions made by ADEC in preparing the cost model
  - ADEC assumed that the model is valid for a plant the size of Fort Wainwright.
    - The calculation for "Base Module" cost (Row 30 of the spreadsheet) is based on an equation that uses the predicted sorbent demand. The S&L white paper states that the equation was developed based on "Cost data for several DSI systems." No references or supporting information relating to these projects were provided. While the validity range for the equation was not identified, one piece of information that gives some indication of the applicable range. The equation has a discontinuity at 25 tph of sorbent flow. Given that the predicted total sorbent flow for all six coal-fired boilers at Fort Wainwright is 1.5 tph (based on the estimate in the Preliminary Determination), the Fort Wainwright boilers would be at the very bottom of the range of potential plant sizes. Without additional data to justify the cost calculation at very low sorbent injection rates, determining if the results of the equation are accurate is very difficult.
  - The Preliminary Determination assumes that multiple boilers can accurately be modeled as a lumped heat input in a single spreadsheet.
    - The S&L white paper does not identify the type or configuration of the plant on which the calculation was based. Data input fields included in the spreadsheet (unit size, gross heat rate) indicate that the analysis was developed based on a single power generation unit (single boiler, single steam turbine, no CHP or cogeneration).
    - Based on the inputs to the spreadsheet provided by ADEC, EUs 1 thorough 6 are being treated as a single, lumped heat input value. This approach is an oversimplification and will not accurately account for the equipment and utilities that will be necessary to independently operate six boilers. The actual installation will require six separate trains of sorbent processing and transport equipment. Each train contains a day bin, mills,

feeders, blowers, coolers, hoppers, piping, instrumentation, controls, electrical wiring and other supporting equipment. This need for separate systems complicates the design, increases overall footprint, and reduces the economy of scale that might be realized with a single larger unit. In theory, ADEC could possibly use the Retrofit Factor to account for this additional complexity, but without a method for determining the correct Retrofit Factor value, selecting any value other than "1.0" would be pure conjecture.

- The sorbent feed rate currently calculated for EUs 1 through 6 is very small. Should the model be revised to calculate the cost effectiveness on a per unit basis, the feed rate would be roughly one sixth of the current value. This change would further amplify concerns about the accuracy of the TPC calculation.

- ADEC assumed that the model is valid for a heat and power plant.
  - As discussed above, no information is available addressing the type of plant on which the S&L spreadsheet is based. The assumption is that the plant is a single power generation unit. A CHP plant differs significantly from a "traditional" power plant in that the steam produced in a CHP plant is not exclusively used to generate electricity. In an effort to make the spreadsheet work for this application, ADEC used "dummy" data in the "Unit Size (Gross)" and "Gross Heat Rate" fields so that the calculated "Heat Input" field showed the maximum heat input value for EUs 1 through 6 (1,380 million British thermal units per hour (MMBtu/hr)). This approach has unintended consequences relating to the accuracy of the direct annual costs. The fixed and variable operating and maintenance (O&M) costs are evaluated on a per kilowatt and a per megawatt basis respectively. Utilizing a "dummy" gross generation number to calculate annual costs may not produce an accurate result. Based on review, no method exists to accurately model the direct annual costs for an installation such as the Fort Wainwright EUs 1 through 6 by using the S&L spreadsheet.
  - The average maximum hourly heat input identified in Row 15 of the spreadsheet is incorrect. The value shown reflects the maximum hourly heat input for each of the boiler. The value does not account for the permitted annual coal consumption limit. If the coal consumption limit is considered, the maximum hourly heat input is reduced to 583 MMBtu/hr averaged over a year. A reduction in hourly heat input will have an impact on the overall cost effectiveness calculation, but given the concerns with the calculation itself, identifying the specific impacts is difficult.

- SO_2 Emission Rates: The preliminary BACT determination states that the SO_2 emission rate used in the spreadsheet to calculate the total annualized operating costs was based on 0.2 weight percent (wt. pct.) sulfur coal and AP-42 emission factors. This approach resulted in an emission rate of 0.46 pounds of SO_2 per MMBtu (lb SO_2/MMBtu) heat input. This value is significantly different than the effective emission rate for the plant based on the PTE established in Title V Permit AQ1121TVP02, Revision 2. The effective emission rate is calculated as follows:

  Permitted PTE: 1,764 tons of SO_2
  Permitted coal consumption limit: 336,000 tpy
  Assumed coal energy content: 7,600 British thermal units per pound (Btu/lb)

1,764 tons SO_2/yr * 1 year/336,000 tons coal * 1 lb coal/7,600 Btu * 10^6 Btu/MMBtu * 1 ton coal/2,000 lb coal * 2,000 lb SO_2/ton
= 0.691 lb SO_2/MMBtu

The difference between the ADEC-assumed emission rate and the effective emission rate leads to a significant error in the SO_2 cost effectiveness calculation. The ADEC spreadsheet divides the total annualized cost (determined by using the 0.46 lb/MMBtu SO_2 rate) by the SO_2 PTE (with an effective rate of 0.691 lb/MMBtu). The use of two different emission rates in this calculation results in an invalid comparison of two values that should not be compared to each other. For the result of the equation to be valid, the total annualized cost must be calculated using an SO_2 emission rate equal to the SO_2 PTE.

- Conclusion: Based on the review of the preliminary SO_2 BACT determination and the associated cost effectiveness calculation, no indication could be found that the Preliminary Determination calculation accurately reflects the actual operating conditions for EUs 1 through 6. As a result, no basis exists for determining if the installation of a DSI system is or is not economically feasible. Despite the inability to determine the accuracy of the calculations in the Preliminary Determination, those calculations likely underestimate the DSI cost effectiveness because the Preliminary Determination underestimates SO_2 emissions on a lb/MMBtu basis.

  If a more accurate cost effectiveness is to be determined, the cost effectiveness should be recalculated using a bottom-up cost estimating approach based on actual plant conditions. These conditions would include SO_2 emission rates based on current PTE, permit constraints (where applicable and enforceable), available space, ambient conditions, and local factors such as construction logistics, labor wage rates, and local sorbent costs.

21. Section 5.1 (Industrial Coal-fired Boilers), Step 5: The proposed coal combustion limit of 300,000 tpy and the assumption that the coal sulfur content is no greater than 0.2 weight percent are not evaluated through the five-step BACT process, or even identified as available control technologies in Step 1.
    - The current coal combustion limit for the six boilers is 336,000 tpy, per Condition 12.1 of AQ1121TVP02, Revision 2.
    - The current coal sulfur content is not limited beyond the State SIP SO_2 standard and the requirement to determine what the SO_2 emission concentrations would be prior to combusting coal with a sulfur content of greater than 0.4 weight percent. (Refer to Conditions 11 and 11.1 of AQ1121TVP02, Revision 2.)
    - If either of these requirements is to be imposed as a limit without a BACT analysis justifying the limit, the limit(s) should be used to calculate a revised baseline emission rate. The BACT analysis should then calculate any further emission reductions based on that revised baseline emission rate.

    DU does not agree that either the coal consumption limit of 300,000 tpy or the coal sulfur content assumption of less than or equal to 0.2 weight percent is appropriate. More investigation is needed to determine whether these assumptions are valid and feasible. At the least, the 0.2 weight percent coal

sulfur limit should be assessed through the BACT analysis process. DU is not aware that Usibelli Coal Mine, the sole supplier of coal in Alaska, has even been contacted to advise whether the mine is capable of providing coal meeting that specification on a long-term basis. Step 1(d) of the Preliminary Determination acknowledges that the current contract guarantee is less than 0.4 weight percent sulfur, and that the coal typically ranges from 0.08 to 0.28 weight percent sulfur.

22. Section 5.4 (Small Emergency Engines), Step 5(a): The requirement to limit non-emergency operation of small emergency engines is inconsistent with applicable requirements under 40 CFR 63 Subpart ZZZZ (or Subpart IIII, if applicable), which allows 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing.

23. Section 5.4 (Small Emergency Engines), Step 5(b): The determination that good combustion practices is BACT should be eliminated or a rationale should be provided for selecting good combustion practices in addition to the combustion of ULSD and limited operations. Per Table 5-10 of the Preliminary Determination, good combustion practices were not determined to be SO_2 BACT for small diesel-fired engines at other stationary sources. While DU follows good combustion practices as a standard practice, Step 3(c) indicates that good combustion practices are the least effective SO_2 emission control technology.

Attachment: EPA comments on ADEC Preliminary Draft Serious SIP Development materials for the Fairbanks serious $PM_{2.5}$ nonattainment area

General

The attached comments are intended to provide guidance on the preliminary drafts of SIP documents in development by ADEC. We expect that there will be further opportunities to review the more complete versions of the drafts and intend to provide more detailed comments at that point

1. Statutory Requirements - This preliminary draft does not address all statutory requirements laid out in Title I, Part D of the Clean Air Act or 40 C.F.R. Part 51, Subpart Z. The submitted Serious Area SIP will need to address all statutory and regulatory requirements as identified in Title I, Part D of the Clean Air Act, 40 C.F.R. Part 51, Subpart Z, the August 24, 2016 $PM_{2.5}$ SIP Requirements Rules (81 FR 58010, also referred to at the $PM_{2.5}$ Implementation Rule), and any associated guidance.

   In the preliminary drafts, notable missing elements included: Reasonable Further Progress, Quantitative Milestones, and Conformity. This is not an exhaustive list of required elements.

   The NNSR program is a required element for the serious area SIP. We understand ADEC recently adopted rule changes to address the nonattainment new source review element of the Serious SIP, and that ADEC plans to submit them to the EPA separately in October 2018. Thank you for your work on this important plan element.

2. Extension Request - This preliminary draft does not address the decision to request an attainment date extension and the associated impracticability demonstration. On September 15, 2017, ADEC sent a letter notifying the EPA that it intends to apply for an extension of the attainment date for the Fairbanks $PM_{2.5}$ Serious nonattainment area. The Serious Area SIP submitted to EPA will need to include both an extension request and an impracticability demonstration that meet the requirements of Clean Air Act section 188(e). In order to process an extension request, the EPA requests timely submittal of your Serious Area SIP to allow for sufficient time to review and take action prior to the current December 2019 attainment date, so as to allow, if approvable, the extension of the attainment date as requested/appropriate. For additional guidance, please refer to 81 FR 58096.

3. Split Request - We support the ADEC and the FNSB's decision to suspend their request to the EPA to split the nonattainment area. We support the effort to site a monitor in the Fairbanks area that is more representative of neighborhood conditions and thus more protective of community health. This would provide additional information on progress towards achieving clean air throughout the nonattainment area.

4. BACM (and BACT), and MSM - Best Available Control Measures (including Best Available Control Technologies) and Most Stringent Measures are evaluative processes inclusive of steps to identify, adopt, and implement control measures. Their definitions are found in 51.1000, 51.1010(a).

All source categories, point sources – area sources – on-road sources – non-road sources, need to be evaluated for BACM/BACT and MSM. De minimis or minimal contribution are not an allowable rationale for not evaluating or selecting a control measure or technology.

The process for identifying and adopting MSM is separate from, yet builds upon, the process of selecting BACM. Given that Alaska is intent on applying for an extension to the attainment date, Alaska must identify BACM and MSM for all source categories. These processes are described in 51.1010(a) and 51.1010(b) and in the $PM_{2.5}$ Implementation Rule preamble at 81 FR 58080 and 58096. We further discuss this process in the "BACM (and BACT), MSM" section that starts on page 3 below.

5. Resources and Implementation - The serious area $PM_{2.5}$ attainment plan will be best able to achieves its objectives when all components of the SIP, both the ADEC statewide and FNSB local measures, are sufficiently funded and fully implemented.

6. Use of Consultants- For the purpose of clarity, it will be important to identify that while contractors are providing support to ADEC, all analyses are the responsibility of the State.

Emissions Inventory

1. Extension Request Emission Inventories - Emissions inventories associated with the attainment date extension request will need to be developed and submitted. Table 1 of the Emissions Inventory document is one example where the submittal will need to include the additional emissions inventories, including RFP inventories, extension year inventories for planning and modeling, and attainment year planning and modeling inventories, associated with the attainment date extension request.

2. Modeling Requirements - Related to emissions inventory requirements, the serious area SIP will need to model and inventory 2023 and 2024, at minimum. We recommend starting at 2024 and modeling earlier and earlier until there is a year where attainment is not possible. That would satisfy the requirement that attainment be reached as soon as practicable.

3. Condensable Emissions - All emissions inventories and any associated planning, such as Reasonable Further Progress schedules, need to include condensable emissions as a separate column or line item, where available. Where condensable emissions are not available separately, provide condensable emissions as included (and noted as such) in the total number. The following are examples of where this would need to be incorporated in to the Emissions Inventory document:
    a. Page 20, paragraph 5 (or 2nd from the bottom).
    b. Page 34, Table 8. Include templates.

Precursor Demonstration

1. Ammonia Precursor Demonstration - The draft Concepts and Approaches document, Table 4 on page 9, states that a precursor demonstration was completed for ammonia and that the result was "Not significant for either point sources or comprehensively." The Precursor Demonstration chapter does not include an analysis for ammonia. Please include the precursor demonstration for ammonia in the Serious Plan or amend this table.

2. Sulfur Dioxide Precursor Description - The draft Concepts and Approaches document, Table 4 on page 9, states that sulfur dioxide was found to be significant. All precursors are presumptively considered significant by default and the precursor demonstration can only show that controls on a precursor are not required for attainment. Suggested language is, "No precursor demonstration possible."

BACM (and BACT), MSM

Overall

The EPA appreciates ADECs efforts to identify and evaluate BACM for eventual incorporation into the Serious Area SIP. The documents clearly display significant effort on the part of the state and are a good first step in the SIP development process. In particular, we are supportive of ADECs efforts to evaluate BACT for the major stationary sources in the nonattainment area, as control of these sources is required by the CAA and $PM_{2.5}$ SIP Requirements Rule.

1. BACM/BACT and MSM: Separate Analyses - The "Possible Concepts and Potential Approaches" document appears to conflate the terms BACM/BACT and MSM, as well as, the analyses for determining BACM/BACT and MSM. BACM and MSM have separate definitions in 40 CFR 51.1000. By extension, the processes for selecting BACM and MSM are laid out separately in the $PM_{2.5}$ SIP Requirements Rule (compare 40 CFR 51.1010(a) for BACM and 40 CFR 51.1010(b) for MSM). Accordingly, the serious area SIP submission will need to have both a BACM/BACT analysis and an MSM analysis. We believe that there is flexibility in how these analyses can be presented, so long as the submission clearly satisfies the requirements of both evaluations, methodologies, and findings.

2. Selection of Measures and Technologies - The CAA and the $PM_{2.5}$ SIP Requirements Rule requires that ***all*** available control measures and technologies that meet the BACM (including BACT) and MSM criteria need to be implemented. All source categories need to be evaluated including: point sources (including non-major sources), area sources, on-road sources, and non-road sources.

3. Technological Feasibility - All available control measures and technologies include those that have been implemented in nonattainment areas or attainment areas, or those potential measures and technologies that are available or new but not yet implemented. Similarly, Alaska may not automatically eliminate a particular control measure because other sources or nonattainment areas have not implemented the measure. The regulations do not have a quantitative limit on number of controls that should be implemented.

For technological feasibility, a state may consider factors including local circumstances, the condition and extent of needed infrastructure, or population size or workforce type and habits, which may prohibit certain potential control measures from being implementable. However, in the instance where a given control measure has been applied in another NAAQS nonattainment area, the state will need to provide a detailed justification for rejecting any potential BACM or MSM measure as technologically infeasible (81 FR 58085).

A Borough referendum prohibiting regulation of home heating would not be an acceptable consideration to render potential measures technologically infeasible. The State would be responsible for implementing the regulations in the case that the Borough was not able. We believe that the most efficient path to clean air in the Borough is through a local, community effort.

4. Economic Feasibility - The BACM (including BACT) and MSM analyses need to identify the basis for determining economic feasibility for both the BACM and MSM analyses. In general, the $PM_{2.5}$ SIP Requirements Rule requires the state apply more stringent criteria for determining the feasibility of potential MSM than that used to determine the feasibility of BACM and BACT, including consideration of higher cost/ton values as cost effective.

5. Timing - The evaluations will need to identify the time for selection, adoption, and implementation for all measures. BACT must be selected, adopted, and implemented no later than 4 years after reclassification (June 2021). MSM must be selected, adopted, and implemented no later than 1 year prior to the potentially extended attainment date (December 2023 at latest). The RFP section of the serious area plan will need to identify the BACM and MSM control measures, their time of implementation, and the time(s) of expected emissions reductions. Timing delays in selection, adoption, implementation are not considered for BACM and MSM.

   As mentioned in the comment above in the "General" comment section, there are three criteria distinguishing between BACM and MSM, not one.

BACM - General

1. BACM definition, evaluations - The definition of BACM at 40 CFR 51.1000 describes BACM as any measure "that generally can achieve greater permanent and enforceable emissions reductions in direct $PM_{2.5}$ and/or $PM_{2.5}$ plan precursors from sources in the area than can be achieved through the implementation of RACM on the same sources." We believe that potential measures that are no more stringent than existing measures already implemented in FNSB, those that do not provide additional direct $PM_{2.5}$ and/or $PM_{2.5}$ precursors emissions reductions, do not meet the definition of BACM. These would need to be evaluated in the BACM and MSM analysis.

   For measures that are currently being implemented in Fairbanks that provide equivalent or more stringent control, we recommend identifying the ADEC or Borough implemented measure as part of the BACM control strategy. These implemented measures should be listed in their BACM findings at the end of the document. This comment applies to all of the

measures that were screened out from consideration due to not being more stringent than the already implemented measure.

The analyses for a number of measures (e.g., Measure 30, Distribution of Curtailment Program information at time of woodstove sale) conclude that the emission reductions would be insignificant and difficult to quantify and, therefore, the measure is not technologically feasible. These measures may be technologically feasible. However, if existing measures constitute a higher level of control or if implementation of the measures is economically infeasible those would be valid conclusions if properly documented. De minimis or minimal contribution is not a valid rationale for not considering or selecting a control measure or technology.

The conclusion "not eligible for consideration as BACM" is not valid as all assessments for BACM and MSM are part of the evaluation. More appropriate conclusions could include that existing measures qualify as BACM or MSM, or are more stringent. Additional conclusions could include that evaluated measures were not technologically feasible, economically feasible, or could not practically be adopted and implemented prior to the required timeframe for BACM or MSM.

2. BACM and MSM, Ammonia - In the Approaches and Concepts document, Table 5 references that there are no applicable control measures or technologies for the $PM_{2.5}$ precursor ammonia. No information to substantiate this claim are found in the preliminary draft documents. Unless NH_3 is demonstrated to be insignificant for this area, the serious area plan will need to include an evaluation of NH_3 and potential controls for all source categories including points sources.

3. Backsliding Potential - When benchmarking the BACM and MSM analyses for stringency, ensure that the evaluation is based on the measures approved into the current Moderate SIP. This will relate primarily to the current ADEC/FNSB curtailment program but also other related rules. Many wood smoke control measures are interrelated, and changes to those measures may affect determinations on stringency of directly related and indirectly related measures. Examples of this can be found in multiple measures including, but not limited to Measures 5, 7, and 16.

4. Transportation Control Measures - The Approaches and Concepts document, on Page 13, states that the MOVES2014 model does not estimate a PM benefit as a result of an I/M program, and therefore the I/M is not technologically feasible. This is not a valid conclusion given that the Fairbanks area operated an I/M program to reduce carbon monoxide and the Utah Cache Valley nonattainment areas has an I/M program for VOC control. This measure will need to be evaluated. Referring to the 110(l) analysis for the Fairbanks CO I/M program may provide insight into how to quantify the emissions associated with an I/M program.

With regard to control measures related to on-road sources, we have received inquiries from the community regarding idling vehicles and further evaluation emission benefits would be responsive to citizen concern and may provide additional air quality benefit.

BACM - Specific Measures

- Measure 16, page 34-35. Date certain Removal of Uncertified Devices. The "date certain" removal of uncertified woodstoves in Tacoma, Washington appears more stringent than the current Moderate SIP approved Fairbanks ordinance in terms of the regulation and in practice. While the current ordinance appears to provide similar protection during stage 1 alerts, this is dependent on 100% compliance and the curtailment program remaining in its current form. Removal of uncertified stoves guarantees reductions in emissions in the airshed during both the curtailment periods and throughout the heating season. The information provided does not support the conclusion that the Fairbanks controls provides equivalent or more stringent control. Date certain removal of uncertified wood stoves needs to be considered for the area.

  Measures R4, R9, and R12, page 64, 68 and 71. These measures do not reference the Puget Sound Clean Air Agency (Section 13.07) requirement for removal of all uncertified stoves by September 30, 2015. This is equivalent to having all solid fuel burning appliances be certified and would be more stringent than the current SIP approved rules in Fairbanks. We believe that these measures need to be evaluated in the BACM and MSM analyses.

  Measure R4 and R9, page 64 and 68. All Wood Stoves Must be Certified. These measure should be evaluated.

- Measure 19-20 and 25, page 36-38 and 39. Renewal and Inspection Requirements. ADEC has not adequately demonstrated their conclusion that Fairbanks has a more stringent measure than Missoula and San Joaquin. We believe that the renewal requirements and inspection/maintenance requirements associated with the Missoula alert permits and San Joaquin registrations allows the local air agency an opportunity to verify on a regular basis that the device operates properly over times. Wood burning appliances require regular maintenance in order to achieve the certified emissions ratings. The FNSB Stage 1 waivers do not have an expiration and do not have an inspection and maintenance component making it less stringent.

- Measure 31, page 43. While the Borough has SIP approved dry wood requirements that prohibit the burning of wet wood and moisture disclosure requirements by sellers, we believe that a measure limiting the sale of wet wood during the winter months should be further analyzed for BACM (and MSM) consideration.

- Measures 33, 35, 36, 37, 43. Multiple Measures identify that recreational fires have been exempted from existing regulations. Small unregulated recreational fires, bonfires, fire pits,

and warming fires have the potential to contribute emissions during a curtailment period. The FNSB and ADEC regulations should be re-evaluated for removing this exclusion.

- Measure 49, page 58. Ban on Coal Burning. We believe the regulations in Telluride are more stringent than in Fairbanks. Telluride prohibits coal burning all year whereas in Fairbanks an existing coal stove can burn when there is no curtailment which could contribute additional emissions to the airshed, especially during poor conditions when a curtailment may not have been called. We do not agree with the conclusion that the PM_{10} controls are ineligible for consideration for control of $PM_{2.5}$.

- Measure R20, page 76. Transportation Control Measures related to Vehicle Idling. We have received multiple inquiries regarding community interest in controlling emissions from idling vehicles. These types of control measures should be further evaluated in the BACM and MSM analyses.

- Measure 1, page 79-81. Surcharge on Solid Fuel Burning Appliances. For purposes of implementing an effective program to reduce $PM_{2.5}$ in the Borough we believe that a surcharge may be a helpful way to supplement limited funds. Implementation efforts within the nonattainment area could benefit from $24,000 of additional funding whether used for a code enforcer or other support of the wood smoke programs.

- Additional controls that should be further evaluated for BACM and MSM include:
    - Measure R1, page 63: Natural gas fired kiln or regional kiln.
    - Measure R12, page 71: Replace uncertified stoves in rental units.
    - Measure R17, page 75: Ban use of wood stoves
    - Measure R6, page 65: Remove Hydronic Heaters at Time of Home Sale & Date certain removal of Hydronic heaters. We suggest evaluating these measures at the state and local level.
    - Weatherization / heat retention programs should be evaluated. These should be evaluated for existing homes through energy audits and increasing insulation and energy efficiency. For new construction, building codes (Fairbanks Energy Code) should be evaluated with reference to the IECC Compliance Guide for Homes in Alaska http://insulationinstitute.org/wp-content/uploads/2015/12/AK_2009.pdf, and the DOE R-value recommendations, http://www.fairbanksalaska.us/wp-content/uploads/2011/07/ENERGY-CODE.pdf. (Note: More recent information may be available.)
    - Fuel oil boiler upgrades / operation & maintenance programs should be evaluated.

BACM - Ultra-Low Sulfur Fuel

1. Incomplete Analysis - The report findings provide analysis of the demand curve over a relatively short (12 month) time frame. This analysis appears to be based on a partial equilibrium model. This is a misleading time frame given the volatility of demand side fuel oil pricing. Also, in order to determine the equilibrium price, the analysis must also analyze

the supply curve. The report does not include information about the future supply side costs but needs to in order to make conclusions about the cost to the community of ultra-low sulfur heating oil.

2. Analysis of Increased Supply, Consumption - The report does not address future change in the market nor potential economies of scale to be achieved by an increase in ultra-low sulfur fuel consumption. Page 3 of the report identifies that, "the additional premium to purchase ULS over HS, decreased significantly since 2008-2010. It is likely that, this can be attributed to increased ULS capacity." We believe that the report should further explore the supply side costs.

3. Supply Cost Analysis - A supply side cost analysis is necessary to better understand the cost to the supplier to produce and provide ULS heating fuel. The BACM analysis must start with a transparent and detailed economic analysis of exclusively supplying ultra-low sulfur heating oil to the nonattainment area.

4. BACM Assessment - The current analysis does not provide information needed to assess BACM economic feasibility. The report should analyze the total cost to industry of delivering ultra-low sulfur heating oil to the entire community in terms of standard BACM metrics, $/ton.

BACT

General Comments

At this time, EPA is providing general comments based on review of the draft BACT analyses prepared by ADEC as well as addressing certain issues discussed in earlier BACT comments provided by EPA. Detailed comments regarding each individual analysis are not being provided at this time. While EPA appreciates the time and effort invested by ADEC staff in preparing the draft BACT analyses, the basic cost and technical feasibility information needed to form the basis for retrofit BACT analyses at the specific facilities has not been prepared. In other words, analyses which are adequate to guide decision making regarding control technology decisions for these rather complex retrofit projects cannot be prepared without site specific evaluation of capital control equipment purchase and installation costs, and site specific evaluation of retrofit considerations. EPA will conduct a thorough review of any future BACT or MSM analyses which are prepared based on adequate site specific information, and will provide detailed comments relative to each emission unit and pollutant at that time.

1. Level of Analysis – The analyses are presented as "preliminary BACT/MSM analyses" on the website, but the documents themselves are titled only as BACT analyses and the conclusions only reflect BACT. Additionally, the determinations may not be stringent enough to be considered BACT given that better performing SO_2 control technologies have not been adequately analyzed. These analyses cannot be considered to provide sufficient basis to support a selection of MSM.
2. Site-Specific Quotes Needed – The cost analyses, particularly for SO_2 control technologies, must be based on emission unit-specific quotes for capital equipment purchase and

installation costs at each facility. These are retrofit projects which must be considered individually in order to obtain reliable study/budget level (+/- 30%) cost estimates which are appropriate to use as the basis for decision making in determining BACT and potentially MSM. EPA believes that control decisions of this magnitude justify the relatively small expense of obtaining site-specific quotes.

3. SO_2 Control Technologies – The analyses must include evaluation of circulating dry scrubber (CDS) SO_2 control technology. This demonstrated technology can achieve SO_2 removal rates comparable to wet flue gas desulfurization (FGD) at lower capital and annual costs, and is more amenable to smaller units and retrofits. Modular units are available.
4. Control Equipment Lifetime – The analyses must use reasonable values for control equipment lifetime, according to the EPA control cost manual (EPA CCM). EPA believes that the following equipment lifetimes reflect reasonable assumptions for purposes of the cost analysis for each technology as stated in the EPA control cost manual and other EPA technical support documents. Use of shorter lifetimes for purposes of the cost analysis must include evidence to support the proposed shortened lifetime. One example where EPA agrees a shortened lifetime is appropriate would be where the subject emission unit has a federally enforceable shutdown date. Certain analyses submitted in the past have claimed shortened equipment lifetimes based on the harshness of the climate in Fairbanks. In order to use an equipment life that is shortened based on the harsh climate, evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers. Lacking adequate justification, all cost analyses must use the following values for control equipment lifetime:
    a. SCR, Wet FGD, DSI, CDS, SDA – 30 years
    b. SNCR – 20 years
5. Availability of Control Technologies – Technologically feasible control technologies may only be eliminated based on lack of availability if the analysis includes documented information from multiple control equipment vendors (who provide the technology in question) which confirms the technology cannot be available within the appropriate implementation timeline for the emission unit in question.
6. Assumptions and Supporting Documents – All documents cited in the analyses which form the basis for costs used and assumptions made in the analyses must be provided. Assumptions made in the analyses must be reasonable and appropriate for the control technologies included in the cost analysis.
7. Interest Rate – All cost analyses must use the current bank prime interest rate according to the revised EPA CCM. As of May 10, 2018, this rate is 4.75%. See https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table).
8. Space Constraints – In order to establish a control technology as not technologically feasible due to space constraints or other retrofit considerations, detailed site specific information must be submitted in order to establish the basis for such a determination, including detailed drawings, site plans and other information to substantiate the claim.
9. Retrofit Factors – All factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor or whether installation of a specific control technology is technologically infeasible. EPA Region 10

believes that installation factors which would complicate the retrofit installation of the control technology should be evaluated by a qualified control equipment vendor and be reflected in a site-specific capital equipment purchase and installation quote. Lacking site-specific cost information, all factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor. One example of the many retrofit considerations that must be evaluated is the footprint required for each control technology. A vendor providing a wet scrubber will be able to estimate the physical space required for the technology, and evaluate the existing process equipment configuration and available space at each subject facility. The determination of whether a specific control technology is feasible and what the costs will be may be different at each facility based on this and other factors. Site-specific evaluation of these factors must be conducted in order to provide a reasonable basis for decision making.

10. Control Efficiency – Cost effectiveness calculations for each control technology must be based on a reasonable and demonstrated high end control efficiency achievable by the technology in question at other emission units, or as stated in writing by a control equipment vendor. If a lower pollutant removal efficiency is used as the basis for the analysis, detailed technical justification must be provided. For example, the ability of SCR to achieve over 90% NO_X reduction is well established, yet the ADEC draft analyses assume only 80% control. Use of this lower control efficiency requires robust technical justification.
11. Condensable Particulate Matter – Although the existing control technology on the coal fired boilers may be evaluated as to whether it meets the requirement for BACT for particulate matter, baghouses primarily reduce emissions of filterable particulate matter rather than condensable PM. Given that all condensable PM emitted by the coal fired boilers would be classified as $PM_{2.5}$, the BACT analyses must include consideration of control options for these emissions. Where control technologies evaluated for control of other pollutants may provide a collateral benefit in reducing emissions of $PM_{2.5}$, this should be evaluated as well.
12. Guidance Reference – The steps followed to perform the BACT analysis mentioned in section 2 are from draft NSR/PSD guidance. The correct reference should be 81 FR 58080, 8/24/2016. As a result of this, some of the steps outlined in the BACT analysis need to be updated.
13. Community Burden Estimate – The concepts and approaches document labels capital purchase and installation costs for air pollution control technology at the major source facilities as "community burden" (see Tables 7 and 8, pages 10-11). EPA believes it is important to properly label the cost numbers being used as capital purchase and installation costs, since presenting them as community burden appears to attribute the entire initial capital investment for the various control technologies to the community in a single year, and also ignores annual operation and maintenance costs. As described in the EPA CCM, the cost methodology used by EPA for determining the cost effectiveness of air pollution control technology amortizes the initial capital investment over the expected life of the control device, and includes expected annual operating and maintenance expenses. EPA believes presentation of this annualized cost over the life of the control technology more accurately represents the actual cost incurred and is consistent with how cost effectiveness is estimated in the context of a BACT analysis.
14. Conversion to Natural Gas – For any emission units capable of converting to natural gas combustion (with the requisite changes to the burners, etc), the MSM analysis in particular

should thoroughly evaluate the feasibility of this option. For example, GVEA has stated the combustion turbines at its North Pole Expansion Power Plant have the ability to burn natural gas, and the IGU has indicated the intent to expand the supply of natural gas to Fairbanks and North Pole.

APPENDIX:

Additional Comments and Suggestions

Possible Concepts and Potential Approaches

Throughout all SIP documents references to design values should include a footnote to the source of the information (e.g., "downloaded from AQS on XX/XX/XXX" or "downloaded from [state system] on XX/XX/XXXX") and how exceptional events were treated.

We suggest referencing the August 24, 2016 81 FR 58010 Fine Particulate Matter NAAQS: State Implementation Plan Requirements rule with one consistent term. We suggest the 2016 $PM_{2.5}$ Implementation Rule.

Page 4, Figure 1. The comparative degree days and heating related information is better suited for the sections evaluating BACM and economic feasibility. If intending on using this information to differentiate Fairbanks from other cold climates and/or nonattainment areas, depicting comparative home heating costs would be more supportive.

Page 4, Table 1. The design values in the table and in the discussion need to be updated for 2015-2017.

Page 6-7: The "Totals" row in Table 3 (non-attainment areas emissions by source sector) does not appear to be the sum of the individual source sector emissions.

Page 7: The statement about FNSB experiencing high heating energy demand per square foot needs to be referenced.

Page 7: The discussion of Eielson AFB growth needs a reference to the final EIS.

Page 9: Table 4's title should be changed to "Preliminary Precursor Demonstration Summary"

Page 9: Table 4 includes a column "Modeling Assessment". Not all precursors were assessed with modeling, and modeling is just one tool for the precursor demonstration. A suggestion for the column title is "Result of Precursor Demonstration."

Page 9: Table 5's title should be changed to "Preliminary BACT Summary." Table 5 also needs to update the title to reference "Precursor Demonstration" as the term "Precursor Significance Evaluation" is the incorrect terminology for this analysis.

Page 10: ADEC's proposal to only require one control measure per major stationary source to meet BACT and MSM for SO_2, is not consistent with the Act or rule. As discussed above, BACM and MSM have separate definitions in 40 CFR 51.1000. By extension, the processes for

selecting BACM and MSM are laid out separately in the PM2.5 SIP Requirements Rule (compare 40 CFR 51.1010(a) for BACM and 40 CFR 51.1010(b) for MSM).

Page 10: Table 6 should identify the specific dry sorbent injection selected as BACT.

Page 11: Suggest changing “less sources” to “fewer sources.”

Page 13: The statement about an I/M program providing PM benefit needs to be clarified. Is this referring just to NOx and VOC precursor contribution to PM2.5, or also direct PM2.5 benefits?

Page 14: The statement “ADEC interprets the main difference between BACT/BACM and MSM as the time it takes to implement a control” is inaccurate. As discussed above, although the rule sets our different schedules for implementation of MSM and BACM, this is not the only major difference between those concepts. Notably, the rule contemplates a higher stringency for MSM as well as a higher cost/ton threshold for determining economic feasibility of the measure.

Technical Analysis Protocol

Page 2: The design values at the top of the page need to be updated to 2015-2017.

Page 2: Recommend removing the sentence “This site will be included in the Serious SIP’s attainment plan…” as the North Pole Elementary will be involved in the redesignation to attainment in the sense that all past and current monitoring data will be a part of an unmonitored area analysis to show that the entire area has attained the standard in addition to the regulatory monitor locations.

Page 2: Remove the discussion of the nonattainment area split.

Page 2: Paragraph 2, sentence 3 should refer to the unmonitored area analysis.

Page 2: The timeline described at the bottom of the page needs to be modified to reflect a current schedule. No projected year modeling was included in the preliminary draft documents. Control scenario modeling will likely not be completed in Q2 2018.

Page 3: We suggest a sentence overview of the unmonitored area analysis in Section 3.1.

Page 3: Section 3.2 needs to refer to the SPM data and how that will be used in the Serious Plan unmonitored area analysis. This section should discuss current DEC efforts to site a new monitor in Fairbanks.

Page 3: Section 3.4 needs to describe the CMAQ domain in addition to the WRF domain. A figure (map) would help.

Page 4: Section 3.5 needs a more developed discussion of the WRF assessment, including describing the criteria that were used to assess the state-of-the-art, what the current version is, and what version was used.

Page 4: Section 3.6 needs to reference all emission inventories in development, including potential attainment date extension years and RFP years.

Page 4: In Section 4.1, the statement about the Moderate SIP covering the relevant monitors for the Serious SIP is inaccurate. The statement needs to qualify whether it is referring to regulatory monitors or non-regulatory monitors. In addition, the North Pole Fire Station, NCore, and North Pole Elementary monitors were not included in the Moderate SIP.

Page 5: Table 4.1-1's title suggests that all SPM sites are listed, but only sites with regulatory monitors are listed. Please list all the SPM sites used in the unmonitored area analysis in a separate table and modify this title of Table 4.1-1 to reflect that it lists sites that are regulatory.

Page 5: North Pole Elementary was a regulatory site for a part of the baseline period and was NAAQS comparable. Table 4.1-1 needs to be updated.

Page 8: Table 4.2-1 should be updated to include 2011-2017 98^{th} percentiles. Table 4.2-2 should be updated to include 3-year design values for 2013-2017. For clarity, we recommend the 3-year design values include the full period in order to better distinguish from Table 4.2-1. For instance, "2013" would be "2011-2013".

Page 8: The statement starting, "a clear indication…" needs to be amended or removed. It is inaccurate. The prevalence of organic carbon does not indicate the dominance of wood burning, much less a clear indication. Many sources in Fairbanks emit organic carbon.

Page 8: The statement starting "The concentration share…" need to be amended or removed. Suggest removing "drastically". There is no scientific definition of a drastic change in percentages of $PM_{2.5}$ species, nor does the different 56% to 80% appear "drastic."

Page 9: The detailed description of the Simpson and Nattinger analysis does not reflect that SANDWICH process and it is preliminary data. It should be included within the body of the Serious Plan appendix on monitoring, but is out of place in a summary TAP.

Page 9: there are two different tables with the same table number (Table 4.3-1).

Page 10: Please clarify Table 4.4-1. This appears to be the design value calculation for the 5-year baseline design value, 2011-2015. If correct, then please label the 3-year design values according to the three years (e.g., "2011-2013"), clarify the table heading as being the "Five Year Baseline Design Value, 2011-2015 (µg/m3)", and clarify that the last column is the 5 Year Baseline Design Value associated with the table heading.

Page 11: At the end of section 5, please refer to the emission inventory chapter's meteorological discussion of the episodes.

Page 11: Section 6 needs to justify the extent, resolution, and vertical layer structure of the CMAQ domain (and the WRF domain) or refer to where that is included in the Moderate Plan.

Page 13: We suggest changing "PMNAA" to "NAA" to be consistent with the EI chapter.

Page 15, Section 8.1: There needs to be mention of how the F-35 deployment will be considered, with a reference to the final EIS.

Page 15-19: section 8.2-8.6 use the future tense for tasks that have been completed and are inconsistent with the schedule at the beginning of the TAP. Please adjust based on current status.

Page 20, section 9.2 states that "a BACT analysis is an evaluation of all technically available control technologies for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts." This sentence should be revised to reflect that the technological feasibility assessment occurs after identification of all potential control measures for each source and source category.

Page 20, section 9.3 the second sentence should read: "BACM measures found to be economically infeasible for BACM *must* be analyzed for MSM."

Page 21: Section 10.1 needs to be updated to reflect the current CMAQ version (5.2.1) and a discussion of why that model has not been used.

Page 21: Suggest sentence starting "There will be a gap…" be changed to "There is a gap in terms of assessing the performance at the North Pole Fire Station monitor for the Serious Plan because the State Office Building in Fairbanks was the only regulatory monitor at the time of the 2008 base case modeling episodes."

Page 23: Please explain the solid and dashed lines in the soccer plot.

Page 23: Please be sure to include a full discussion of North Pole performance in this section. Even though we lack measurements, we can discuss the ratio of the modeling results at NPFS versus SOB versus that ratio from more recent monitoring data (2011-2015 baseline design value period).

Page 23: Please clarify what is meant by "Moderate Area SIP requirements."

Page 24: The discussion of the 2013 base year discusses representative meteorological conditions without describing what the representative meteorological conditions are for high $PM_{2.5}$. Please reference the discussion of representative meteorological conditions that will be found elsewhere in the SIP.

Page 24: The discussion of the modeling years needs to be consistent and reflect the extension request past 2019. The attainment year cannot be earlier than 2019. Each extension year must be individually requested. For modeling efficiency, we recommend starting with 2024. If that year attains, then 2023 and so on until we have one year that attains and the year before that does not. This should give us the information about what is the earliest year for attainment.

Page 25: We suggest changing "modeling design value" to "design value for modeling"

Page 26: Please clarify the "SMAT" label in the tables. They may be the SANDWICH concentrations and the "5-yr DV" rows are the SMAT concentrations. Please clarify the units in the rows.

Emission Inventory

Clarification – In the EI document we would like to understand the functional difference between the base year, and baseline year

Please identify the methodology for generating ammonia and condensable PM emissions numbers.

Page 1: Please be consistent in “emission inventory” versus “emissions inventory”.

Page 1: “CAA” to “Clean Air Act” for clarity

Page 3: It would be helpful to refer to 172(c)(3) in Section 1.2, bullet 1 as the planning and reporting requirements.

Page 5: Please include extension years and RFP years in Table 1’s calendar years similar to what was done for Table 2. There should be one RFP projected inventory and QM beyond the extended attainment date. It would be helpful to include basic information about extension years and RFP years to better foreshadow Table 2.

Page 7: Please clarify the “winter season” inventory as the “seasonal” inventory that represents the daily average emissions across the baseline episodes.

Page 7, paragraph 1. Please include reference documentation for the following statement, “results in extremely high heating energy demand per square foot experienced in no other location in the lower-48.”

Page 9: Please change “Violations” to “Exceedances.” Exceedance is the term for concentrations over the standard. Violations is the term for dv over the standard.

Page 9: Add “No exceedances were recorded outside the months tabulated in Table 3 that were not otherwise flagged by Alaska DEC as Exceptional Events.”, to the end of the last paragraph on the page.

Page 13: Please clarify the provenance of the BAM data (e.g., “downloaded from [state database or AQS] on XX/XX/XXXX). In particular, it is important to note if the data has been calibrated to the regulatory measurement (aka, corrected BAM).

Page 17-18. Sentence Unclear “For example, a planning inventory based on average daily emissions across the entire six-month nonattainment season will likely reflect a relatively lower fraction of wood use-based space heating emissions than one based on the modeling episode day average since wood use for space heating Fairbanks tends to occur as a secondary heating source on top of a “base” demand typically met by cleaner home heating oil when ambient temperatures get colder.”

Page 19: Remove “Where appropriate,”. All source sectors should be re-inventoried for 2013, even if the emissions for the sector ends up being the same as in 2008.

Page 19: Change “projected forward” to “re-inventoried”, or similar wording. Reserve “project” for when the emission inventory is estimating emissions in a future year.

Page 20: Please refer to EPA’s memo on the use of MOVES2014a for the plug in adjustment. As a reminder, this information is sufficient only for development of the emissions inventory, not for SIP credit.

Page 20: Please submit the technical appendix referenced on page 20. When that is submitted, we expect to provide additional comment. To allow for review, we request expedited submission.

Page 21: At bottom of page, “project” should be “re-inventoried” or something that refers to an inventory produced after the fact.

Page 22, paragraph 1, Space heating area sources. Please further explain how the combined survey data best represents 2013 emissions.

Page 23: Add information about how NH_3 was inventoried for this category.

Page 23, 2nd paragraph from bottom. Facilities need to provide direct PM and all precursors, whether directly submitted or calculated from emissions factors.

Page 23, last paragraph.

- Potential typo – we believe that 2018 should be 2013.
- Question – Does scaling emissions cause any point source to exceed its PTE?

Page 25, bullet 3, Laboratory – Measured Emissions Factors for Fairbanks Heating Devices. The statement “first and most comprehensive systematic” would be more credible if simplified.

Page 27: Clarify how data from the 2014 NEI was modified to reflect emissions in 2013. Were they assumed to be the same between the two years? Or adjusted based on population change, or some other information?

Page 33: Please include information on how the Speciate database was used to develop the modeling inventory (and perhaps elsewhere for the planning inventory, if appropriate).

Precursor Demonstration

Throughout the Serious Area SIP we recommend using the terminology, Precursor Demonstration, to be consistent with the $PM_{2.5}$ Implementation Rule.

General: The overview of the nitrate chemistry is complicated. We suggest you combine the two discussions into one and organize it with the following logic:

1. Describe the two chemical environments: (1) daytime and (2) nighttime.
2. Describe the information that supports that daytime chemistry is not relevant here.
3. Describe the information that supports that nighttime chemistry is limited by excess NO.

4. Describe what happens if the entire emission inventory was increasing by a factor of 3.6 to get appropriate concentrations in the North Pole area. How does ammonium nitrate change?
5. Describe how increasing the emission inventory and then reducing all source sectors by 75% results in less of a reduction in $P_{M2.5}$ than reducing all source sectors by 75% in the original emission inventory.
6. NOTE: We are willing to provide a rough draft of this organization, if provided the original word document.

Title page: remove "com"

Page 2: Recommend using Section 188-190 instead of 7513-7513b.

Page 2: Recommend moving the last three sentences of the first paragraph to the end of the second paragraph.

Page 2: Please add "threshold" after 1.3 in the third paragraph.

Page 2: Please explain concentration-based and sensitivity-based before using the terms.

Page 2: Please add a footnote whether the numbers in the Executive Summary are SANDWICHed or not.

Page 3: Please change "has decided" to "decided."

Page 3: Make sure the concentrations listed for ammonia include ammonium sulfate and ammonium nitrate.

Page 5-7: The figure captions say that concentrations are presented but the images themselves have percentages. Please use concentrations for this analysis.

Page 9: The first paragraph says that the point sources are not responsible for the majority of sulfate at the monitors. Please substantiate that claim, or modify it.

Page 13: Please explain the relevance of referring to the VOC emissions of home heating in this summary of VOCs.

Page 14: Recommend adding "… and adjusted to reflect speciated concentrations for a total PM2.5 equal to the five year 2011-2015 design value" to the sentence that starts "The speciated PM2.5 data [were] analyzed.

Page 14: Please include the results of the concentration based analysis, perhaps as a table.

Page 14: Clarify that the concentration used for NH_3 is the ammonium sulfate and ammonium nitrate. See the draft EPA Precursor Demonstration Guidance.

Page 17: Recommend removing "slightly" and removing the sentence referring to rounding to the nearest tenth of a microgram.

Page 17-18: To help understand what is going on with the bounding run versus the normal run, it would be helpful to have the RRFs for the Modeled 75% scenario.

BACM

Page 9 and throughout: For clarity, please refer to the implementation rule as "$PM_{2.5}$" not "PM".

Page 14, Table 3. It would be helpful to include filter speciation data.

Page 16, Table 4: Please identify the RACM measures that were technologically and economically feasible but could not be implemented in the RACM timeline or note there were none.

Page 20 and 25, Table 6 and 7: For the final Table identifying the control measures evaluated, it would be helpful to identify the following: measure, cost/ton, BACM determination, MSM determination, and any additional comments.

Page 24: 12 measures were eliminated because they were determined to offer marginal or unquantifiable benefit. However, a measure may offer marginal benefit but may also cost very little. If there is another explanation for why these measures were not considered that follows the BACM steps, please include that in the Serious Area Plan.

Page 28: Stage 1 alerts are referred to multiple times including in Measure 2 on page 28 and Measure 33, pg 47 and pg 48. Please clarify in these analyses whether the measure applies during all stages of alerts and the associated level of control with each stage.

Page 33: Measure 13 identified that no SIPs existed or EPA guidance/requirements for the measure and incorrectly used that rationale as the conclusion for not considering the measure.

Page 34: The discussion of Measure 15 does not clearly state how Alaska and the Borough ensure that devices are taken out at the point of sale. It also does not clearly state the process for ensuring a NOASH application doesn't involve a stove that should have been taken out at the point of sale. It also states that stoves between 2.5 g/hr and 7.5 g/hr can get a NOASH, whereas page 37 implies that a stove must be <2.5 g/hr to be eligible for a NOASH.

Page 47: Measure 33 in Klamath County and Feather River is more stringent than what exists in Fairbanks now. Fairbanks allows open burning without a permit when there is no stage restriction. Alaska DEC prohibits open burning between November 1 and March 31, but the air quality plan makes it clear that the state relies on the Borough to carry out the air quality program in Fairbanks. The fact that the local borough does not require a permit for open burning outside of curtailments makes this measure less stringent in Fairbanks than in other locations. In addition, Fairbanks does not curtail warming fires during a Stage 1.

Page 48: Measure 34 is less stringent in Fairbanks than in Klamath County. Uncertainty in weather forecasting means that Stage 1 alerts are not called correctly all the time, and not

everyone is aware of when an alert is in effect. It is much simpler and less prone to error to prohibit burn barrels and outdoor burning devices entirely.

Page 57: Measure 46 review curtailment exemptions. The current Fairbanks curtailment exemption "These restrictions shall not apply during a power failure." should be reviewed to clarified that it only applies to homes reliant on electricity for heating. As currently written, it appears overly broad.

Page 68: Measure R7, Ban Use of Hydronic Heaters, incorrectly identifies that no other SIPs implemented the measure as rational for not evaluating.

Page 72: Measure R15 is technologically feasible.

Page 78: It may help to make a section break or Section 2 label for "Analysis of Marginal / Unquantifiable Benefit BACM Measures

Page 81-83: The discussion of Measure 6 may need additional documentation. Anecdotal evidence is that damping is common in Fairbanks and is potentially a bigger source of pollution than not having a damper at very cold conditions. If installation by a certified technician addresses this issue, that should be documented.

Page 84: The quote, "did not know if the rule had worked well" needs a reference. It is also not clear of how relevant that is. It could be implemented well in Fairbanks and the fact that it may not have worked well in another location does not make it technologically infeasible for this location.

Page 85-86: While qualitative assessments are helpful to provide context, a quantitative assessment will be necessary to evaluate the measures as BACM and MSM.

Page 88: There are references to Fairbanks in the conclusion for Measure 17, but the analysis refers to AAC code.

Page 89: There appears to be missing text in the Background section related to Method 9.

Page 91: Measure 23 could consider the solution that the decals could be reflective and would be seen by vehicle headlights. Measure 23 could also consider that the decals are used by neighbors to determine who is or is not in compliance. This may be helpful as citizen compliance assistance efforts could supplement the Borough enforcement program.

Page 98-100: Measure 40 needs to include a discussion of all the areas listed on page 22. In addition, if a date certain measure or if Measure 29 were instituted, Measure 40 would essentially be achieved.

Page 114: Measure R5 describes a similar rule in Utah but lists "none" under implementing jurisdictions. Please make consistent.

ULS Heating Oil

Page vii and Page 16: Please check your information on the percentage of households who have a central oil fired furnace. Please consult ADEC's contractor for the emissions inventory and home heating surveys about (1) the percentage of homes that heat only with an oil furnace, and (2) home with a central oil burner and a wood stove. We have seen different numbers than presented here.

Page 13: Please check the labels for Fairbanks HS #2 and Fairbanks HS #1. They may be switched.

Page 14: The statement that there is "a clear explanation" may not be correct, or at minimum is an overstatement. The difference in price between HS#1 and ULSD has varied over time, and the report did not include an explanation for the variations.

Page 14: The third paragraph assumes that the capital costs of shipping ULS would be more than exists today. However, all heating oil is shipped, regardless of sulfur content, and there is no justification for the report for why shipping ULS would be higher than for HS. Additionally, it is possible that the shipping cost per unit could go down marginally if only one product is being supplied to Fairbanks and/or if the quantity supplied increases.

Page 21: The text and Table 7 present inconsistent information. For instance, the text says that the discounted net-present value of scenario 2 is $10,232 while the table says it is $5,768.56.

From:	Ollila, Tera L (DEC)
To:	"richard.l.morris56.civ@mail.mil"
Cc:	Koch, Denise (DEC); Hartig, Lawrence L (DEC); Edwards, Alice L S (DEC); Heil, Cynthia L (DEC); Huff, Deanna M (DEC); Simpson, Aaron J (DEC); Plosay, James R (DEC); "eric.m.dick2.civ@mail.mil"; "hamlin.tim@epa.gov"; "hedgpeth.zach@epa.gov"; Spenillo, Justin; Brown, Dan
Subject:	Request for Additional Information for the BACT Technical Memorandum for Fort Wainwright
Date:	Thursday, September 13, 2018 4:00:33 PM
Attachments:	BACT Comment Letter Fort Wainwright 09.13.18.pdf ADEC Request for Additional Information for Fort Wainwright BACT Analysi....pdf DU Preliminary BACT Comments_Final_5.23.18.pdf EPA Comments on ADEC Preliminary Draft SIP Development Materials for the....pdf Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units) ....pdf Voluntary BACT Analysis for Fort Wainwright (Privatized Emission Units) ....pdf Serious SIP BACT due date email.pdf Request for Additional Information for Fort Wainwright BACT Analysis.pdf

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All recipients:

Please review or copy as required.

Thank you.

Tera L. Ollila
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U.S. Army Garrison Alaska (USAG Alaska)
Environmental Protection Agency (EPA)
Alaska Department of Environmental Conservation (ADEC)
Senior Leaders Meeting Agenda
21-22 March 2019

DATE/TIME: Thursday, 21 March 2019 0900-1100 PDT
LOCATION: EPA Region 10, Seattle, WA

DESIRED OUTCOMES:

1. Develop a shared understanding of the collaborative partnership between the two federal agencies, the EPA and the USAG Alaska, and how we can work together in the best interest of the government.
2. Develop a schedule of partnership meetings outside of the multiagency Statement of Cooperation meeting to discuss the USAG Alaska Environmental Program initiatives, the EPA regulatory focus, and strategies for sustaining compliance.
3. Gain the EPA's concurrence that the USAG Alaska's recent and ongoing Pollution Prevention projects and implementation of management controls are appropriate in addressing their concerns.
4. Gain the EPA's understanding of the USAG Alaska commitment to leadership engagement at all levels, the installation's prioritization of compliance sustainability with adequate resourcing, the need for a culture shift to integrate compliance into how the Army executes its mission, and the continuity of operations regarding environmental compliance to ensure an enduring focus after changes of command.

Topic	Action	Lead	Time
Attendees: USAG Alaska (Colonel (COL) Sean Fisher, Mr. Rich Morris, Lieutenant Colonel (LTC) Poirier, Ms. Tracy Carter); Installation Management Command (IMCOM)-Pacific Region (Mr. Mike Harada); EPA Region 10 (Mr. Chris Hladick, Mr. Tim Hamlin, Mr. Ed Kowalski)			
Day One Introduction			
Introductions and Opening Remarks with Garrison Commander's Intent	• COL Fisher introduces the USAG Alaska team and discusses commitment to sustainable compliance.	COL Fisher	0900-0915

U.S. Army Garrison Alaska (USAG Alaska)
Environmental Protection Agency (EPA)
Alaska Department of Environmental Conservation (ADEC)
Senior Leaders Meeting Agenda
21-22 March 2019

Topic	Action	Lead	Time
EPA Senior Leaders' Welcome	• Welcoming remarks by the EPA senior leaders	Mr. Hladick, Mr. Hamlin, Mr. Kowalski	0915-0930
Garrison Commander and Region 10 Administrator Breakout Session	• Senior Leader discussion	COL Fisher and Mr. Hladick	0930-1000
Attorney Breakout Session	• Attorneys discuss legal framework for Clean Air Act compliance and the Heat and Electricity Generation and Distribution Upgrades Environmental Impact Statement	LTC Poirier, Ms. Carter, EPA attorneys, Mr. Hamlin	0930-1030
Technical Subject Matter Expert Breakout Session	• USAG Alaska Environmental Division Chief, IMCOM-Pacific Region Division Chief, and EPA Compliance and Enforcement discussion regarding ongoing actions and initiative to achieve and sustain compliance	Mr. Morris, Mr. Harada, Mr. Kowalski, EPA staff	0930-1030
Closeout Session	• USAG Alaska and EPA Directors reconvene to discuss takeaways, way ahead, and whether desired outcomes were achieved	COL Fisher, Mr. Hamlin, Mr. Kowalski, Mr. Morris, LTC Poirier, Ms. Carter	1030-1100
ADJOURN MEETING			1100

U.S. Army Garrison Alaska (USAG Alaska)
Environmental Protection Agency (EPA)
Alaska Department of Environmental Conservation (ADEC)
Senior Leaders Meeting Agenda
21-22 March 2019

DATE/TIME: Friday, 22 March 2019 0900-1100 PDT
LOCATION: Alaska Department of Environmental Conservation, Juneau, AK

DESIRED OUTCOMES:

1. Develop a shared understanding of the collaborative partnership between the two agencies, ADEC and USAG Alaska, and how we can work together in the best interest of the State of Alaska and the Army.
2. Gain a clear picture of the status of the State Implementation Plan associated with the FNSB Serious NAA and how the HEGDU EIS and preferred alternative may affect or mitigate impacts to the Army mission.
3. Gain consensus on the Spill Prevention and Response program support for off-post spills from military vehicles, and the framework for reimbursement of services provided by ADEC.

Topic	Action	Lead	Time
Attendees: U.S. Army Garrison Alaska (COL Sean Fisher, Rich Morris, LTC Poirier, Tracy Carter); IMCOM-Pacific Directorate (Mike Harada); Alaska Department of Environmental Conservation (ADEC) (Mr. Jason Brune, Ms. Lynn Kent, Ms. Alice Edwards, Ms. Denise Koch, Ms. Emma Pokon, Ms. Cindy Heil)			
Introductions and Opening Remarks with Commander's Intent	• COL Fisher introduces USAG Alaska team and discusses his commitment to sustainable compliance.	COL Fisher	0900-0915
ADEC Senior Leaders' Welcome	• Welcoming remarks by ADEC senior leaders.	Mr. Brune, Ms. Kent, Ms. Edwards, Ms. Koch, Ms. Pokon, Ms. Heil	0915-0930

U.S. Army Garrison Alaska (USAG Alaska)
Environmental Protection Agency (EPA)
Alaska Department of Environmental Conservation (ADEC)
Senior Leaders Meeting Agenda
21-22 March 2019

Topic	Action	Lead	Time
Serious NAA Discussion on SIP and HEGDU EIS	• ADEC Air Program update on the status of the SIP in terms of schedule, proposed BACT, MSM, and how Army proactive actions impact the SIP. • USAG Alaska communicates potential impacts to Army mission.	ADEC Air Program Director, USAG Alaska	0930-1030
SPAR Program	• USAG Alaska presents Army actions that have taken place since 2017-2018 spills to mitigate future spills, handle spills that occur off post, and follow-on actions proposed by ADEC. • ADEC SPAR Director provides clarification on support for off-post spills, decision-making process for requiring follow-on actions by the Army, and the framework for requesting reimbursement for support.	ADEC SPAR Program Director, USAG Alaska	0930-1030
Closeout	• USAG Alaska and ADEC Directors discuss takeaways, way ahead, and whether desired outcomes were achieved	COL Fisher, Mr. Brune, Ms. Kent, Ms. Edwards, Ms. Koch, Ms. Pokon, Ms. Heil, Rich Morris, LTC Poirier, Tracy Carter	1030-1100
ADJOURN MEETING			1100

U.S. Army Garrison Alaska Meetings with EPA Region 10

March 21-22, 2019

Installation Management Command integrates and delivers base support to enable readiness for a globally responsive Army

We are the Army's Home

Serving the Rugged Professional

Garrison Commander's Opening Remarks

The U.S. Army Garrison Alaska (USAG Alaska) is focused on and committed to sustainable compliance with environmental laws and regulations.

- Reprioritization of resources on compliance since May 2017
- Environmental support contract kicked off October 15, 2018 with 6 contractors performing daily compliance inspections and corrective actions
- New Garrison Environmental Policy on March 8, 2019 to enforce accountability through management controls
  - Installation Environmental Performance Standard (IEPS)
  - Environmental Officer minimum rank and leadership engagement
  - Environmental Operating Permits for Battalion Executive Officers (XO) at motor pools
  - Environmental Officer (EO) Training
  - EO's are required to report non-compliance through chain of command to the Garrison Commander
  - EPA fines passed to tenant activities responsible for violations
- Implemented Pollution Prevention (P2) initiatives to reduce compliance burden and carbon footprint, i.e. aerosol can depressurizers and antifreeze recycling
- Investing in P2 initiatives in fiscal year 2019 such as bulk used oil collection for energy recovery and bulk hazardous material fluid distribution systems

Compliance, Sustainability and Mission Support

At the USAG Alaska, our focus is the sustainability of resources and compliance with federal laws while supporting training mission capabilities down range.









Army Sustainability

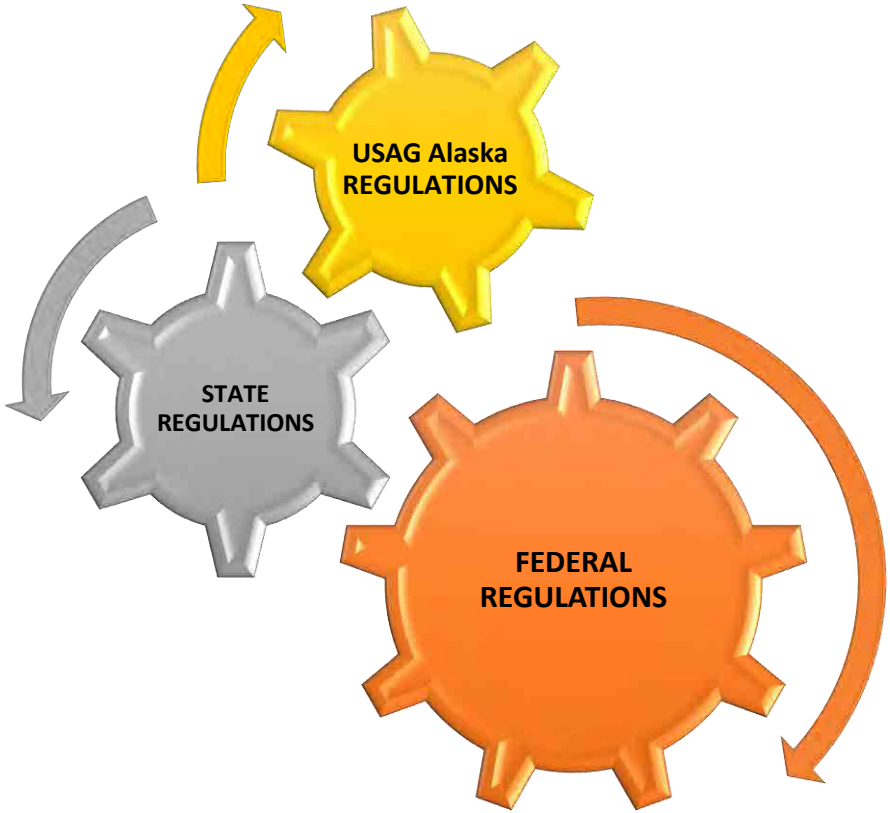


Army Sustainability objectives are to meet current and future mission requirements worldwide, safeguard human health, improve quality of life, and enhance the natural environment.

2011 Army Posture Statement

Regulatory Partnerships

Regulatory Agencies that assist the Army in the protection of the environment in Alaska



USAG Alaska Environmental Policy

USAG Alaska Garrison Policy #37

The USAG Alaska commitment to environmental stewardship in all actions by:

- Fostering an ethic that takes us beyond compliance to sustainability
- Strengthens Army operational capacity by reducing our environmental footprint
- Meeting current and future training and mission requirements minimizing impacts and costs
- Enhancing the well-being of our Soldiers, Civilians, Families, and communities
- Using innovative technologies in anticipation of future challenges

Installation Environmental Performance Standard

- Supports the installation's effort to remain one of Department of Defense's premier training areas
- Integrates environmental requirements into planning considerations
- Maximizes environmental compliance ~ minimize potential for environmental violations/penalties
- Supports the installation's Sustainability Program

Environmental Operating Permit (EOP)

Provides a unit/activity-specific packet of:

- Essential information, such as process/activity maps
- Environmental requirements concerning use of hazardous materials, generation of hazardous/ solid waste and air/water pollutants
- Best management practices

Identifies unit/activity specific requirements

- Must-dos by law/regulation
- Training, records and reports

Provides compliance assistance

- Compliance checklists
- Compliance procedures provided or referenced
- Environmental Operating Permit Advisor (Directorate of Public Works, Environmental Division is tasked as point of contact for environmental questions/assistance)

Environmental Support Contract

On 15 OCT 18, USAG Alaska kicked off a 4-year Environmental Quality Support Services (EQSS) contract ($3.7M annually) to provide the following compliance support:

- Hazardous Waste (HW) Subject Matter Expert (SME)
- Air Quality SME
- Spill Response/Tanks SME
- Water Quality SME
- National Environmental Policy Act SME
- Geographic Information System SME
- Contract Program Manager/Environmental Engineer
- Internal/self inspections – all media
- HW Management/P2 assessments
- Sampling and Analysis – Waste Characterization/Water
- Environmental Officer and SME Training courses
- Compliance schedule and web-based tracking/app

• EQSS provides the necessary manpower (10 FTEs) and other support to ensure and sustain compliance for all media

• Compliance schedule, GIS Compliance Data Layers, Internal Inspection Plan, EO Training, and P2 Opportunity Assessment to mitigate HW generation and compliance burden are deliverables due 31 MAR 19

USAG Alaska Sustainability Goals



VISION:

- Holistic approach to energy, water, and waste
- Enables the Army to appropriately steward available resources, manage costs and provide Soldiers, Families and Civilians with a sustainable future
- With a mission of sustaining future training capabilities, a true stabilizing factor is that of appropriate resource management

USAG Alaska Sustainability Goals



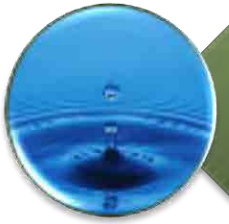
Reduce installation stationary source air emissions by 70% for all criteria air pollutants by 2026



Achieve a net zero waste installation by 2025



Maintain the ability of the USAG Alaska to meet its current and future military missions without compromising environmental compliance or the integrity of resources on the installation



Achieve a net zero water installation by 2025. Exceed water quality requirements to protect human health by 2020

Pollution Prevention

Pollution Prevention (P2) Projects:
Model Motor Pool Waste Evacuation Systems



Used oil/antifreeze caddies used to collect antifreeze and oil underneath vehicles that are being serviced in bay



Used oil bulk tanks located just outside of motor pool connected by piping to transfer waste from caddies

Pollution Prevention

P2 Projects: Model Motor Pool Waste Reduction/Recycling



Antifreeze recycling using Army-approved KFM Antifreeze Recycler to reduce waste volumes, handling, potential spills, and compliance requirements for soldiers. Antifreeze is recycled in the same motor pool that it is generated



Puncture and draining of aerosol cans with paint and flammable liquids to reduce exposure, management, waste volumes, and compliance requirements for soldiers, and facilitate metal recycling

Energy Resiliency



- The Fort Wainwright Power Plant represents a single point failure for the Army mission and has exceeded it's design life
- Complete Heat and Electricity Generation and Distribution Upgrades Environmental Impact Statement by December 2021 and sign Record of Decision by March 2022; $1.3M investment in September 2018
- Implementation of the preferred alternative by 2024
- Evaluate most promising renewable energy sources

End of Brief

USAG Alaska – The Home of America's Arctic Warriors



Questions / Comments / Closing Remarks

University of Alaska Fairbanks (UAF) BACT Determination Documents

- DEC Best Available Control Technology for UAF Fairbanks Campus Power Plant
- DEC letter to Ms. Isgrigg (UAF) for the Request for Additional Information of the BACT Technical Memorandum for UAF by December 22, 2017 (dated October, 2017)
- DEC Request for Additional Information University of Alaska Fairbanks – BACT Technical Memorandum Review, SLR Report July 2016 (dated October 20, 2017)
- DEC letter to Ms. Isgrigg (UAF) on Voluntary BACT analysis for UAF (dated April 24, 2015)
- UAF BACT Analysis Review Comments Reports to EPA January 2017 (dated November 2, 2017)
- DEC Request for Additional Information for University of Alaska Fairbanks (dated December 21, 2017)
- UAF Response to EPA Region 10 and ADEC Comments on BACT Analysis (dated December 21, 2017)
- DEC letter to Ms. Isgrigg (UAF) for additional information for the BACT Analysis Review Technical Memorandum for UAF by November 1, 2018 (on September 13, 2018)
- DEC Request for additional information for BACT Analysis Review SLR Report January 2017 (September 10, 2018)
- UAF response to DEC on the September 13, 2018, request for additional information for BACT memorandum (on November 1, 2018)
- DEC letter to Ms. Isgrigg (UAF) for additional information for the BACT Analysis Review Technical Memorandum for UAF by November 1, 2018 (on September 13, 2018)
- DEC Request for additional information for BACT Analysis Review SLR Report January 2017 (September 10, 2018)
- Attachment 1
- Attachment 2
- Attachment 3
- Attachment 4
- UAF Fairbanks Serious $PM_{2.5}$ Nonattainment Area BACT Determination – Economic Infeasibility OF Sulfur Dioxide (SO_2) Emission Controls

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
Air Permits Program

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION
for
University of Alaska Fairbanks
Fairbanks Campus Power Plant

Prepared by: Brittany Crutchfield
Supervisor: Patrick Dunn
Preliminary Date: May 10, 2019

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Abbreviations/Acronyms

AAC .....Alaska Administrative Code
AAAQS .....Alaska Ambient Air Quality Standards
Department .....Alaska Department of Environmental Conservation
BACT .....Best Available Control Technology
CFB……Circulating Fluidized Bed
CFR. .....Code of Federal Regulations
Cyclones…….Mechanical Separators
DFP……Diesel Particulate Filter
DLN.....Dry Low NOx
DOC……..Diesel Oxidation Catalyst
EPA .....Environmental Protection Agency
ESP…….Electrostatic Precipitator
EU.....Emission Unit
FITR……..Fuel Injection Timing Retard
GCPs……..Good Combustion Practices
HAP.....Hazardous Air Pollutant
ITR…….Ignition Timing Retard
LEA……Low Excess Air
LNB……Low NOx Burners
MR&Rs .....Monitoring, Recording, and Reporting
NESHAPS .....National Emission Standards for Hazardous Air Pollutants
NSCR…….Non-Selective Catalytic Reduction
NSPS .....New Source Performance Standards
ORL.....Owner Requested Limit
PSD.....Prevention of Significant Deterioration
PTE.....Potential to Emit
RICE, ICE .....Reciprocating Internal Combustion Engine, Internal Combustion Engine
SCR .....Selective Catalytic Reduction
SIP .....Alaska State Implementation Plan
SNCR…….Selective Non-Catalytic Reduction
ULSD .....Ultra Low Sulfur Diesel

Units and Measures

gal/hr.....gallons per hour
g/kWh .....grams per kilowatt hour
g/hp-hr .....grams per horsepower hour
hr/day.....hours per day
hr/yr .....hours per year
hp.....horsepower
lb/hr .....pounds per hour
lb/MMBtu.....pounds per million British thermal units
lb/1000 gal.....pounds per 1,000 gallons
kW .....kilowatts
MMBtu/hr.....million British thermal units per hour
MMscf/hr.....million standard cubic feet per hour
ppmv.....parts per million by volume
tpy.....tons per year

Pollutants

CO .....Carbon Monoxide
HAP.....Hazardous Air Pollutant
NOx .....Oxides of Nitrogen
SO_2 .....Sulfur Dioxide
PM-2.5.....Particulate Matter with an aerodynamic diameter not exceeding 2.5 microns
PM-10.....Particulate Matter with an aerodynamic diameter not exceeding 10 microns

1. INTRODUCTION

The University of Alaska Fairbanks (UAF) Campus facility has two coal-fired boilers, installed in 1962, and two oil-fired boilers (converted to dual fuel-fired by Minor Permit No. AQ0316MSS02), installed in 1970 and 1987. The power plant also has a 13,266 hp backup diesel generator installed in 1998. The UAF Campus also includes 13 diesel-fired boilers installed between 1985 and 2005, three emergency diesel engines installed between 1998 and 2013, one classroom engine installed in 1987, and one permitted diesel engine not yet installed. Additional permitted EUs not yet installed at the UAF Campus include limestone, sand, and ash handling systems, a circulating fluidized bed dual fuel-fired boiler, and a coal handling system.

In a letter dated April 24, 2015, the Alaska Department of Environmental Conservation (Department) requested the stationary sources expected to be major stationary sources in the particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers (PM-2.5) serious nonattainment area perform a voluntary Best Available Control Technology (BACT) review in support of the state agency's required SIP submittal once the nonattainment area is re-classified as a Serious PM-2.5 nonattainment area. The designation of the area as "Serious" with regard to nonattainment of the 2006 24-hour PM-2.5 ambient air quality standards was published in Federal Register Vol. 82, No. 89, May 10, 2017, pages 21703-21706, with an effective date of June 9, 2017.[1]

This report addresses the significant EUs listed in permit AQ0316TVP02, Revision 1 and permit AQ0316MSS06, Revision 1. This report provides the Department's review of the BACT analysis for PM-2.5 and BACT analyses provided for oxides of nitrogen (NOx) and sulfur dioxide (SO_2) emissions, which are precursor pollutants that can form PM-2.5 in the atmosphere post combustion.

The sections review UAF's BACT analysis for technical accuracy and adherence to accepted engineering cost estimation practices.

2. BACT EVALUATION

A BACT analysis is an evaluation of all available control options for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts. 40 CFR 52.21(b)(12) defines BACT as a site-specific determination on a case-by-case basis. The Department's goal is to identify BACT for the permanent emission units (EUs) at the UAF Campus Facility that emit NOx, PM-2.5, and SO_2, establish emission limits which represent BACT, and assess the level of monitoring, recordkeeping, and reporting (MR&Rs) necessary to ensure UAF applies BACT for the EUs. The Department based the BACT review on the five-step top-down approach set forth in Federal Register Volume 61, Number 142, July 23, 1996 (Environmental Protection Agency). Table A presents the EUs subject to BACT review.

[1] [1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)

Table A: Emission Units Subject to BACT Review

EU ID[1]	Description of EU	Rating / Size	Fuel Type	Installation or Construction Date
3	Dual-Fired Boiler	180.9 MMBtu/hr	Dual Fuel	1970
4	Dual-Fired Boiler	180.9 MMBtu/hr	Dual Fuel	1987
8	Peaking/Backup Diesel Generator	13,266 hp	Diesel	1999
9A	Medical/Pathological Waste Incinerator	533 lb/hr	Medical / Infectious Waste	2006
19	Diesel Boiler	6.13 MMBtu/hr	Diesel	2004
20	Diesel Boiler	6.13 MMBtu/hr	Diesel	2004
21	Diesel Boiler	6.13 MMBtu/hr	Diesel	2004
23	Diesel Generator Engine	235 kW	Diesel	2003
24	Diesel Generator Engine	51 kW	Diesel	2001
26	Diesel Generator Engine	45 kW	Diesel	1987
27	Diesel Generator Engine	500 hp	Diesel	TBD
28	Diesel Generator Engine	120 hp	Diesel	1998
29	Diesel Generator Engine	314 hp	Diesel	2013
105	Limestone Handling System	1,200 acfm	N/A	TBD
107	Sand Handling System	1,600 acfm	N/A	TBD
109	Ash Handling System	1,000 acfm	N/A	TBD
110	Ash Handling System Vacuum	2,000 acfm	N/A	TBD
111	Ash Loadout to Truck	N/A	N/A	TBD
113	Dual Fuel-Fired Circulating Fluidized Bed (CFB) Boiler	295.6 MMBtu/hr	Coal/Woody Biomass	TBD
114	Dry Sorbent Handling Vent Filter Exhaust	5 acfm	N/A	TBD
128	Coal Silo No. 1 with Bin Vent	1,650 acfm	N/A	TBD
129	Coal Silo No. 2 with Bin Vent	1,650 acfm	N/A	TBD
130	Coal Silo No. 3 with Bin Vent	1,650 acfm	N/A	TBD

Table Notes:
[1]EUs 105, 107, 109-111, 113, 114, and 128-130 were authorized for construction with the issuance of Minor Permit AQ0316MSS06, Revision 2, but have not yet been installed.

UAF did not include BACT analyses for EUs 1 and 2 as it is required that these EUs be decommissioned with the startup of EU 113 under Minor Permit AQ0316MSS06, Revision 2. UAF did not include BACT analyses for EUs 10-16, 24-26, 28, and 29 because the emissions controls for these units are economically infeasible for the small potential emissions that could be controlled. Small diesel-fired boilers 17, 18, and 23, and small diesel-fired engine were also not included in the BACT analysis as these are units similar to those included in the BACT analysis. The Department did not require every EU to be included in the BACT analysis as long as a similar unit was included.

Five-Step BACT Determinations
The following sections explain the steps used to determine BACT for NOx, PM-2.5, and SO_2 for the applicable equipment.

Step 1 Identify All Potentially Available Control Technologies
The Department identifies all available control technologies for the EUs and the pollutant under consideration. This includes technologies used throughout the world or emission reductions through the application of available control techniques, changes in process design, and/or

operational limitations. To assist in identifying available controls, the Department reviews available technologies listed on the Reasonably Available Control Technology (RACT), BACT, and Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC). The RBLC is an EPA database where permitting agencies nationwide post imposed BACT for PSD sources. In addition to the RBLC search, the Department used several search engines to look for emerging and tried technologies used to control NOx, PM-2.5, and SO_2 emissions from equipment similar to those listed in Table A.

Step 2 Eliminate Technically Infeasible Control Technologies:
The Department evaluates the technical feasibility of each control technology based on source specific factors in relation to each EU subject to BACT. Based on sound documentation and demonstration, the Department eliminates control technologies deemed technically infeasible due to physical, chemical, and engineering difficulties.

Step 3 Rank the Remaining Control Technologies by Control Effectiveness
The Department ranks the remaining control technologies in order of control effectiveness with the most effective at the top.

Step 4 Evaluate the Most Effective Controls and Document the Results as Necessary
The Department reviews the detailed information in the BACT analysis about the control efficiency, emission rate, emission reduction, cost, environmental, and energy impacts for each option to decide the final level of control. The analysis must present an objective evaluation of both the beneficial and adverse energy, environmental, and economic impacts. A proposal to use the most effective option does not need to provide the detailed information for the less effective options. If cost is not an issue, a cost analysis is not required. Cost effectiveness for a control option is defined as the total net annualized cost of control divided by the tons of pollutant removed per year. Annualized cost includes annualized equipment purchase, erection, electrical, piping, insulation, painting, site preparation, buildings, supervision, transportation, operation, maintenance, replacement parts, overhead, raw materials, utilities, engineering, start-up costs, financing costs, and other contingencies related to the control option. Sections 3, 4, and 5 present the Department's BACT Determinations for NOx, PM-2.5, and SO_2.

Step 5 Select BACT
The Department selects the most effective control option not eliminated in Step 4 as BACT for the pollutant and EU under review and lists the final BACT requirements determined for each EU in this step. A project may achieve emission reductions through the application of available technologies, changes in process design, and/or operational limitations. The Department reviewed UAF's BACT analysis and made BACT determinations for NOx, PM-2.5, and SO_2 for the UAF Campus Power Plant. These BACT determinations are based on the information submitted by UAF in their analysis, information from vendors, suppliers, sub-contractors, RBLC, and an exhaustive internet search.

3. BACT DETERMINATION FOR NOx

The NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC is planning to submit with the Serious SIP a final precursor demonstration as justification not to require NOx controls. Please see the precursor demonstration for NOx posted at http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip-development. The PM2.5 NAAQS Final SIP Requirements Rule states if the state determines through a precursor demonstration that controls for a precursor gas are not needed for attaining the standard, then the controls identified as BACT/BACM or Most Stringent Measure for the precursor gas are not required to be implemented.[2] Final approval of the precursor demonstration is at the time of the Serious SIP approval.

The Department based its NOx assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by Golden Valley Electric Association (GVEA) for the North Pole Power Plant and Zehnder Facility, Aurora Energy, LLC (Aurora) for the Chena Power Plant, U.S. Army Corps of Engineers (US Army) for Fort Wainwright, and the University of Alaska Fairbanks (UAF) for the Combined Heat and Power Plant.

3.1 NOx BACT for the Large Dual Fuel-Fired Boiler (EU 113)

Possible NOx emission control technologies for the large dual fuel-fired boiler were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.110, Coal Combustion in Industrial Size Boilers and Furnaces. The search results for coal-fired boilers are summarized in Table 3-1.

Table 3-1. RBLC Summary of NOx Control for Industrial Coal-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Selective Catalytic Reduction	9	0.05 – 0.08
Selective Non-Catalytic Reduction	18	0.07 – 0.36
Low NOx Burners	18	0.07 – 0.3
Overfire Air	8	0.07 – 0.3
Good Combustion Practices	2	0.1 – 0.6

RBLC Review

A review of similar units in the RBLC indicates selective catalytic reduction, selective non-catalytic reduction, low NOx burners, and good combustion practices are the principle NOx control technologies installed on large dual fuel-fired boilers. The lowest NOx emission rate in the RBLC is 0.05 lb/MMBtu.

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf

Step 1 - Identification of NOx Control Technology for the Large Dual Fuel-Fired Boiler
From research, the Department identified the following technologies as available for control of NOx emissions from the large dual fuel-fired boiler:

(a) Selective Catalytic Reduction (SCR)[3]
SCR is a post-combustion gas treatment technique for reducing nitric oxide (NO) and nitrogen dioxide (NO_2) in the turbine exhaust stream to molecular nitrogen (N_2), water, and oxygen (O_2). In the SCR process, aqueous or anhydrous ammonia (NH_3) is injected into the flue gas upstream of a catalyst bed. The catalyst lowers the activation energy of the NOx decomposition reaction. NOx and NH_3 combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental N_2 and water. Depending on the overall NH_3-to-NOx ratio, removal efficiencies are generally 70 to 90 percent. Challenges associated with using SCR on coal fired boilers include a narrow window of acceptable inlet and exhaust temperatures (500°F to 800°F), emission of NH_3 into the atmosphere (NH_3 slip) caused by non-stoichiometric reduction reaction, and disposal of depleted catalysts. The Department considers SCR a technically feasible control technology for the large dual fuel-fired boiler.

(b) Selective Non-Catalytic Reduction (SNCR)
SNCR involves the non-catalytic decomposition of NOx in the flue gas to N_2 and water using reducing agents such as urea or NH_3. The process utilizes a gas phase homogeneous reaction between NOx and the reducing agent within a specific temperature window. The reducing agent must be injected into the flue gas at a location in the unit that provides the optimum reaction temperature and residence time. The NH_3 process (trade name-Thermal DeNOx) requires a reaction temperature window of 1,600°F to 2,200°F. In the urea process (trade name–NO_xOUT), the optimum temperature ranges between 1,600°F and 2,100°F. Because the temperature of CFB boiler exhaust gas normally ranges from 1,550°F to 1,650°F, achieving the required reaction temperature is the main difficulty for application of SNCR to coal-fired boilers. Expected NOx removal efficiencies are typically between 40 to 62 percent, according to the RBLC, or between 30 and 50 percent reduction, according to the EPA fact sheet (EPA-452/F-03-031). Additionally, UAF received a statement from the manufacturer Babcock & Wilcox that SNCR would have a NOx removal efficiency of 10 to 20 percent with an ammonia lip of less than 20 ppm. The Department considers SNCR a technically feasible control technology for the large dual fuel-fired boiler.

(c) Non-Selective Catalytic Reduction (NSCR)
NSCR simultaneously reduces NOx and oxidizes CO and hydrocarbons in the exhaust gas to N_2, carbon dioxide (CO_2), and water. The catalyst, usually a noble metal, causes the reducing gases in the exhaust stream (hydrogen, methane, and CO) to reduce both NO and NO_2 to N_2 at a temperature between 800°F and 1,200°F, below the expected temperature of the CFB boiler flue gas. NSCR requires a low excess O_2 concentration in the exhaust gas stream to be effective because the O_2 must be depleted before the reduction chemistry can proceed. NSCR is only effective with rich-burn gas-fired units that operate at all times with an air/fuel ratio controller at or close to stoichiometric conditions. Coal-fired boilers

[3] https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

operate under conditions far more fuel-lean than required to support NSCR. The Department's research did not identify NSCR as a control technology used to control NOx emissions from large coal fired boilers installed at any facility after 2005. The Department does not consider NSCR a technically feasible control technology for the large dual fuel-fired boiler.

(d) Low NOx Burners (LNBs)
Using LNBs can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature. Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 60% but under certain conditions, higher reductions are possible. The Department considers the use of LNBs a technically feasible control technology for the large dual fuel-fired boiler.

(e) Circulating Fluidized Bed (CFB)
In a fluidized bed combustor, fuel is introduced to a bed of either sorbent (limestone) or inert material (usually sand) that is fluidized by an upward flow of air. This upward air flow allows for better mixing of the gas and solids to create a better heat transfer and chemical reactions. Combustion takes place in the bed at a lower temperature than other boiler types which lowers the formation of thermally generated NOx. The Department considers the use of a CFB as a technically feasible control technology for the large dual fuel-fired boiler.

(f) Low Excess Air (LEA)
Boiler operation with low excess air is considered an integral part of good combustion practices because this process can maximize the boiler efficiency while controlling the formation of NOx. Boilers operated with five to seven percent excess air typically have peak NOx formation from both peak combustion temperatures and chemical reactions. At both lower and higher excess air concentrations the formation of NOx is reduced. At higher levels of excess air, an increase in the formation of CO occurs. CO can increase reduced. As a result, the preference is to reduce excess air such that both NOx and CO generation is minimized and the boiler efficiency is optimized. Only one RLBC entry identified low excess air technology as a NOx control alternative for a mass-feed stoker designed boiler. Boilers are regularly designed to operate with low excess air as described in the previous LNB discussion. Low excess air technology can be achieved through LNB with a staged combustion and will therefore not be a technology carried forward.

(g) Good Combustion Practices (GCPs)
GCPs typically include the following elements:

1. Sufficient residence time to complete combustion;
2. Providing and maintaining proper air/fuel ratio;
3. High temperatures and low oxygen levels in the primary combustion zone;

4. High enough overall excess oxygen levels to complete combustion and maximize thermal efficiency.

Combustion efficiency is dependent on the gas residence time, the combustion temperature, and the amount of mixing in the combustion zone. GCPs are accomplished primarily through combustion chamber design as it relates to residence time, combustion temperature, air-to-fuel mixing, and excess oxygen levels. The Department considers GCPs a technically feasible control technology for the dual fuel-fired boiler.

(h) Fuel Switching

This evaluation considers retrofit of existing coal-fired boilers. It is assumed that use of another type of coal would not reduce NOx emissions. Therefore, the Department does not consider the use of an alternate fuel to be a technically feasible control technology for the dual fuel-fired boiler.

(i) Steam / Water Injection

Steam/water injection into the combustion zone reduces the firing temperature in the combustion chamber and has been traditionally associated with reducing NOx emissions from gas combustion turbines but not coal-fired boilers. In addition, steam/water has several disadvantages, including increases in carbon monoxide and un-burned hydrocarbon emissions and increased fuel consumption. Further, the Department found that steam or water injection is not listed in the EPA RBLC for use in any coal-fired boilers and it would be less efficient at controlling NOx emissions than SCR. Therefore, the Department does not consider steam or water injection to be a technically feasible control technology for the existing dual fuel-fired boiler.

(j) Reburn

Reburn is a combustion hardware modification in which the NOx produced in the main combustion zone is reduced in a second combustion zone downstream. This technique involves withholding up to 40 percent (at full load) of the heat input to the main combustion zone and introducing that heat input above the top row of burners to create a reburn zone. Reburn fuel (natural gas, oil, or pulverized coal) is injected with either air or flue gas to create a fuel-rich zone that reduces the NOx created in the main combustion zone to nitrogen and water vapor. The fuel-rich combustion gases from the reburn zone are completely combusted by injecting overfire air above the reburn zone. Reburn may be applicable to many boiler types firing coal as the primary fuel, including tangential, wall-fired, and cyclone boilers. However, the application and effectiveness are site-specific because each boiler is originally designed to achieve specific steam conditions and capacity which may be altered due to reburn. Commercial experience is limited; however, this limited experience does indicate NOx reduction of 50 to 60 percent from uncontrolled levels may be achieved. Reburn combustion control would require significant changes to the design of the existing boilers. Therefore, the Department does not consider reburn to be a technically feasible control technology to retrofit the existing dual fuel-fired boiler.

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Dual Fuel-Fired Boiler
As explained in Step 1 of Section 3.1, the Department does not consider non-selective catalytic reduction, low NOx burners, fuel switching, steam/water injection, or reburn as technically feasible technologies to control NO_x emissions from the dual fuel-fired boiler.

Step 3 - Rank the Remaining NOx Control Technologies for the Large Dual Fuel-Fired Boiler
The following control technologies have been identified and ranked for control of NOx from the large dual fuel-fired boiler:

(a) Selective Catalytic Reduction (70% - 90% Control)
(b) Selective Non-Catalytic Reduction (30%-50% Control)
(g) Good Combustion Practices (Less than 40% Control)
(d) Low NOx Burners/Staged Combustion (0% Control)
(e) Circulating Fluidized Bed (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF provided an economic analysis for the installation of SCR or SNCR in conjunction with CFB and staged combustion. A summary of the analysis is shown below:

Table 3-2. UAF Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	51.8	207.2	$26,740,640	$5,889,642	$22,232
SNCR	207.2	51.8	$2,960,000	$527,764	$10,192
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

UAF contends that the economic analysis indicates the level of NOx reduction does not justify the use of SCR or SNCR for the dual fuel-fired boiler based on the excessive cost per ton of NOx removed per year.

UAF proposed the following as BACT for the large dual fuel-fired boiler:

(a) NOx emissions from the operation of the dual fired boiler will be controlled with the use of CFB and staged combustion; and

(b) NOx emissions from the large dual fuel-fired boiler shall not exceed 0.2 lb/MMBtu.

Department Evaluation of BACT for NOx Emissions from the Dual Fuel-Fired Boiler
The Department revised the cost analysis provided by UAF for the installation of SCR and SNCR using EPA's May 2016 Air Pollution Control Cost Estimation Spreadsheet for Selective Catalytic

Reduction,[4] and Selective Non-Catalytic Reduction,[5] using the unrestricted potential to emit of EU 113, a baseline emission rate of 0.2 lb NOx/MMBtu,[6] a retrofit factor of 1.0 for a retrofit of average difficulty, a NOx removal efficiency of 90% and 50% for SCR and SNCR respectively, an interest rate of 5.5% (current bank prime interest rate), and a 20 year equipment life. A summary of the analysis is shown below:

Table 3-3. Department Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	259	233	$11,676,081	$1,444,246	$6,197
SNCR	259	129	$2,170,943	$291,628	$2,252
Capital Recovery Factor = 0.0837 (5.5% interest rate for a 20 year equipment life)					

The Department's economic analysis indicates the level of NOx reduction justifies the use of SCR or SNCR for the dual fuel-fired boiler located in the Serious PM-2.5 nonattainment area.

Step 5 - Selection of NOx BACT for the Large Dual Fuel-Fired Boiler

The Department's finding is that selective catalytic reduction and selective non-catalytic reduction are both economically and technically feasible control technologies for NOx. Since selective catalytic reduction has a higher control efficiency, it is selected as BACT to control NOx emissions from the dual fuel-fired boiler.

The Department's finding is that BACT for NOx emissions from the dual fuel-fired boiler is as follows:

(a) NOx emissions from EU 113 shall be controlled by operating and maintaining SCR in conjunction with the designed CFB and staged combustion at all times the unit is in operation;

(b) NOx emissions from EU 113 shall not exceed 0.02 lb/MMBtu averaged over a 3-hour period; and

(c) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation.

Table 3-4 lists the proposed BACT determination for this facility along with those for other coal-fired boilers in the Serious PM-2.5 nonattainment area.

[4] https://www3.epa.gov/ttn/ecas/docs/scr_cost_manual_spreadsheet_2016_vf.xlsm
[5] https://www3.epa.gov/ttn/ecas/docs/sncr_cost_manual_spreadsheet_2016_vf.xlsm
[6] Emission rate is NOx limit from 40 C.F.R. 60.44b(l)(1) [NSPS Subpart Db]

Table 3-4. Comparison of NOx BACT for Coal-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.02 lb/MMBtu[7]	Selective Catalytic Reduction
Fort Wainwright	6 Coal-Fired Boilers	1,380 MMBtu/hr	0.06 lb/MMBtu[8]	Selective Catalytic Reduction
Chena	Four Coal-Fired Boilers	497 MMBtu/hr (combined)	0.05 lb/MMBtu[9]	Selective Catalytic Reduction

3.2 NOx BACT for the Mid-Sized Diesel-Fired Boilers (EUs 3 and 4)

Possible NOx emission control technologies for mid-sized diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.220, Industrial Size Distillate Fuel Oil Boilers (>100 MMBtu/hr and ≤ 250 MMBtu/hr). The search results for mid-sized diesel-fired boilers are summarized in Table 3-5.

Table 3-5. RBLC Summary of NOx Control for Mid-Sized Boilers Firing Diesel

Control Technology	Number of Determinations	Emission Limits (lb/1000 gal)
No Control Specified	2	4 – 13

Possible NOx emission control technologies for mid-sized diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.310, Industrial Size Gaseous Fuel Boilers (>100 MMBtu/hr and ≤ 250 MMBtu/hr). The search results for mid-sized diesel-fired boilers are summarized in Table 3-6.

Table 3-6. RBLC Summary of NOx Control for Mid-Sized Boilers Firing Natural Gas

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Selective Catalytic Reduction	7	0.01 – 0.014
Low NOx Burners	26	0.01 – 0.12
Limited Operation	1	0.098
Good Combustion Practices	6	0.0002 – 0.119
No Control Specified	7	0.04 – 0.14

RBLC Review

A review of similar units in the RBLC indicates selective catalytic reduction, low-NOx burners, limited operation, and good combustion practices are the principle NOx control technologies installed on mid-sized boilers. The lowest NOx emission rate listed in the RBLC is 0.0002 lb/MMBtu.

Step 1 - Identification of NOx Control Technology for the Mid-Sized Diesel-Fired Boilers

[7] Calculated using a 90% NOx control efficiency for SCR with uncontrolled emission rate from 40 C.F.R. 60.44b(l)(1) [NSPS Subpart Db].

[8] Calculated using a 90% NOx control efficiency for SCR with uncontrolled emission factor from AP-42 Table 1.1-3 for spreader stoker sub-bituminous coal (8.8 lb NOx/ton) and converted to lb/MMBtu using heat value for Usibelli Coal of 7,560 Btu/lb, http://www.usibelli.com/coal/data-sheet.

[9] Calculated using a 90% NOx control efficiency for SCR with uncontrolled emission rate from most recent NOx source test, which occurred on Oct 27, 2018.

From research, the Department identified the following technologies as available for NOx control of mid-sized diesel-fired boilers:

(a) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT for the dual fuel-fired boiler and will not be repeated here. The Department considers SCR a technically feasible control technology for the mid-sized diesel-fired boilers.

(b) Selective Non-Catalytic Reduction
The theory of SNCR was discussed in detail in the NOx BACT for the CFB dual fuel-fired boiler and will not be repeated here. The expected NOx control efficiency for the SNCR without LNB is 30 to 50 percent, and with LNB is 65 to 75 percent. The Department considers SNCR a technically feasible control technology for the mid-sized diesel-fired boilers.

(c) Low NOx Burners
The theory of LNBs was discussed in detail in the NOx BACT for the CFB dual fuel-fired boiler and will not be repeated here. EUs 3 and 4 currently have LNB controls in the place. If the LNB systems were to be replaced an estimated NOx control efficiency of 35 to 55 percent is expected. The use of LNBs is a technically feasible control technology for the mid-sized diesel-fired boilers.

(d) Natural Gas
Natural gas combustion has a lower NOx emission rate than diesel combustion. For this reason, combustion of natural gas rather than diesel is preferred. EU 4 is equipped to burn natural gas, but due to the lack of guarantee of natural gas always being available to them, UAF has retained the ability due to burn diesel in EU 4. EU 3 is not currently configured to burn natural gas. UAF has had pressure issues with operating EU 4 on natural gas and feels that operating both mid-sized diesel-fired boilers on natural gas would create an issue. The Department agrees that operating on natural gas is not a technically feasible control technology for the mid-sized diesel-fired boilers.

(e) Limited Operation
EU 4 currently has an owner requested limit through the Title I permitting program to limit NOx emissions to no more than 40 tons per 12 month rolling period. With the limit on operation in place the NOx emissions are reduced from EU 4. The Department considers limited operation a technically feasible control technology for the mid-sized diesel-fired boilers.

(f) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the CFB dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of NOx emissions. The Department considers GCPs a technically feasible control technology for the mid-sized diesel-fired boilers.

Step 2 - Eliminate Technically Infeasible NOx Controls for the Mid-Sized Boilers
As explained in Step 1 of Section 3.2, the Department does not consider switching fuel to natural gas as technically feasible technologies to control NOx emissions from the mid-sized diesel-fired boilers.

For EU 4, SCR is not a technically feasible technology due to the lack of space surrounding the EU required for an SCR system.

EU 3 is used as a backup to the existing large boilers if one of them fails, and will be used as the backup to EU 113 if it fails. As the backup EU, it is not technically feasible to use an operational limit to control NOx emissions.

SNCR is not identified in the RBLC as a control technology used for diesel-fired boilers between 100 and 250 MMBtu/hr and is therefore not considered a feasible technology.

Step 3 - Rank the Remaining NOx Control Technologies for the Mid-Sized Diesel-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from EU 3.

(a) Selective Catalytic Reduction (80% - 90% Control)
(c) Low NOx Burners (35% - 55% Control)
(f) Good Combustion Practices (Less than 40% Control)

The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from EU 4.

(c) Low NOx Burners (35% - 55% Control)
(f) Good Combustion Practices (Less than 40% Control)
(e) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF provided an economic analysis for the installation of LNB and SCR. A summary of the analysis is shown below:

Table 3-7. Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR (EU 3)	20.8	118.0	$3,434,525	$992,901	$7,261
LNB (EU 3)	79.2	59.6	$1,255,695	$216,454	$3,634
LNB (EU 4)	12.7	1.2	$1,342,628	$231,439	$189,312
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

UAF contends that the economic analysis indicates the level of NOx reductions does not justify the use of SCR or LNB for the mid-sized diesel fired boilers based on the excessive cost per ton of NOx removed.

UAF proposed the following as BACT for NOx emissions from EU 3:

(a) NOx emissions from the operation of EU 3 shall be controlled by good combustion practices; and

(b) NOx emissions from EU 3 shall not exceed 0.2 lb/MMBtu.

UAF proposes the following as BACT for NOx emissions from EU 4:

(a) NOx emissions from the operation of EU 4 shall be controlled by limited operation;

(b) Combined NOx emissions from EUs 4 and 8 shall not exceed 40 tons per 12 month rolling period;

(c) NOx emissions from the operation of EU 4 shall be controlled by good combustion practices; and

(c) NOx emissions from EU ID 4 shall not exceed 0.2 lb/MMBtu while firing diesel fuel and 140 lb/MMscf while firing natural gas.

Department Evaluation of BACT for NOx Emissions from the Mid-Sized Diesel-Fired Boilers

The Department revised the cost analyses provided by UAF for the installation of SCR and LNB on EU 3 using a NOx control efficiency of 90% and 55% respectively, an interest rate of 5.5% (current bank prime interest rate), and a 20 year equipment life. A summary of the analysis is shown below:

Table 3-8. Department Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	138.8	125	$3,434,525	$792,939	$6,348
LNB	138.8	76	$1,255,695	$142,747	$1,870
Capital Recovery Factor = 0.0837 (5.5% interest rate for a 20 year equipment life)					

The Department's economic analysis indicates the level of NOx reduction justifies the use of SCR or LNB as BACT for EU 3 located in the Serious PM-2.5 nonattainment area.

The Department reviewed UAF's proposal for EU 4 and finds that because the EU is already limited to 40 tpy of NOx emissions combined with EU 8, requiring the installation and operation of any add-on control technology will not further reduce annual NOx emissions.

Step 5 - Selection of NOx BACT for the Mid-Sized Diesel-Fired Boilers

The Department's finding is that selective catalytic reduction and low NOx burners are both economically and technically feasible control technologies for NOx. Since selective catalytic reduction has a higher control efficiency, it is selected as BACT to control NOx emissions from EU 3.

The Department's finding is that BACT for NOx emissions from EU 3 is as follows:

(a) NOx emissions from EU 3 shall be controlled by operating and maintaining selective catalytic reduction at all times the unit is in operation;

(b) NOx emissions from EU 3 shall not exceed 0.02 lb/MMBtu averaged over a 3-hour averaging period; and

(c) Maintain good combustion practices at all times of operation by following the manufacturer's operation and maintenance procedures.

The Department's finding is that BACT for NOx emissions from EU 4 is as follows:

(a) NOx emissions from EU 4 shall be controlled by limiting the combined NOx emissions of EU 4 and 8 to no more than 40 tons per 12 month rolling period;

(b) Maintain good combustion practices at all times of operation by following the manufacturer's operation and maintenance procedures and

(c) NOx emissions from EU 4 shall not exceed 0.2 lb/MMBtu while firing diesel fuel and 140 lb/MMscf while firing natural gas, both over a 3-hour averaging period.

Table 3-9 lists the proposed NOx BACT determination for the facility along with those for other mid-sized diesel-fired boilers in the Serious PM-2.5 nonattainment area.

Table 3-9. Comparison of NOx BACT for the Mid-Sized Diesel-Fired Boilers

Facility	EU ID	Process Description	Capacity	Fuel	Limitation	Control Method
UAF	3	Dual Fuel-Fired Boilers	100 – 250 MMBtu/hr	Diesel	0.02 lb/MMBtu	Selective Catalytic Reduction Good Combustion Practices
	4			Diesel	0.2 lb/MMBtu	Limited Operation
				Natural Gas	140 lb/MMscf	Good Combustion Practices

3.3 NOx BACT for the Small Diesel-Fired Boilers (EUs 19-21)

Possible NOx emission control technologies for small diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.220, Commercial/Institutional Size Boilers (<100 MMBtu/hr). The search results for the small diesel-fired boilers are summarized in Table 3-10.

Table 3-10. RBLC Summary of NOx Control for Small Diesel-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Low NOx Burners	3	0.02 – 0.14
Good Combustion Practices	1	0.01

RBLC Review

A review of similar units in the RBLC low NOx burners, and good combustion practices are the principle NOx control technologies installed on small-diesel fired boilers. The lowest emission rate listed in the RBLC is 0.01 lb/MMBtu.

Step 1 - Identification of NOx Control Technology for the Small Diesel-Fired Boilers

From research, the Department identified the following technologies as available for control of NOx emissions from small diesel-fired boilers:

(a) Low NOx Burners
The theory of LNBs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers LNB a technically feasible control technology for small diesel-fired boilers.

(b) Limited Operation
The three small diesel-fired boilers share an operating limit of 19,650 hours per 12 rolling month period. Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation a technically feasible control technology for the small diesel-fired boilers.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers GCPs a technically feasible control technology for the small diesel-fired boilers.

(d) Flue Gas Recirculation (FGR)
Flue gas recirculation involves extracting a portion of the flue gas from the economizer section or air heater outlet and readmitting it to the furnace through the furnace hopper, the burner windbox, or both. This method reduces the concentration of oxygen in the combustion zone and may reduce NOx by as much as 40 to 50 percent in some boilers. Chapter 1.3-7 from AP-42 indicates that FGR can require extensive modifications to the burner and windbox and can result in possible flame instability at high FGR rates. The Department does not consider FGR a technically feasible control technology for the small diesel-fired boilers.

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Small Diesel-Fired Boilers
As explained in Step 1 of Section 3.2, the Department does not consider flue gas recirculation as technically feasible technology for the small diesel-fired boilers.

Step 3 - Rank the Remaining NOx Control Technologies for the Small Diesel-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from the small diesel-fired boilers:

(a)	Low NOx Burners	(35% - 55% Control)
(c)	Good Combustion Practices	(Less than 40% Control)
(b)	Limited Operation	(0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for NOx emissions from the small diesel-fired boilers:

(a) NOx emissions from the operation of the small diesel-fired boilers shall be controlled with limited operation;

(b) Limit the combined operation of EUs 19-21 to no more than 19,650 hours in any 12 month rolling period; and

(c) NOx emissions from the small diesel-fired boilers shall not exceed 1.24 g/MMBtu.

Department Evaluation of BACT for NOx Emissions from Small Diesel-Fired Boilers

The Department reviewed UAF's proposal and finds that the 3 small diesel-fired boilers have a combined potential to emit (PTE) of 8.8 tons per year (tpy) for NOx based on combined operation of 19,650 hours per year. At 8.8 tpy, the cost effectiveness in terms of dollars per ton for add-on pollution control for these units is economically infeasible. The Department finds that in addition to limiting the operation of the small diesel-fired boilers, good combustion practices is BACT for NOx.

Step 5 - Selection of NOx BACT for the Small Diesel-Fired Boilers

The Department's finding is that BACT for NOx emissions from the diesel-fired boilers is as follows:

(a) NOx emissions from EUs 19-21 shall not exceed 0.15 lb/MMBtu[10];

(b) Combined operating limit of no more than 19,650 hours per 12 month rolling period;

(c) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation; and

(d) Compliance with the hour limit will be monitored with an hour meter.

Table 3-11 lists the proposed BACT determination for this facility along with those for other diesel-fired boilers rated at less than 100 MMBtu/hr in the Serious PM-2.5 nonattainment area.

Table 3-11. Comparison of NOx BACT for the Small Diesel-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	3 Diesel-Fired Boilers	< 100 MMBtu/hr	0.15 lb/MMBtu	Limited Operation Good Combustion Practices
Fort Wainwright	27 Diesel-Fired Boilers	< 100 MMBtu/hr	0.15 lb/MMBtu	Limited Operation Good Combustion Practices
GVEA Zehnder	2 Diesel-Fired Boilers	< 100 MMBtu/hr	0.15 lb/MMBtu	Low NOx Burners

3.4 NOx BACT for the Large Diesel-Fired Engine (EU 8)

Possible NOx emission control technologies for large engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.100 to

[10] Emission rate from AP-42 Table 1.3-1 for boilers smaller than 100 MMBtu/hr (20 lb/1,000 gallons of diesel) and converted to lb/MMBtu assuming 0.137 MMBtu/gal diesel (AP-42).

17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 3-12.

Table 3-12. RBLC Summary for NOx Controls for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Selective Catalytic Reduction	3	0.5 - 0.7
Other Add-On Control	1	1.0
Federal Emission Standards	13	3.0 - 6.9
Good Combustion Practices	31	3.0 - 13.5
No Control Specified	60	2.8 - 14.1

RBLC Review
A review of similar units in the RBLC indicates selective catalytic reduction, good combustion practices, and compliance with the federal emission standards are the principle NOx control technologies installed on large diesel-fired engines. The lowest NOx emission rate listed in the RBLC is 0.5 g/hp-hr.

Step 1 - Identification of NOx Control Technology for the Large Diesel-Fired Engine
From research, the Department identified the following technologies as available for the control of NOx emissions from diesel-fired engines rated at 500 hp or greater:

(a) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT for the dual fuel-fired boiler and will not be repeated here. EU 8 currently has an SCR system installed at this time, therefore, the Department considers SCR a technically feasible control technology for the large diesel-fired engine.

(b) Turbocharger and Aftercooler
Turbocharger technology involves the process of compressing intake air in a turbocharger upstream of the air/fuel injection. This process boosts the power output of the engine. The air compression increases the temperature of the intake air so an aftercooler is used to reduce the intake air temperature. Reducing the intake air temperature helps lower the peak flame temperature which reduces NOx formation in the combustion chamber. EU ID 8 is currently operating with a turbocharger and aftercooler. The Department considers turbocharger and aftercooler a technically feasible control technology for the large diesel-fired engine.

(c) Fuel Injection Timing Retard (FITR)
FITR reduces NOx emissions by the delay of the fuel injection in the engine from the time the compression chamber is at minimum volume to a time the compression chamber is expanding. Timing adjustments are relatively straightforward. The larger volume in the compression chamber produces a lower peak flame temperature. With the use of FITR the engine becomes less fuel efficient, particular matter emissions increase, and there is a limit with respect to the degree the timing may be retarded because an excessive timing delay can cause the engine to misfire. The timing retard is generally limited to no more than three degrees. Diesel engines may also produce more black smoke due to a decrease in exhaust temperature and incomplete combustion. FITR can achieve up to 50 percent NOx

reduction. Due to the increase in particulate matter emissions resulting from FITR, this technology will not be carried forward.

(d) Ignition Timing Retard (ITR)
ITR lowers NOx emissions by moving the ignition event to later in the power stroke, after the piston has begun to move downward. Because the combustion chamber volume is not at a minimum, the peak flame temperature is not as high, which lowers combustion temperature and produces less thermal NOx. Use of ITR can cause an increase in fuel usage, an increase PM emissions, and engine misfiring. ITR can achieve between 20 to 30 percent NOx reduction. Due to the increase in the particulate matter emissions resulting from ITR, this technology will not be carried forward.

(e) Federal Standard
RBLC NOx determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 NSPS Subpart IIII, 40 C.F.R 63 Subpart ZZZZ, non-road engines (NREs), or EPA tier certifications. NSPS Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. EU 8 was manufactured prior to July 11, 2005 and has not been reconstructed since. Therefore, EU 8 is not subject to NSPS Subpart IIII. EU 8 is considered an institutional emergency engine and is therefore exempt from NESHAP Subpart ZZZZ. For these reasons federal emission standards will not be carried forward as a control technology.

(f) Limited Operation
EU 8 currently operates under a combined annual NOx emission limit with EU 4. Limiting the operation of emissions units reduces the potential to emit of those units. The Department considers limited operation a technically feasible control technology for the large diesel-fired engine.

(g) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers GCPs a technically feasible control technology for the large diesel-fired engine.

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Large Engine
As explained in Step 1 of Section 3.4, the Department does not consider fuel injection timing retard, ignition timing retard, and federal emissions standards as technically feasible technologies to control NOx emissions from the large diesel-fired engine.

Step 3 - Rank the Remaining NOx Control Technologies for the Large Diesel-Fired Engine
The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from the large diesel-fired engine.

(g)	Good Combustion Practices	(Less than 40% Control)
(a)	Selective Catalytic Reduction	(0% Control)
(b)	Turbocharger and Aftercooler	(0% Control)

(f) Limited operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for NOx emissions from the large diesel-fired engine:

(a) NOx emissions from the operation of the large diesel-fired engine shall be controlled with limited use of the unit;

(b) NOx emissions from the operation of the large diesel-fired engine shall be controlled by operating a turbocharger and aftercooler;

(c) NOx emissions from the large diesel-fired engine shall not exceed 0.0195 g/hp-hr; and

(d) Combined NOx emissions from EUs 4 and 8 shall not exceed 40 tons per 12 month rolling period; and

(e) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation.

Department Evaluation of BACT for NOx Emissions from the Large Diesel-Fired Engine

The Department reviewed UAF's proposal and found that in addition to a turbocharger and aftercooler, and limited operation (all currently in practice), SCR (currently installed but not operating) and good combustion practices are also BACT for the control of NOx emissions from the large diesel-fired engine.

Step 5 - Selection of NOx BACT for the Large Diesel-Fired Engine

The Department's finding is that the BACT for NOx emissions from the large diesel-fired engine is as follows:

(a) NOx emissions from EU 8 shall be controlled by operating SCR, and a turbocharger and aftercooler at all times of operation;

(b) Limit non-emergency operation of EU 8 to no more than 100 hours per year for maintenance checks and readiness testing;

(c) NOx emissions from the large diesel-fired engine shall not exceed 1.3 g/hp-hr[11] averaged over a 3-hour period;

(d) Combined NOx emissions from EUs 4 and 8 shall not exceed 40 tons per 12 month rolling period; and

(e) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation.

Table 3-13 lists the proposed BACT determination for this facility along with those for other diesel-fired engines rated at more than 500 hp located in the Serious PM-2.5 nonattainment area.

[11] Worst-case NOx emissions rate from February 1, 2002 source test report while EU 8 was operating with SCR.

Table 3-13. Comparison of NOx BACT for Large Diesel-Fired Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	8 Large Diesel-Fired Engines	> 500 hp	3.0 – 10.9 g/hp-hr	Limited Operation Good Combustion Practices Federal Emission Standards
UAF	Large Diesel-Fired Engine	13,266 hp	1.3 g/hp-hr	Selective Catalytic Reduction Turbocharger and Aftercooler Good Combustion Practices Limited Operation
GVEA North Pole	Large Diesel-Fired Engine	600 hp	10.9 g/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp (each)	10.9 g/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation

3.5 NOx BACT for the Small Diesel-Fired Engines (EUs 23, 24, and 26 – 29)

Possible NOx emission control technologies for small engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 17.210, Small Internal Combustion Engines (<500 hp). The search results for small diesel-fired engines are summarized in Table 3-14.

Table 3-14. RBLC Summary for NOx Control for Small Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Federal Emission Standards	5	2.2 – 4.8
Good Combustion Practices	25	2.0 – 9.5
Limited Operation	4	3.0
No Control Specified	25	2.6 – 5.6

RBLC Review
A review of similar units in the RBLC indicates limited operation, good combustion practices, and compliance with the federal emission standards are the principle NOx control technologies for small diesel-fired engines. The lowest NOx emission rate listed in the RBLC is 2.0 g/hp-hr

Step 1 - Identification of NOx Control Technology for the Small Diesel-Fired Engine
From research, the Department identified the following technologies as available for NOx control of the small diesel-fired engines:

(a) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers SCR a technically feasible control technology for the small diesel-fired engines.

(b) Turbocharger and Aftercooler
The theory of a turbocharger and aftercooler was discussed in detail in the NOx BACT for the large diesel-fired engine and will not be repeated here. EU 27 currently operates with a turbocharger and aftercooler. The Department considers a turbocharger and aftercooler a technically feasible control technology for the small diesel-fired engines.

(c) Ignition Timing Retard (ITR)
The theory of ITR was discussed in detail in the NOx BACT for the large diesel-fired engine and will not be repeated here. Due to the increase in particulate matter emissions resulting from ITR, this technology will not be carried forward.

(d) Federal Emission Standards
RBLC NOx determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 Subpart IIII, 40 C.F.R 63 Subpart ZZZZ, non-road engines (NREs), or EPA tier certifications. Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. The Department considers meeting the technology based NSPS of Subpart IIII as a technically feasible control technology for the small diesel-fired engines.

(e) Limited Operation
EU 27 currently operates under an owner requested limit of 4,380 hours of operation per 12 month rolling period, and EUs 24, 28, and 29 are considered emergency engines with 100 hour limits per calendar year for non-emergency operations. Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation as a technically feasible control technology for the small diesel-fired engines.

(f) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fired boiler and will not be repeated here. The Department considers GCPs a technically feasible control technology for the small diesel-fired engines.

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Small Engines
As explained in Step 1 of Section 3.5, the Department does not consider ignition timing retard as a technically feasible technology to control NOx emissions from the small diesel-fired engines.

Step 3 - Rank the Remaining NOx Control Technologies for the Small Diesel-Fired Engines
The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from the small diesel-fired engines.

(a)	Selective Catalytic Reduction	(90% Control)
(f)	Good Combustion Practices	(Less than 40% Control)
(d)	Federal Emission Standards	(Baseline)
(b)	Turbocharger and Aftercooler	(0% Control)
(e)	Limited Operation	(0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF provided an economic analysis of the installation of SCR on EU 27. A summary of the analysis is shown below:

Table 3-15. Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Captured Emissions (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.8	6.9	$151,592	$84,544	$12,200
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

UAF contends that the economic analysis indicates the level of NOx reduction does not justify the use of SCR based on the excessive cost per ton of NOx removed per year.

UAF proposes the following as BACT for NOx emissions from the small diesel-fired engine EU 27:

(a) NOx emissions from the operation of the small diesel-fired engine shall be controlled with limited use of the unit;

(b) NOx emissions from the operation of the small diesel-fired engine shall be controlled by complying with the federal standards under 40 C.F.R. 63 Subpart ZZZZ;

(c) NOx emissions from the operation of the small diesel-fired engine shall be controlled by operating a turbocharger and aftercooler;

(d) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation;

(e) NOx emissions from the small diesel-fired engine shall not exceed 3.20 g/hp-hr; and

(f) Operating hours for the small diesel-fired engine shall not exceed 4,380 hours per year.

Department Evaluation of BACT for NOx Emissions from the Small Diesel-Fired Engine

The Department revised the cost analysis provided by UAF for the installation of SCR on EU 27 to a 20 year equipment life. A summary of the analysis is shown below:

Table 3-16. Department Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Captured Emissions (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.8	6.9	$151,592	$84,544	$11,141

Capital Recovery Factor = 0.094 (7% for a 20 year life cycle)

The Department's economic analysis indicates the level of NOx reduction does not justify installing SCR as BACT for the small diesel-fired engine EU 27 in the Serious PM-2.5 nonattainment area.

Step 5 - Selection of NOx BACT for the Small Diesel-Fired Engines
The Department's finding is that BACT for NOx emissions from the small diesel-fired engines is as follows:

(a) NOx emissions from EU 27 shall be controlled by operating a turbocharger and aftercooler at all times of operation;

(b) Limit the operation of EU 27 to no more than 4,380 hours per year;

(c) Limit non-emergency operation of EUs 24, 28, and 29 to no more than 100 hours per year each for maintenance checks and readiness testing;

(d) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation; and

(e) Comply with the numerical BACT emission limits listed in Table 3-17.

Table 3-17. Proposed NOx BACT Limits for the Small Diesel-Fired Engines

EU	Year	Description	Size	Status	BACT Limit	Proposed BACT
23	2003	Detroit Diesel	235 kW	AP-42 Table 3.3-1	14.1 g/hp-hr	Good Combustion Practices
26	1987	Mitsubishi-Bosh	45 kW	AP-42 Table 3.3-1	14.1 g/hp-hr	
27	TBD	Caterpillar C-15	500 hp	Certified Engine	3.2 g/hp-hr	Limit Operation to 4,380 hours per year, Turbo Charger and Aftercooler, & Good Combustion Practices
24	2001	Cummins	51 kW	AP-42 Table 3.3-1	14.1 g/hp-hr	Limit Operation for non-emergency use (100 hours each per year) and Good Combustion Practices
28	1998	Detroit Diesel	120 hp	AP-42 Table 3.3-1	14.1 g/hp-hr	
29	2013	Cummins	314 hp	Certified Engine	0.3 g/hp-hr	

Table 3-18 lists the proposed BACT determination for this facility along with those for other diesel-fired engines rated at less than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 3-18. Comparison of NOx BACT for the Small Diesel-Fired Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	Six Small Diesel-Fired Engines	< 500 hp	0.3 – 14.1 lb/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation
Fort Wainwright	41 Small Diesel-Fired Engines	< 500 hp	3.0 – 14.1 lb/hp-hr	40 CFR 60 Subpart IIII & Limited Operation

3.6 NOx BACT for the Pathogenic Waste Incinerator (EU 9A)

Possible NOx emission control technologies for pathogenic waste incinerators were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 21.300, Hospital, Medical, and Infectious Waste Incinerator. The search results for the pathogenic waste incinerators are summarized in Table 3-19.

Table 3-19. RBLC Summary of NOx Control for Pathogenic Waste Incinerators

Control Technology	Number of Determinations	Emission Limits (lb/hr)
Multiple Chamber Design	1	0.0900

RBLC Review
The RBLC has one entry for medical waste incinerators. The lowest emission rate listed in the RBLC is 0.0900 lb/hr.

Step 1 - Identification of NOx Control Technology for the Pathogenic Waste Incinerator
From research, the Department identified the following technologies as available for control of NOx emissions from pathogenic waste incinerators:

(a) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers SCR a technically feasible control technology for the pathogenic waste incinerator.

(b) Selective Non-Catalytic Reduction
The theory of SNCR was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers SNCR a technically feasible control technology for the pathogenic waste incinerator.

(c) Limited Operation
EU 9A is currently operating under an owner requested limit to combust no more than 109 tons of waste per 12 month rolling period. With this limit NOx emissions for EU 9A are 0.2 tpy. The Department considers limited operation a technically feasible control technology for the pathogenic waste incinerator.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers GCPs a technically feasible control technology for the pathogenic waste incinerator.

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Pathogenic Waste Incinerator
All control technologies are technically feasible. However, the Department finds that due to the limited NOx emissions from the pathogenic waste incinerator (0.2 tpy); SCR and SNCR will not be effective in reducing NOx emissions.

Step 3 - Rank the Remaining NOx Control Technologies for the Pathogenic Waste Incinerator

The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from the pathogenic waste incinerator:

(d) Good Combustion Practices (Less than 40% Control)
(c) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for NOx emissions from the pathogenic waste incinerator:

(a) Limit the operation of pathogenic waste incinerator to no more than 109 tons of waste per 12 month rolling period;

(b) NOx emissions from the pathogenic waste incinerator shall not exceed 3.56 lb/ton;

(c) Compliance with the proposed operational limit will be demonstrated by recording pounds of waste combusted for the pathogenic waste incinerator; and

(d) Maintain good combustion practices.

Step 5 - Selection of NOx BACT for the Pathogenic Waste Incinerator

The Department's finding is that BACT for NOx emissions from the pathogenic waste incinerator is as follows:

(a) NOx emissions from EU 9A shall not exceed 3.56 lb/ton;

(b) Limit the operation of EU 9A to 109 tons of waste combusted per 12 month rolling period;

(c) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation; and

(d) Compliance with the proposed operational limit will be demonstrated by recording pounds of waste combusted for the pathogenic waste incinerator.

Table 3-20 lists the proposed BACT determination for this facility along with those for other waste incinerators located in the Serious PM-2.5 nonattainment area.

Table 3-20. Comparison of NOx BACT for Pathogenic Waste Incinerators at Nearby Power Plants

Facility	Process Description	Capacity	Limitation		Control Method
UAF	One Pathogenic Waste Incinerator	83 lb/hr	3.56	lb/ton	Limited Operation Good Combustion Practices

4. BACT DETERMINATION FOR PM-2.5

The Department based its PM-2.5 assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by GVEA for the North Pole Power Plant and Zehnder Facility, Aurora for the Chena Power Plant, US Army for Fort Wainwright, and UAF for the Combined Heat and Power Plant.

4.1 PM-2.5 BACT for the Large Dual Fuel-Fired Boiler (EU 113)

Possible PM-2.5 emission control technologies for large dual fuel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.110, Coal Combustion in Industrial Size Boilers and Furnaces. The search results are listed in Table 4-1.

Table 4-1. RBLC Summary of PM-2.5 Control for Industrial Coal-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Pulse Jet Fabric Filters	4	0.012 – 0.024
Electrostatic Precipitators	2	0.02 – 0.03

RBLC Review
A review of similar units in the RBLC indicates that fabric filters and electrostatic precipitators are the principle particulate matter control technologies installed on large dual fuel-fired boilers. The lowest PM-2.5 emission rate listed in RBLC is 0.012 lb/MMBtu.

Step 1 - Identification of PM-2.5 Control Technologies for the Large Dual Fuel-Fired Boiler
From research, the Department identified the following technologies as available for control of PM-2.5 emissions from the large dual fuel-fired boiler:

(a) Fabric Filters
Fabric filters or baghouses are comprised of an array of filter bags contained in housing. Air passes through the filter media from the "dirty" to the "clean" side of the bag. These devices undergo periodic bag cleaning based on the build-up of filtered material on the bag as measured by pressure drop across the device. The cleaning cycle is set to allow operation within a range of design pressure drop. Fabric filters are characterized by the type of cleaning cycle: mechanical-shaker,[12] pulse-jet,[13] and reverse-air.[14] Fabric filter systems have control efficiencies of 95% to 99.9%, and are generally specified to meet a discharge concentration of filterable particulate (e.g., 0.01 grains per dry standard cubic feet). The Department considers fabric filters a technically feasible control technology for the large dual fuel-fired boiler.

(b) Wet and Dry Electrostatic Precipitators (ESP)
ESPs remove particles from a gas stream by electrically charging particles with a discharge electrode in the gas path and then collecting the charged particles on grounded plates. The inlet air is quenched with water on a wet ESP to saturate the gas stream and ensure a wetted surface on the collection plate. This wetted surface along with a period deluge of water is what cleans the collection plate surface. Wet ESPs typically control streams with inlet grain loading values of 0.5 – 5 gr/ft^3 and have control efficiencies between 90% and 99.9%.[15] Wet ESPs have the advantage of controlling some amount of condensable particulate

[12] https://www3.epa.gov/ttn/catc/dir1/ff-shaker.pdf
[13] https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf
[14] https://www3.epa.gov/ttn/catc/dir1/ff-revar.pdf
[15] https://www3.epa.gov/ttn/catc/dir1/fwespwpi.pdf
https://www3.epa.gov/ttn/catc/dir1/fwespwpl.pdf

matter. The collection plates in a dry ESP are periodically cleaned by a rapper or hammer that sends a shock wave that knocks the collected particulate off the plate. Dry ESPs typically control streams with inlet grain loading values of 0.5 – 5 gr/ft^3 and have control efficiencies between 99% and 99.9%.[16] The Department considers ESP a technically feasible control technology for the large dual fuel-fired boiler.

(c) Wet Scrubbers

Wet scrubbers use a scrubbing solution to remove PM/PM_{10}/$PM_{2.5}$ from exhaust gas streams. The mechanism for particulate collection is impaction and interception by water droplets. Wet scrubbers are configured as counter-flow, cross-flow, or concurrent flow, but typically employ counter-flow where the scrubbing fluid is in the opposite direction as the gas flow. Wet scrubbers have control efficiencies of 50% - 99%.[17] One advantage of wet scrubbers is that they can be effective on condensable particulate matter. A disadvantage of wet scrubbers is that they consume water and produce water and sludge. For fine particulate control, a venturi scrubber can be used, but typical loadings for such a scrubber are 0.1-50 grains/scf. The Department considers the use of wet scrubbers to be a technically feasible control technology for the large dual fuel-fired boiler.

(d) Cyclone

Cyclones are used in industrial applications to remove particulate matter form exhaust flows and other industrial stream flows. Dirty air enters a cyclone tangentially and the centrifugal force moves the particulate matter against the cone wall. The air flows in a helical pattern from the top down to the narrow bottom before exiting the cyclone straight up the center and out the top. Large and dense particles in the stream flow are forced by inertia into the walls of the cyclone where the material then falls to the bottom of the cyclone and into a collection unit. Cleaned air then exits the cyclone either for further treatment or release to the atmosphere. The narrowness of the cyclone wall and the speed of the air flow determine the size of particulate matter that is removed from the stream flow. Cyclones are most efficient at removing large particulate matter (PM-10 or greater). Conventional cyclones are expected to achieve 0 to 40 percent PM-2.5 removal. High efficiency single cyclones are expected to achieve 20 to 70 percent PM-2.5 removal. The Department considers cyclones a technically feasible control technology for the large dual fuel-fired boiler.

[16] https://www3.epa.gov/ttn/catc/dir1/fdespwpi.pdf
https://www3.epa.gov/ttn/catc/dir1/fdespwpl.pdf

[17] https://www3.epa.gov/ttn/catc/dir1/fcondnse.pdf
https://www3.epa.gov/ttn/catc/dir1/fiberbed.pdf
https://www3.epa.gov/ttn/catc/dir1/fventuri.pdf

(e) Settling Chamber

Settling chambers appear only in the biomass fired boiler RBLC inventory for particulate control, not in the coal fired boiler RBLC inventory. This type of technology is a part of the group of air pollution control collectively referred to as "pre-cleaners" because the units are often used to reduce the inlet loading of particulate matter to downstream collection devices by removing the larger, abrasive particles. The collection efficiency of settling chambers is typically less than 10 percent for PM-10. The EPA fact sheet does not include a settling chamber collection efficiency for PM-2.5. The Department does not consider settling chambers a technically feasible control technology for the large dual fuel-fired boiler.

(f) Good Combustion Practices

The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of PM-2.5 emissions. The Department considers GCPs a technically feasible control technology for the large dual fuel-fired boiler.

Step 2 - Elimination of Technically Infeasible PM-2.5 Control Technologies for the Large Dual Fuel-Fired Boiler

As explained in Step 1 of Section 4.1, the Department does not consider a settling chamber a technically feasible control technology to control PM-2.5 emissions from the large dual fuel-fired boiler.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Large Dual Fired Boiler

The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 from the dual fuel-fired boiler:

(a)	Fabric Filters	(99.9% Control)
(b)	Electrostatic Precipitator	(99.6% Control)
(c)	Scrubber	(50% - 99% Control)
(d)	Cyclone	(20% - 70%)
(f)	Good Combustion Practices	(Less than 40%)

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for PM-2.5 emissions from the large dual fuel-fired boiler:

(a) PM-2.5 emissions shall be controlled by installing, operating, and maintaining a fabric filter; and

(b) PM-2.5 emissions shall not exceed 0.012 lb/MMBtu.

Step 5 - Selection of PM-2.5 BACT for the Large Dual Fuel-Fired Boiler

The Department's finding is that BACT for PM-2.5 emissions from the large dual fuel-fired boilers is as follows:

(a) PM-2.5 emissions from EU 113 shall be controlled by operating and maintaining fabric filters at all times of operation;

(b) PM-2.5 emissions from EU 113 shall not exceed 0.006 lb/MMBtu[18];

(c) Maintain good combustion practices at all times of operation by following the manufacturer's operating and maintenance procedures; and

(d) Initial compliance with the proposed PM-2.5 emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

Table 4-2 lists the proposed PM-2.5 BACT determination for this facility along with those for other industrial coal-fired boilers in the Serious PM-2.5 nonattainment area.

Table 4-2. Comparison of PM-2.5 BACT for Coal-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	One Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.006 lb/MMBtu[18]	Fabric Filters
Fort Wainwright	Six Coal-Fired Boilers	1,380 MMBtu/hr	0.006 lb/MMBtu[18]	Full Steam Baghouse

4.2 PM-2.5 BACT for the Mid-Sized Diesel-Fired Boilers (EUs 3 and 4)

Possible PM-2.5 emission control technologies for mid-sized diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.220, Industrial Size Distillate Fuel Oil Boilers (>100 MMBtu/hr and ≤ 250 MMBtu/hr). The search results for mid-sized diesel-fired boilers are summarized in 4-3.

Table 4-3. RBLC Summary of PM-2.5 Control for Mid-Sized Boilers Firing Diesel

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
No Control Specified	7	0.0066 – 0.02
Good Combustion Practices	3	0.007 – 0.015

Possible PM-2.5 emission control technologies for mid-sized diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.310, Industrial Size Gaseous Fuel Boilers (>100 MMBtu/hr and ≤ 250 MMBtu/hr). The search results for mid-sized diesel-fired boilers are summarized in Table 4-4.

Table 4-4. RBLC Summary of PM-2.5 Control for Mid-Sized Boilers Firing Natural Gas

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Limited Operation	2	0.0074 - 0.3
Good Combustion Practices	42	0.0019 – 0.008
No Control Specified	19	0.0074 – 0.01

RBLC Review
A review of similar units in the RBLC indicates limited operation and good combustion practices are the principle PM-2.5 control technologies installed on mid-sized boilers. The lowest PM-2.5 emission rate listed in the RBLC is 0.0019 lb/MMBtu.

[18] Average soot blown emission rate (rounded up) from worst coal-fired boiler tested at Fort Wainwright (Boiler No. 3) during most recent source test on April 19-22, 24, and 25, 2017.

Step 1 - Identification of PM-2.5 Control Technology for the Mid-Sized Diesel-Fired Boilers
From research, the Department identified the following technologies as available for PM-2.5 control of mid-sized diesel-fired boilers:

(a) Fabric Filters
The theory behind fabric filters was discussed in detail in the PM-2.5 BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers fabric filters a technically feasible control technology for the mid-sized diesel-fired boilers.

(b) Electrostatic Precipitators
The theory behind ESPs was discussed in detail in the PM-2.5 BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers ESPs a technically feasible control technology for the mid-sized diesel-fired boilers.

(c) Scrubber
The theory behind scrubbers was discussed in detail in the PM-2.5 BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers scrubbers a technically feasible control technology for the mid-sized diesel-fired boilers.

(d) Cyclone
The theory behind cyclones was discussed in detail in the PM-2.5 BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers cyclones a technically feasible control technology for the mid-sized diesel-fired boilers.

(e) Natural Gas
The theory behind the use of natural gas for the mid-sized diesel-fired boilers was discussed in detail in the NOx BACT for the mid-sized diesel-fired boilers. The Department does not consider switching to natural gas a technically feasible control technology for the mid-sized diesel-fired boilers.

(f) Limited Operation
The theory behind limited operation for EUs 3 and 4 was discussed in detail in the NOx BACT for the mid-sized diesel-fired boilers and will not be repeated here. The Department considers limited operation a technically feasible control technology for the mid-sized diesel-fired boilers.

(g) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of PM-2.5 emissions. The Department considers GCPs a technically feasible control technology for the mid-sized diesel-fired boilers.

Step 2 - Eliminate Technically Infeasible PM-2.5 Control Technologies for the Mid-Sized Diesel-Fired Boilers

As explained in Step 1 of Section 4.2, the Department does not consider natural gas as a technically feasible technology to control particulate matter emissions from the mid-sized diesel-fired boilers.

Additionally, due to the residue from the diesel combustion in the exhaust gas, fabric filters, scrubbers, ESPs, and cyclones are not technically feasible control technologies.

EU 3 is used as a backup to the existing large boilers if one of them fails, and will be used as the backup to EU 113 if it fails. As the backup EU, it is not technically feasible to use an operational limit to control PM-2.5 emissions.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Mid-Sized Diesel-Fired Boilers
UAF has selected the only remaining control technologies, therefore, ranking is not required.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for the mid-sized diesel-fired boilers:

(a) PM-2.5 emissions from EU 3 and 4 shall not exceed 0.016 lb/MMBtu while firing diesel fuel;

(b) PM-2.5 emissions from EU 4 shall not exceed 7.6 lb/MMscf while firing natural gas; and

(c) PM-2.5 emissions from EU 4 will be limited by complying with the combined annual NOx emission limit of 40 tons per 12 month rolling period for EUs 4 and 8.

Step 5 - Selection of PM-2.5 BACT for the Mid-Sized Diesel-Fired Boilers
The Department's finding is that BACT for PM-2.5 emissions from EUs 3 and 4 is as follows:

(a) PM-2.5 emissions from EUs 3 and 4 shall not exceed 0.012 lb/MMBtu[19] averaged over a 3-hour period while firing diesel fuel;

(b) PM-2.5 emissions from EU 4 shall not exceed 0.0075 lb/MMBtu[20] averaged over a 3-hour period while firing natural gas;

(c) PM-2.5 emissions from EU 4 shall be controlled by limiting combined NOx emissions of EU 4 and 8 to no more than 40 tons per 12 month rolling period;

(d) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation.

Table 4-5 lists the proposed BACT determination for the facility.

Table 4-5. PM-2.5 BACT Limits for the Mid-Sized Diesel-Fired Boilers

Facility	EU ID	Process Description	Capacity	Fuel	Limitation	Control Method
UAF	3	Dual Fuel-Fired Boilers	100 – 250 MMBtu/hr	Diesel	0.012 lb/MMBtu[19]	Good Combustion Practices
	4			Diesel	0.012 lb/MMBtu[19]	Limited Operation

[19] Emission factor from AP-42 Table's 1.3-2 (total condensable particulate matter from No. 2 oil, 1.3 lb/1,000 gal) and 1.3-6 (PM-2.5 size-specific factor from distillate oil, 0.25 lb/1,000 gal) converted to lb/MMBtu.
[20] Emission factor from AP-42 Table 1.4-2 for total particulate matter and converted to lb/MMBtu.

				Natural Gas	0.0075 lb/MMBtu[20]	Good Combustion Practices

4.3 PM-2.5 BACT for the Small Diesel-Fired Boilers (EUs 19 through 21)

Possible PM-2.5 emission control technologies for small diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.220, Commercial/Institutional Size Boilers (<100 MMBtu/hr). The search results for diesel-fired engines are summarized in Table 4-6.

Table 4-6. RBLC Summary of PM-2.5 Control for Small Diesel-Fired Boilers

Control Technology	Number of Determinations	Emission Limits
Good Combustion Practices	3	0.25 lb/gal
		0.1 tpy
		2.17 lb/hr

RBLC Review
A review of similar units in the RBLC indicates good combustion practices are the principle PM-2.5 control technologies installed on diesel-fired boilers. The lowest PM-2.5 emission rate listed in the RBLC is 0.1 tpy.

Step 1 - Identification of PM-2.5 Control Technology for the Small Diesel-Fired Boilers
From research, the Department identified the following technologies as available for control of PM-2.5 emissions from the small diesel-fired boilers:

(a) Scrubbers
The theory behind scrubbers was discussed in detail in the PM-2.5 BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers scrubbers as a technically feasible control technology for the small diesel-fired boilers.

(b) Limited Operation
The theory behind limited operation was discussed in detail in the NOx BACT for the small diesel-fired boilers and will not be repeated here. The Department considers limited operation a technically feasible control technology for the small diesel-fired boilers.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of PM-2.5 emissions. The Department considers GCPs a technically feasible control technology for the small diesel-fired boilers.

Step 2 - Eliminate Technically Infeasible PM-2.5 Control Technologies for the Diesel-Fired Boilers
All identified control devices are technically feasible for the small diesel-fired boilers.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Small Diesel-Fired Boilers

The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 emissions from the small diesel-fired boilers:

(a) Scrubber (70% - 90% Control)
(c) Good Combustion Practices (Less than 40% Control)
(b) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF provided an economic analysis of the installation of a scrubber. A summary of the analysis is shown below:

Table 4-7. UAF Economic Analysis for Technically Feasible PM-2.5 Controls

Control Alternative	Captured Emissions (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Scrubber	0.01	0.93	$300,000	$42,713	$47,939
Capital Recovery Factor = 0.1424 (7% for a 10 year life cycle)					

UAF contends that the economic analysis indicates the level of PM-2.5 reduction does not justify the use of a scrubber to be used in conjunction with limited operation on the small diesel-fired boilers based on the excessive cost per ton of PM-2.5 removed per year.

UAF proposes the following as BACT for PM-2.5 emissions for the small diesel-fired boilers:

(a) PM-2.5 emissions from the operation of the small diesel-fired boilers will be controlled by limiting the combined operation to no more than 19,650 hours per 12-month rolling period; and

(b) PM-2.5 emissions from the small diesel-fired boilers shall not exceed 7.06 g/MMBtu.

Department Evaluation of BACT for PM-2.5 Emissions from the Small Diesel-Fired Boilers.

The Department reviewed UAF's proposal and finds that the 3 small diesel-fired boilers have a combined potential to emit (PTE) of less than one ton per year (tpy) for PM-2.5 based on a limit on operation of 19,650 hours per 12 month rolling period. The Department does not agree with all of the assumptions made by UAF in their cost analysis. However, the Department believes that at 0.9 tpy, the cost effectiveness in terms of dollars per ton for add-on pollution control for these units is economically infeasible.

Step 5 - Selection of PM-2.5 BACT for the Small Diesel-Fired Boilers

The Department's finding is that BACT for PM-2.5 emissions from the diesel-fired boilers is as follows:

(a) PM-2.5 emissions from the operation of the small diesel-fired boilers will be controlled by limiting the combined operation to no more than 19,650 hours per 12-month rolling period;

(b) PM-2.5 emissions from EUs 19 through 21 shall not exceed 0.012 lb/MMBtu[19]; and

(c) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation.

Table 4-8 lists the proposed PM-2.5 BACT determination for this facility along with those for other small diesel-fired boilers rated at less than 100 MMBtu/hr in the Serious PM-2.5 nonattainment area.

Table 4-8. PM-2.5 BACT Limits for the Small Diesel-Fired Boilers

Facility	Process Description	Capacity	Limitation	Control Method
UAF	3 Diesel-Fired Boilers	< 100 MMBtu/hr	0.012 lb/MMBtu[19]	Limited Operation Good Combustion Practices
Fort Wainwright	27 Diesel-Fired Boilers	< 100 MMBtu/hr	0.012 lb/MMBtu[19]	Good Combustion Practices
Zehnder Facility	2 Diesel-Fired Boilers	< 100 MMBtu/hr	0.012 lb/MMBtu[19]	Good Combustion Practices

4.4 PM-2.5 BACT for the Large Diesel-Fired Engine (EU 8)

Possible PM-2.5 emission control technologies for large diesel-fired engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110-17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 4-9.

Table 4-9. RBLC Summary of PM-2.5 Control for the Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Federal Emission Standards	12	0.03 – 0.02
Good Combustion Practices	28	0.03 – 0.24
Limited Operation	11	0.04 – 0.17
Low Sulfur Fuel	14	0.15 – 0.17
No Control Specified	14	0.02 – 0.15

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices, compliance with the federal emission standards, low ash/sulfur diesel, and limited operation are the principle PM-2.5 control technologies installed on large diesel-fired engines. The lowest PM-2.5 emission rate in the RBLC is 0.02 g/hp-hr.

Step 1 - Identification of PM-2.5 Control Technology for the Large Diesel-Fired Engine
From research, the Department identified the following technologies as available for control of PM-2.5 emissions diesel-fired engines rated at 500 hp or greater:

(a) Diesel Particulate Filter (DPF)
DPF is a control technology that are designed to physically filter particulate matter from the exhaust stream. Several designs exist which require cleaning and replacement of the

filter media after soot has become caked onto the filter media. Regenerative filter designs are also available that burn the soot on a regular basis to regenerate the filter media. The Department considers DPF a technically feasible control technology for the large diesel-fired engine.

(b) Positive Crankcase Ventilation
Positive crankcase ventilation is the process of re-introducing the combustion air into the cylinder chamber for a second chance at combustion after the air has seeped into and collected in the crankcase during the downward stroke of the piston cycle. This process allows any unburned fuel to be subject to a second combustion opportunity. Any combustion products act as a heat sink during the second pass through the piston, which will lower the temperature of combustion and reduce the thermal NOx formation. Positive crankcase ventilation is included in the design of EU 8. The Department considers positive crankcase ventilation a technically feasible control technology for the large diesel-fired engine.

(c) Diesel Oxidation Catalyst (DOC)
DOC can reportedly reduce PM-2.5 emissions by 30% and PM emissions by 50%. A DOC is a form of "bolt on" technology that uses a chemical process to reduce pollutants in the diesel exhaust into decreased concentrations. They replace mufflers on vehicles, and require no modifications. More specifically, this is a honeycomb type structure that has a large area coated with an active catalyst layer. As CO and other gaseous hydrocarbon particles travel along the catalyst, they are oxidized thus reducing pollution. The Department considers DOC a technically feasible control technology for the large diesel-fired engine.

(d) Low Ash Diesel
Residual fuels and crude oil are known to contain ash forming components, while refined fuels are low ash. Fuels containing ash can cause excessive wear to equipment and foul engine components. EU 8 is fired exclusively on distillate fuel which is a form of refined fuel. The potential PM-2.5 emissions are based on emission factors for distillate fuel. EU 8 is capable of firing either diesel or heavy fuel oil (non-low ash fuel) according to manufacturer specifications. The Department considers low ash diesel as a technically feasible control technology for the large diesel-fired engine.

(e) Federal Emission Standards
The theory behind the federal emission standards for EU 8 was discussed in detail in the NOx BACT for the large diesel-fired engine and will not be repeated here. Due to EU 8 not being subject to either 40 C.F.R. 60 Subpart IIII or 40 C.F.R. 63 Subpart ZZZZ the Department does not consider federal emission standards as a feasible control technology for the large diesel-fired engine.

(f) Limited Operation
The theory behind limited operation for EU 8 was discussed in detail in the NOx BACT for the large diesel-fired engine and will not be repeated here. Due to EUs 4 and 8 currently

operating under a combined NOx emission limit, the Department considers limited operation a technically feasible control technology for the large diesel-fired engine.

(g) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of PM-2.5 emissions. The Department considers GCPs a technically feasible control technology for the large diesel-fired engine.

Step 2 - Eliminate Technically Infeasible PM-2.5 Control Technologies for the Large Engine
As explained in Step 1 of Section 4.4, the Department does not consider meeting the federal emission standards as a technically feasible technology to control PM-2.5 emissions from EU 8. Additionally, EU 8 is equipped with SCR for controlling NOx emissions, which creates a backpressure. This backpressure does not allow for the operation of a DPF. Therefore, a DPF is not a technically feasible PM-2.5 control option for the large diesel-fired engine.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Large Diesel-Fired Engine
The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 emissions from the large diesel-fired engines:

(g)	Good Combustion Practices	(Less than 40% Control)
(c)	Diesel Oxidation Catalyst	(30% Control)
(b)	Positive Crankcase Ventilation	(~10% Control)
(d)	Low Ash/Sulfur Diesel	(~20% Control)
(f)	Limited Operation	(0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for PM-2.5 emissions from the large diesel-fired engine:

(a) PM-2.5 emissions from the large diesel-fired engine shall be controlled by operating with positive crankcase ventilation;

(b) PM-2.5 emissions shall not exceed 0.32 g/hp-hr;

(c) EU 8 shall combust only low ash diesel; and

(d) PM-2.5 emissions from EU 8 will be limited by complying with the combined annual NOx emission limit of 40 tons per 12 month rolling period for EUs 4 and 8.

Step 5 - Selection of PM-2.5 BACT for the Large Diesel-Fired Engine
The Department's finding is that the BACT for NOx emissions from the large diesel-fired engine is as follows:

(a) PM-2.5 emissions from EU 8 shall be controlled by operating positive crankcase ventilation at all time of operation;

(b) Limit non-emergency operation of EU 8 to no more than 100 hours per year for maintenance checks and readiness testing;

(c) Combined NOx emissions from EUs 4 and 8 shall not exceed 40 tons per rolling 12 month period;

(d) PM-2.5 emissions from EU 8 shall not exceed 0.32 g/hp-hr over a 3-hour period; and

(e) EU 8 shall combust only low ash diesel.

Table 4-10 lists the proposed BACT determination for this facility along with those for other diesel-fired engines rated at more than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 4-10. Comparison of PM-2.5 BACT for the Large Diesel-Fired Engine at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	Large Diesel-Fired Engine	> 500 hp	0.32 g/hp-hr	Positive Crankcase Ventilation Limited Operation
Fort Wainwright	Large Diesel-Fired Engines	> 500 hp	0.15 – 0.32 g/hp-hr	Limited Operation Ultra-Low Sulfur Diesel Federal Emission Standards
GVEA North Pole	Large Diesel-Fired Engines	> 500 hp	0.32 g/hp-hr	Limited Operation Good Combustion Practices
GVEA Zehnder	Large Diesel-Fired Engines	> 500 hp	0.32 g/hp-hr	Limited Operation Good Combustion Practices

4.5 PM-2.5 BACT for the Small Diesel-Fired Engines (EUs 23, 24, and 26 – 29)

Possible PM-2.5 emission control technologies for small engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 17.210, Small Internal Combustion Engines (<500 hp). The search results for small diesel-fired engines are summarized in Table 4-11.

Table 4-11. RBLC Summary for PM-2.5 Control for the Small Diesel-Fired Engine

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Federal Emission Standards	3	0.15
Good Combustion Practices	19	0.15 – 0.4
Limited Operation	7	0.15 – 0.17
Low Sulfur Fuel	7	0.15 – 0.3
No Control Specified	14	0.02 – 0.09

RBLC Review

A review of similar units in the RBLC indicates low ash/sulfur diesel, compliance with federal emission standards, limited operation, and good combustion practices are the principle PM-2.5 control technologies installed on small diesel-fired engines. The lowest PM-2.5 emission rate listed in the RBLC is 0.02 g/hp-hr.

Step 1 - Identification of PM-2.5 Control Technology for the Small Diesel-Fired Engines

From research, the Department identified the following technologies as available for control of PM-2.5 emissions from the diesel-fired engines rated at 500 hp or less:

(a) Diesel Particulate Filter
The theory behind DPF was discussed in detail in the PM-2.5 BACT for the large diesel-fired engine and will not be repeated here. The Department considers DPF a technically feasible control technology for the small diesel-fired engines.

(b) Diesel Oxidation Catalyst
The theory behind DOC was discussed in detail in the PM-2.5 BACT for the large diesel-fired engines and will not be repeated here. The Department considers DOC a technically feasible control technology for the small diesel-fired engines.

(c) Low Ash Diesel
Residual fuels and crude oil are known to contain ash forming components, while refined fuels are low ash. Fuels containing ash can cause excessive wear to equipment and foul engine components. The Department considers low ash diesel a technically feasible control technology for the small diesel-fired engines.

(d) Federal Emission Standards
The theory behind federal emission standards for the small diesel-fired engine was discussed in detail in the NOx BACT for the small diesel-fired engine and will not be repeated here. The Department considers federal emission standards a technically feasible control technology for the small diesel-fired engines.

(e) Limited Operation
The theory behind limited operation for the small diesel-fired engine was discussed in detail in the NOx BACT for the small diesel-fired engine and will not be repeated here. The Department considers limited operation a technically feasible control technology for the small diesel-fired engines.

(f) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of PM-2.5 emissions. The Department considers GCPs a technically feasible control technology for the small diesel-fired engines.

Step 2 - Eliminate Technically Infeasible PM-2.5 Control Technologies for the Small Engines
All identified control technologies are technically feasible for the small diesel-fired engines.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Small Diesel-Fired Engines
The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 emissions from the small diesel-fired engines:

(a) Diesel Particulate Filter (60% - 90% Control)
(b) Diesel Oxidation Catalyst (40% Control)

(c) Low Ash/ Sulfur Diesel (25% Control)
(f) Good Combustion Practices (Less than 40% Control)
(d) Federal Emission Standards (0% Control)
(e) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF provided an economic analysis for the installation of DPF on EU 27. A summary of the analysis is shown below:

Table 4-12. UAF Economic Analysis for Technically Feasible PM-2.5 Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
DPF	0.26	0.22	$30,751	$4,378	$17,169
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

UAF contends that the economic analysis indicates the level of PM-2.5 reduction does not justify the use of DPF for EU 27 based on the excessive cost per ton of PM-2.5 removed per year.

UAF proposes the following as BACT for PM-2.5 emissions from the small diesel-fired engine EU 27:

(a) PM-2.5 emissions from EU 27 will be controlled by limiting the operation to no more than 4,380 hours per 12-month rolling period;

(b) Comply with the federal emission standards of NSPS Subpart IIII, Tier 3; and

(c) NOx emissions from EU 27 will not exceed 0.11 g/hp-hr.

Department Evaluation of BACT for NOx Emissions from the Small Diesel-Fired Engine
The Department revised the cost analysis provided by UAF for the installation of DPF on EU 27 using a 20 year equipment life. A summary of the analysis is shown below:

Table 4-13. Department Economic Analysis for Technically Feasible PM-2.5 Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
DPF	0.26	0.22	$30,751	$2,891	$13,139
Capital Recovery Factor = 0.094 (7% interest rate for a 20 year equipment life)					

The Department's economic analysis economic analysis indicates the level of PM-2.5 reduction does not justify the use of a DPF to be used in conjunction with the federal emission standards and

limited operation.

Step 5 - Selection of PM-2.5 BACT for the Small Diesel-Fired Engines
The Department's finding is that BACT for PM-2.5 emissions from the small diesel-fired engines is as follows:

(a) Limit operation of EU 27 to no more than 4,380 hours per 12-month rolling period;

(b) Limit non-emergency operation of EUs 24, 28, and 29 to no more than 100 hours per year each for maintenance checks and readiness testing;

(c) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation;

(d) EU 27 shall comply with the federal emission standards of NSPS Subpart IIII, Tier 3; and

(f) Comply with the numerical BACT emission limits listed in Table 4-14.

Table 4-14. Proposed PM-2.5 BACT Limits for the Small Diesel-Fired Engines

EU	Year	Description	Size	Status	BACT Limit	Proposed BACT
23	2003	Detroit Diesel	235 kW	AP-42 Table 3.3-1	1.0 g/hp-hr	Good Combustion Practices
26	1987	Mitsubishi-Bosh	45 kW	AP-42 Table 3.3-1	1.0 g/hp-hr	
27	TBD	Caterpillar C-15	500 hp	Certified Engine	0.11 g/hp-hr	Limit Operation to 4,380 hours per year, Turbo Charger and Aftercooler, & Good Combustion Practices
24	2001	Cummins	51 kW	AP-42 Table 3.3-1	1.0 g/hp-hr	Limit Operation for non-emergency use (100 hours each per year) and Good Combustion Practices
28	1998	Detroit Diesel	120 hp	AP-42 Table 3.3-1	1.0 g/hp-hr	
29	2013	Cummins	314 hp	Certified Engine	0.015 g/hp-hr	

Table 4-15 lists the proposed BACT determination for this facility along with those for other diesel-fired engines rated at less than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 4-15. Comparison of PM-2.5 BACT for the Small Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	Six Small Diesel-Fired Engine	< 500 hp	0.015 – 1.0 g/hp-hr	Good Combustion Practices Limited Operation
Fort Wainwright	41 Small Diesel-Fired Engines	< 500 hp	0.015 – 1.0 g/hp-hr	Good Combustion Practices Limited Operation

4.6 PM-2.5 BACT for the Pathogenic Waste Incinerator (EU 9A)

Possible PM-2.5 emission control technologies for waste incinerators were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 21.300 for Hospital, Medical and Infectious Waste Incinerators. The search results for pathogenic waste incinerators are summarized in Table 4-16.

Table 4-16. RBLC Summary of PM-2.5 Control for Pathogenic Waste Incinerator

Control Technology	Number of Determinations	Emission Limits (lb/hr)
Multiple Chamber Design	1	0.0400

RBLC Review
A review of similar units in the RBLC indicates multiple chamber design is the principle PM-2.5 control technology installed on pathogenic waste incinerators. The lowest emission rate listed in the RBLC is 0.0400 lb/hr

Step 1 - Identification of PM-2.5 Control Technology for the Pathogenic Waste Incinerator
From research, the Department identified the following technologies as available for control of PM-2.5 emissions from pathogenic waste incinerators:

(a) Fabric Filters
The theory behind fabric filters was discussed in detail in the PM-2.5 BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers fabric filters a technically feasible control technology for the pathogenic waste incinerator.

(b) ESPs
The theory behind ESPs was discussed in detail in the PM-2.5 BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers ESPs a technically feasible control technology for the pathogenic waste incinerator.

(c) Multiple Chambers
A multiple chamber incinerator introduces the waste material and a portion of the combustion air in the primary chamber. The waste material is combusted in the primary chamber. The secondary chamber introduces the remaining air to complete the combustion of all incomplete combustion products. Many of the volatile organic compounds from waste material are completely combusted in the secondary chamber. Solid waste incinerators can reduce PM-10 emissions up to 70 percent using multiple chambers. The expectation is that less than 70 percent control of PM-2.5 would be removed. The Department considers multiple chambers a technically feasible control technology for the pathogenic waste incinerator.

(d) Limited Operation
The theory behind the limited operation for EU 9A was discussed in detail in the NOx BACT for the pathogenic waste incinerator and will not be repeated here. The Department considers limited operation a technically feasible control technology for the pathogenic waste incinerator.

(e) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of PM-2.5 emissions. The Department considers GCPs a technically feasible control technology for the pathogenic waste incinerator.

Step 2 - Eliminate Technically Infeasible PM-2.5 Controls for Pathogenic Waste Incinerator
The applicant provided information from the manufacturer of the pathogenic waste incinerator that an ESP is a technically infeasible PM-2.5 control for the pathogenic waste incinerator due to the high moisture content of the exhaust.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Pathogenic Waste Incinerator
The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 emissions from the pathogenic waste incinerator:

(a) Fabric Filter (99.9% Control)
(e) Good Combustion Practices (Less than 40% Control)
(c) Multiple Chambers (0% Control)
(d) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF provided an economic analysis for the installation of a fabric filter. A summary of the analysis is shown below:

Table 4-17. UAF Economic Analysis for Technically Feasible PM-2.5 Controls

Control Alternative	Captured Emissions (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Fabric Filter	0.01	0.24	$1,300,000	$217,011	$761,441
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

UAF contends that the economic analysis indicates the level of PM-2.5 reduction does not justify the use of a fabric filter in conjunction with the multiple chamber design and limited operation based on the excessive cost per ton of PM-2.5 removed per year.

UAF proposes the following as BACT for PM-2.5 emissions from the pathogenic waste incinerator:

(a) PM-2.5 emissions from the operation of EU 9A will be controlled with a multiple chamber design and by limiting operation to no more than 109 tons of waste combusted per 12-month rolling period;

(b) PM-2.5 emissions from EU 9A shall not exceed 4.67 lb/ton; and

(c) Compliance with the operating hours limit will be demonstrated by monitoring and recording the weight of waste combusted on a monthly basis.

Step 5 - Selection of PM-2.5 BACT for the Pathogenic Waste Incinerator
The Department's finding is that BACT for PM-2.5 emissions from the pathogenic waste incinerator is as follows:

(a) PM-2.5 emissions from EU 9A shall be controlled with a multiple chamber design;

(b) PM-2.5 emissions from EU 9A shall not exceed 4.67 lb/ton;

(c) Limit the operation of EU 9A to 109 tons of waste combusted per 12 month rolling period;

(d) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation; and

(e) Compliance with the proposed operational limit will be demonstrated by recording pounds of waste combusted for the pathogenic waste incinerator.

Table 4-18 lists the proposed BACT determination for this facility along with those for other waste incinerators located in the Serious PM-2.5 nonattainment area.

Table 4-18. Comparison of PM-2.5 BACT for Pathogenic Waste Incinerators at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	One Pathogenic Waste Incinerator	83 lb/hr	4.67 lb/ton	Multiple Chambers Good Combustion Practices Limited Operation

4.7 PM-2.5 BACT for the Material Handling Units (EUs 105, 107, 109 through 111, 114, and 128 through 130)

Possible PM-2.5 emission control technologies for material handling were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 99.100 - 190, Fugitive Dust Sources. The search results for material handling units are summarized in Table 4-19.

Table 4-19. PM-2.5 Control for Material Handling Units

Control Technology	Number of Determinations	Emission Limits
Fabric Filter / Baghouse	10	0.005 gr/dscf
Electrostatic Precipitator	3	0.032 lb/MMBtu
Wet Suppressants / Watering	3	29.9 tpy
Enclosures / Minimizing Drop Height	4	0.93 lb/hr

RBLC Review
A review of similar units in the RBLC indicates good operational practices, enclosures, fabric filters, and minimizing drop heights are the principle PM-2.5 control technologies for material handling operations.

Step 1 - Identification of PM-2.5 Control Technology for the Material Handling Units
From research, the Department identified the following technologies as available for PM-2.5 control of the material handling units:

(a) Fabric Filters
The theory behind fabric filters was discussed in detail in the PM-2.5 BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers fabric filters a technically feasible control technology for EUs 105, 107, 109, 110, 114, and 128 through 130. The ash unloading to disposal trucks (EU 111) occurs in a building with large doors. During ash unloading the doors remain closed to prevent the release of fugitive emissions.

Therefore, the Department does not consider a fabric filter a technically feasible control technology for EU 111.

(b) Scrubbers
The theory behind scrubbers was discussed in detail in the PM-2.5 BACT for the large dual fuel-fired boiler and will not be repeated here. The Department considers scrubbers a feasible control technology for the material handling units, except for EU 111. EU 111 does not have collected emissions and therefore a scrubber is not considered a technically feasible control technology.

(c) Suppressants
The use of dust suppression to control particulate matter can be effective for stockpiles and transfer points exposed to the open air. Applying water or a chemical suppressant can bind the materials together into larger particles which reduces the ability to become entrained in the air either from wind or material handling activities. The Department considers the use of suppressants a technically feasible control technology for all of the material handling units.

(d) Enclosures
An enclosure prevents the release of fugitive emissions into the ambient air by confining all fugitive emissions within a structure and preventing additional fugitive emissions from being generated from winds eroding stockpiles and lifting particulate matter from conveyors. Often enclosures are paired with fabric filters. The RBLC does not identify a control efficiency for an enclosure that is not associated with another control option. The Department considers enclosures a technically feasible control technology for the material handling units.

(e) Wind Screens
A wind screen is similar to a solid fence which is used to lower wind velocities near stockpiles and material handling sites. As wind speeds increase, so do the fugitive emissions from the stockpiles, conveyors, and transfer points. The use of wind screens is appropriate for materials not already located in enclosures. Due to all of the material handling units being operated in enclosures the Department does not consider wind screens a technically feasible control option for the material handling units.

(f) Vents/Closed System Vents/Negative Pressure Vents
Vents can control fugitive emissions by collecting fugitive emissions from enclosed loading, unloading, and transfer points and then venting emissions to the atmosphere or back into other equipment such as a storage silo. Other vent control designs include enclosing emission units and operating under a negative pressure. The Department considers vents to be a technically feasible control technology for the material handling units, except for EU 111. EU 111 does not have collected emissions and the vent system would be ineffective when trucks enter and departed the loading area.

Step 2 - Eliminate Technically Infeasible PM-2.5 Controls for the Material Handling Units
As explained in Step 1 of Section 4.7, the Department does not consider fabric filters, scrubbers, and vents as technically feasible PM-2.5 control technologies for EU 111. The Department does not consider wind screens as technically feasible PM-2.5 control technologies for the material handling units.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Material Handling Units
The following control technologies have been identified and ranked for control of particulates from the material handling equipment:

(a)	Fabric Filters	(50 - 99% Control)
(d)	Enclosures	(50 - 99% Control)
(b)	Scrubber	(50% - 99% Control)
(e)	Cyclone	(20% - 70% Control)
(c)	Suppressants	(less than 90% Control)
(f)	Vents	(less than 90% Control)

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for PM-2.5 emissions from the material handling units:

(a) PM-2.5 emissions from EUs 105, 107, 109 through 111, 114, and 128 through 130 will be controlled by enclosing each EU.

(b) PM-2.5 emissions from the operation of the material handling units, except EU 111, will be controlled by installing, operating, and maintaining fabric filters and vents.

(c) PM-2.5 emissions from EUs 105, 107, 109, 110, and 128 through 130 shall not exceed 0.003 gr/dscf.

(d) PM-2.5 emissions from EU 111 shall not exceed 5.5×10^{-5} lb/ton.

(e) PM-2.5 emissions from EU 114 shall not exceed 0.05 gr/dscf.

Step 5 - Selection of PM-2.5 BACT for the Material Handling Units
The Department's finding is that BACT for PM-2.5 emissions from the material handling equipment is as follows:

(a) PM-2.5 emissions from EUs 105, 107, 109 through 111, 114, and 128 through 130 will be controlled by enclosing each EU;

(b) PM-2.5 emissions from the operation of the material handling units, except EU 111, will be controlled by installing, operating, and maintaining fabric filters and vents;

(c) PM-2.5 emissions from EUs 105, 107, 109, 110, and 128 through 130 shall not exceed 0.003 gr/dscf;

(d) PM-2.5 emissions from EU 111 shall not exceed 5.5×10^{-5} lb/ton;

(e) PM-2.5 emissions from EU 114 shall not exceed 0.05 gr/dscf; and

(f) Initial compliance with the emission rates for the material handling units, except EU 111, will be demonstrated with a performance test to obtain an emission rate.

Table 4-20. PM-2.5 BACT Control Technologies Proposed for the Material Handling Units

Facility	Process Description	Capacity	Limitation	Control Method
UAF	7 Material Handling Units	Varies	0.003 gr/dcf	Fabric Filter & Enclosure & Vent
UAF	Ash Loadout to Truck (EU 111)	N/A	5.50E-05 lb/ton	Enclosure
UAF	Dry Sorbent Handing Vent Filter Exhaust	5 acfm	0.050 gr/dcf	Fabric Filter & Enclosure & Vent

5. BACT DETERMINATION FOR SO_2

The Department based its SO_2 assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by GVEA for the North Pole Power Plant and Zehnder Facility, Aurora for the Chena Power Plant, US Army for Fort Wainwright, and UAF for the Combined Heat and Power Plant.

5.1 SO_2 BACT for the Large Dual Fuel-Fired Boiler (EU 113)

Possible SO_2 emission control technologies for the large dual fuel-fired boiler were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.110, Coal Combustion in Industrial Size Boilers and Furnaces. The search results are summarized in Table 5-1.

Table 5-1: RBLC Summary of SO_2 Control for Industrial Coal-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Flue Gas Desulfurization / Scrubber / Spray Dryer	10	0.06 – 0.12
Limestone Injection	10	0.055 – 0.114
Low Sulfur Coal	4	0.06 – 1.2

RBLC Review

A review of similar units in the RBLC indicates flue gas desulfurization and low sulfur coal are the principle SO_2 control technologies installed on large dual fuel-fired boilers. The lowest SO_2 emission rate in the RBLC is 0.055 lb/MMBtu

Step 1 - Identification of SO_2 Control Technology for the Large Dual Fuel-Fired Boiler

From research, the Department identified the following technologies as available for control of SO_2 emissions from the large dual fuel-fired boiler:

(a) Flue Gas Desulfurization (FGD)/Scrubber/Spray Dryer
Two basic types of FGD systems exist, dry and wet scrubbing. In the wet scrubbing system, flue gas is contacted with a solution or slurry of alkaline material in a vessel providing a relatively long residence time. Generally, particulate matter has not been removed prior to entering into the adsorber, and the spray drying process acts as a combined SO_2/PM removal system. The SO_2 in the flue reacts with the alkali solution or slurry by adsorption and/or absorption mechanisms to form liquid-phase salts. These salts are dried to about one percent free moisture by the heat in the flue gas. These solids are entrained in the flue gas and carried from the dryer to a PM collection device, such as a baghouse.

Spray drying technology is less complex mechanically, and no more complex chemically, than wet scrubbing systems. The main advantages of the spray dryer is that this technology avoids two problems associated with wet scrubbing, corrosion and liquid waste treatment. A PM collection device is also required for dry scrubbing.

The vendor for the large dual fuel-fired boiler, Babcock & Wilcox, indicated that this new boiler design can accommodate a wet or dry FGD system. The wet FGD system is a spray dry adsorber (SDA) that would be located at grade between the air heater and the baghouse. The current baghouse and filter media is capable of handling the higher solids loading from an SDA. The system would utilize a baghouse fly ash recycle system which would activate a portion of the un-reacted lime in the fly ash. The recycled slurry, when sprayed through the atomizer, will reduce the SO_2 emissions, possibly without the need for any additional reagent depending on the level of SO_2 reduction required. The proposed SDA technology is expected to achieve an SO_2 emission rate of 0.04 lb/MMBtu, which is approximately 92 percent SO_2 control. The Department considers SDA a technically feasible control technology for the large dual fuel-fired boiler.

Babcock & Wilcox indicated that the large dual fuel-fired boiler design should include a small dry sorbent injection (DSI) system to reduce hydrofluoric acid (HF) and hydrochloric acid (HCl) emissions. This small DSI system is not designed for and is not expected to control SO_2 emissions. An add-on DSI system would be required for SO_2 control.

An add-on DSI system is possible and would use sodium bicarbonate or specialized hydrated lime as a reagent to react with SO_2. This form of a dry FDG system would likely require a silo for reagent storage, a mill building, pneumatic conveying, and reagent distribution upstream of the baghouse. Potentially, the baghouse ash handling system capacity would also need to be increased, depending on the sorbent injection rate. The add-on DSI system could achieve approximately a 75 percent SO_2 control. The Department considers an add-on DSI system for SO_2 emissions control to be a feasible control technology for the large dual fuel-fired boiler.

(b) Limestone Injection

In the limestone injection process, crushed coal and limestone are suspended in a boiler by an upward stream of hot air. The coal is burned in this bubbling fluidized mixture. The temperature in the combustion chamber of between 1,500 and 1,600 degrees is the correct temperature for the limestone to react with SO_2 to form a solid compound that is collected in a particulate matter collection device. The sulfur reduction can be achieved with either limestone or hydrated lime. Limestone injection technology has the benefits of low capital costs, low feed rates, and low operating costs.

The CFB design of the large dual fuel-fired boiler is capable of using limestone as part of the feed bed which controls the sulfur emissions released during coal combustion. The proposed fabric filter baghouse system would remove the particulate matter formed as calcium sulfate. The Department considers limestone injection a technically feasible control technology for the large dual fuel-fired boiler.

(c) Low Sulfur Coal
UAF purchases coal from the Usibelli Coal Mine located in Healy, Alaska. This coal mine is located 115 miles south of Fairbanks. The coal mined at Usibelli is sub-bituminous coal and has a relatively low sulfur content with guarantees of less than 0.4 percent by weight. Usibelli Coal Data Sheets indicate a range of 0.08 to 0.28 percent Gross As Received (GAR) percent Sulfur (%S). According to the U.S. Geological Survey, coal with less than one percent sulfur is classified as low sulfur coal. The Department considers the use of low sulfur coal a technically feasible control technology for the large dual fuel-fired boiler.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the large dual fuel-fired boiler.

Step 2 - Eliminate Technically Infeasible SO_2 Controls for the Large Dual Fuel-Fired Boiler
All identified control technologies are technically feasible for the large dual fuel-fired boiler.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Large Dual Fuel-Fired Boiler
The following control technologies have been identified and ranked by efficiency for control of SO_2 emissions from the large dual fuel-fired boiler:

(a-1)	Wet Scrubber	(99% Control)
(a-2)	Spray Dry Absorbers	(92% Control)
(a-3)	Dry Sorbent Injection	(75% Control)
(d)	Good Combustion Practices	(Less than 40% Control)
(b)	Limestone Injection	(0% Control)
(c)	Low Sulfur Coal	(0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF provided an economic analysis of the installation of wet and dry scrubber systems. A summary of the analysis is shown below:

Table 5-2. UAF Economic Analysis for Technically Feasible SO_2 Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Spray Dry Absorber	258.9	238.2	$15,600,000	$3,270,753	$13,732
Dry Sorbent Injection	258.9	194.2	$2,535,000	$1,697,487	$8,742
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

UAF contends that the economic analysis indicates the level of SO_2 reduction does not justify the use of spray dry absorbers or dry-sorbent injection for the dual fuel-fired boiler based on the excessive cost per ton of SO_2 removed per year.

UAF proposes the following as BACT for SO_2 emissions from the dual fuel-fired boiler:

(a) SO_2 emissions from the operation of EU 113 will be controlled by the operation of limestone injection at all times the unit is in operation;

(b) SO_2 emissions from EU 113 will be controlled by burning low sulfur coal at all times the dual fuel-fired boiler is combusting coal; and

(c) SO_2 emissions from EU 113 will not exceed 0.2 lb/MMBtu.

Department Evaluation of BACT for SO_2 Emissions from the Dual Fuel-Fired Boiler
The Department revised the cost analyses provided for the installation of spray dry absorbers and dry sorbent injection and created a new cost analysis for wet scrubbers, all using the unrestricted potential to emit for the dual fuel-fired boiler, a baseline emission rate of 0.2 lb SO_2/MMBtu,[21] a retrofit factor of 1.0 for a retrofit of average difficulty, a SO_2 removal efficiency of 99%, 90%, and 80% for spray dry absorbers and dry sorbent injection respectively, and a 15 year equipment life. A summary of the analysis is shown below:

Table 5-3. Department Economic Analysis for Technically Feasible SO_2 Controls

Control Alternative	Potential to Emit (PTE)	Emission Reduction (tpy)	Total Capital Cost ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber	259	257	$29,487,290	$6,081,181	$23,690
SDA	259	233	$27,132,570	$5,463,391	$23,411
DSI	259	207	$5,192,915	$1,731,023	$8,345
Capital Recovery Factor = 0.0996 (5.5% interest rate for a 15 year equipment life)					

The Department's economic analysis indicates the level of SO_2 reduction justifies the use of dry sorbent injection as BACT for the dual fuel-fired boiler located in the Serious PM-2.5 nonattainment area.

Step 5 - Selection of SO_2 BACT for the Large Dual Fuel-Fired Boiler
The Department's finding is that BACT for SO_2 emissions from the dual fuel-fired boilers is as follows:

(a) SO_2 emissions from EU 113 shall be controlled by operating and maintaining dry sorbent injection and limestone injection at all times the unit is in operation;

(b) EU 113 shall not exceed a SO_2 emission rate of 0.10 lb/MMBtu[22] averaged over a 3-hour period;

[21] Emission rate is SO_2 limit from 40 C.F.R. 60.42b(k)(1) [NSPS Subpart Db]
[22] BACT limit selected after evaluating existing emission limits in the RBLC database for coal-fired boilers, taking into account previous source test data from coal-fired boilers in Alaska and actual emissions data from other sources

(c) SO_2 emissions from EU 113 will be controlled by burning low sulfur coal at all times the dual fuel-fired boiler is combusting coal;

(d) Maintain good combustion practices at all times of operation by following the manufacturer's operating and maintenance procedures; and

(e) Initial compliance with the proposed SO_2 emission rate for the dual fuel-fired boilers will be demonstrated by conducting a performance test to obtain an emission rate.

Table 5-4 lists the proposed SO_2 BACT determination for this facility along with those for other coal-fired boilers in the Serious PM-2.5 nonattainment area.

Table 5-4. Comparison of SO_2 BACT for Coal-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.10 lb/MMBtu[22]	Dry Sorbent Injection Limestone Injection Low Sulfur Coal
Fort Wainwright	Six Coal-Fired Boilers	1,380 MMBtu/hr (combined)	0.10 lb/MMBtu	Low Sulfur Coal Dry Sorbent Injection Operational Limit
Chena	Four Coal-Fired Boilers	497 MMBtu/hr (combined)	0.10 lb/MMBtu	Dry Sorbent Injection Low Sulfur Coal

5.2 SO_2 BACT for the Mid-Sized Diesel-Fired Boilers (EUs 3 and 4)

Possible SO_2 emission control technologies for mid-sized diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.220, Industrial Size Distillate Fuel Oil Boilers (>100 MMBtu/hr and ≤ 250 MMBtu/hr). The search results for mid-sized diesel-fired boilers are summarized in Table 5-5.

Table 5-5. RBLC Summary of SO_2 Control for Mid-Sized Boilers Firing Diesel

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
No Control Specified	2	0.0006

Possible SO_2 emission control technologies for mid-sized diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.310, Industrial Size Gaseous Fuel Boilers (>100 MMBtu/hr and ≤ 250 MMBtu/hr). The search results for mid-sized diesel-fired boilers are summarized in Table 5-6.

Table 5-6. RBLC Summary of SO_2 Control for Mid-Sized Boilers Firing Natural Gas

employing similar types of controls, using manufacturer data provided by Babcock & Wilcox, and in-line with EPA's pollution control Fact Sheets while keeping in mind that BACT limits must be achievable at all times.

Control Technology	Number of Determinations	Emission Limits
Low Sulfur Fuel	2	0.89 - 11.24 (tpy)
Good Combustion Practices	5	0.03 – 0.18 (lb/hr)
No Control Specified	4	0.01 – 0.09 (lb/hr)

RBLC Review
A review of similar units in the RBLC indicates low sulfur fuel and good combustion practices are the principle SO_2 control technologies installed on mid-sized boilers. The lowest SO_2 emission rate listed in the RBLC is 0.0006 lb/MMBtu.

Step 1 - Identification of SO_2 Control Technology for the Mid-Sized Diesel-Fired Boilers
From research, the Department identified the following technologies as available for SO_2 control for the mid-sized diesel-fired boilers:

(a) Ultra Low Sulfur Diesel
ULSD has a fuel sulfur content of 0.0015 percent sulfur by weight or less. Using ULSD would reduce SO_2 emissions because the mid-sized diesel-fired boilers are combusting standard diesel that has a sulfur content of up to 0.5 percent sulfur by weight. Switching to ULSD could reach a great than 99 percent decrease in SO_2 emissions from the mid-sized diesel-fired boilers. The Department considers ULSD a technically feasible control technology for the mid-sized diesel-fired boilers.

(b) Natural Gas
The theory of operating the mid-sized diesel-fired boilers on natural gas was discussed in detail in the NOx BACT for the mid-sized diesel-fired boilers and will not be repeated here. The Department does not consider operating the mid-sized diesel-fired boilers on natural gas as a technically feasible control technology.

(c) Limited Operation
The theory of limited operation for the mid-sized diesel-fired boilers was discussed in detail in the NOx BACT for the mid-sized diesel-fired boilers and will not be repeated here. The Department considers limited operation a technically feasible control technology for the mid-sized diesel-fired boilers.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the mid-sized diesel-fired boilers.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for the Mid-Sized Diesel-Fired Boilers
Limited operation for EU 3 is a technically infeasible control technology as it is a backup unit.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Mid-Sized Diesel-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from themed-sized diesel-fired boilers.

(a) Ultra Low Sulfur Diesel (99% Control)
(d) Good Combustion Practices (Less than 40% Control)
(c) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for SO_2 emissions from the mid-sized diesel-fired boilers:

(a) SO_2 emissions from EUs 3 and 4 shall combust ULSD while firing diesel fuel;

(b) SO_2 emissions from EU 4 shall not exceed 0.60 lb/MMscf while firing natural gas; and

(c) SO_2 emissions from EU 4 will be limited by complying with the combined annual NOx emission limit of 40 tons per 12 month rolling period for EUs 4 and 8.

Step 5 - Selection of SO_2 BACT for the Mid-Sized Diesel-Fired Boilers

The Department's finding is that BACT for SO_2 emissions from the mid-sized diesel-fired boilers is as follows:

(a) SO_2 emissions from EUs 3 and 4 shall be controlled by only combusting ULSD when firing diesel fuel;

(b) SO_2 emissions from EU 4 will be limited by complying with the combined annual NOx emission limit of 40 tons per 12 month rolling period for EUs 4 and 8;

(c) SO_2 emissions from EU 4 while firing natural gas shall not exceed 0.60 lb/MMscf;

(d) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of operation; and

(e) Compliance with the proposed SO_2 emission limit will be demonstrated through fuel shipment receipts and/or fuel testing for sulfur content.

Table 5-7 lists the proposed BACT determination for this facility along with those for other mid-sized diesel-fired boilers located in the Serious PM-2.5 nonattainment area.

Table 5-7. Comparison of SO_2 BACT for the Mid-Sized Diesel-Fired Boilers at Nearby Power Plants

Facility	EU ID	Process Description	Capacity	Fuel	Limitation	Control Method
UAF	3	Dual Fuel-Fired Boilers	100 – 250 MMBtu/hr	Diesel	15 ppmw S in fuel	Ultra Low Sulfur Diesel
	4			Diesel	15 ppmw S in fuel	Limited Operation
				Natural Gas	0.60 lb/MMscf	Ultra Low Sulfur Diesel

5.3 SO_2 BACT for the Small Diesel-Fired Boilers (EUs 19 through 21)

Possible SO_2 emission control technologies for small diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code

13.220, Commercial/Institutional Size Boilers (<100 MMBtu/hr). The search results for small diesel-fired boilers are summarized in Table 5-8.

Table 5-8. RBLC Summary of SO_2 Control for Small Diesel-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Low Sulfur Content	5	0.0036 – 0.0094
Good Combustion Practices	4	0.0005
No Control Specified	5	0.0005

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and combustion of low sulfur fuel are the principle SO_2 control technologies installed on small diesel-fired boilers. The lowest SO_2 emission rate listed in the RBLC is 0.0005 lb/MMBtu

Step 1 - Identification of SO_2 Control Technology for the Small Diesel-Fired Boilers
From research, the Department identified the following technologies as available for SO_2 control for the small diesel-fired boilers:

(a) ULSD
The theory of ULSD was discussed in detail in the SO_2 BACT for the mid-sized diesel-fired boilers and will not be repeated here. The Department considers ULSD a technically feasible control technology for the small diesel-fired boilers.

(b) Limited Operation
The theory behind limited operation was discussed in detail in the NOx BACT for the small diesel-fired boilers and will not be repeated here. The Department considers limited operation as a technically feasible control technology for the small diesel-fired boilers.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2. The Department considers GCPs a technically feasible control technology for the small diesel-fired boilers.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for the Small Diesel-Fired Boilers
All identified control technologies are technically feasible for the diesel-fired boilers.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Small Diesel-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from the small diesel-fired boilers:

(a) Ultra Low Sulfur Diesel (99% Control)
(c) Good Combustion Practices (Less than 40% Control)
(b) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for SO_2 emissions from the small diesel-fired boilers:

(a) SO_2 emissions from the operation of the small diesel-fired boilers will be controlled by limiting the combined operation to no more than 19,650 hours per 12-month rolling period;

(b) SO_2 emissions from the operation of the small diesel-fired boilers shall be controlled by using ULSD (0.0015 sulfur by weight) at all times of operation; and

(c) Compliance with the proposed SO_2 emission limit will be demonstrated through fuel shipment receipts and/or fuel testing for sulfur content.

Step 5 - Selection of SO_2 BACT for the Small Diesel-Fired Boilers

The Department's finding is that BACT for SO_2 emissions from the diesel-fired boilers is as follows:

(a) SO_2 emissions from EUs 19-21 shall be controlled by limited the combined operation to no more than 19,650 hours per 12-month rolling period;

(b) SO_2 emissions from the diesel-fired boilers shall be controlled by only combusting ULSD; and

(c) Compliance will be demonstrated with fuel shipment receipts and/or fuel tests for sulfur content.

Table 5-9 lists the proposed SO_2 BACT determination for this facility along with those for other small diesel-fired boilers rated at less than 100 MMBtu/hr in the Serious PM-2.5 nonattainment area.

Table 5-9. Comparison of SO_2 BACT for the Small Diesel-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Limited Operation Good Combustion Practices Ultra-Low Sulfur Diesel
	Waste Fuel-Fired Boilers		0.5 % S by weight	Good Combustion Practices
UAF	3 Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Limited Operation Ultra-Low Sulfur Diesel
GVEA Zehnder	2 Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel

5.4 SO_2 BACT for the Large Diesel-Fired Engine (EU 8)

Possible SO_2 emission control technologies for large engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.100 - 17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 5-10.

Table 5-10. RBLC Summary Results for SO_2 Control for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Low Sulfur Diesel	27	0.005 – 0.02
Federal Emission Standards	6	0.001 – 0.005
Limited Operation	6	0.005 – 0.006
Good Combustion Practices	3	None Specified
No Control Specified	11	0.005 – 0.008

RBLC Review
A review of similar units in the RBLC indicates combustion of low sulfur fuel, limited operation, and good combustion practices are the principle SO_2 control technologies installed on large diesel-fired engines. The lowest emission rate listed in the RBLC is 0.001 g/hp-hr.

Step 1 - Identification of SO_2 Control Technology for the Large Diesel-Fired Engine
From research, the Department identified the following technologies as available for the control of SO_2 emissions from the large diesel-fired engine:

(a) Ultra Low Sulfur Diesel
The theory of ULSD was discussed in detail in the SO_2 BACT for the mid-sized diesel-fired boilers and will not be repeated here. The Department considers ULSD a technically feasible control technology for the large diesel-fired engine.

(b) Federal Standards
The theory of federal emission standards was discussed in detail in the NOx BACT for the large diesel-fired engine and will not be repeated here. The Department does not consider federal emission standards a technically feasible control technology for the large diesel-fired engine.

(c) Limited Operation
The theory of limited operation for EU 8 was discussed in detail in the NOx BACT for the large diesel-fired engine and will not be repeated here. The Department considers limited operation as a technically feasible control technology for the large diesel-fired engine.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the large diesel-fired engine.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for the Large Diesel-Fired Engine
As explained in Step 1 of Section 5.4, the Department does not consider federal emission standards as a technically feasible control technology to control SO_2 emissions from the large diesel-fired engine.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Large Diesel-Fired Engine

(a) Ultra Low Sulfur Diesel (99% Control)

(d) Good Combustion Practices (Less than 40% Control)
(c) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for SO_2 emissions from the large diesel-fired engine:

(a) SO_2 emissions from EU 8 shall be controlled by combusting ULSD (0.0015 weight percent sulfur); and

(b) SO_2 emissions from EU 8 will be limited by complying with the combined annual NOx emission limit of 40 tons per 12 month rolling period for EUs 4 and 8.

Step 5 - Selection of SO_2 BACT for the Large Diesel Fired-Engine

The Department's finding is that BACT for SO_2 emissions from the large diesel-fired engines is as follows:

(a) SO_2 emissions from EU 8 shall be controlled by combusting only ULSD (0.0015 weight percent sulfur);

(b) Limit the combined operation of EU 4 and 8 to no more than 40 tons of NOx per 12 month rolling average;

(c) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of operation; and

(d) Compliance will be demonstrated with fuel shipment receipts and/or fuel tests for sulfur content.

Table 5-11 lists the proposed BACT determination for this facility along with those for other diesel-fired engines rated at more than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 5-11. Comparison of SO_2 BACT for Large Diesel-Fired Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	8 Large Diesel-Fired Engines	> 500 hp	15 ppmw S in fuel	Limited Operation Good Combustion Practices Ultra-Low Sulfur Diesel
UAF	Large Diesel-Fired Engine	13,266 hp	15 ppmw S in fuel	Limited Operation Good Combustion Practices Ultra-Low Sulfur Diesel
GVEA North Pole	Large Diesel-Fired Engine	600 hp	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp	500 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel

5.5 SO_2 BACT for the Small Diesel-Fired Engines (EUs 23, 24, and 26 – 29)

Possible SO_2 emission control technologies for small engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 17.210, Small Internal Combustion Engines (<500 hp). The search results for small diesel-fired engines are summarized in Table 5-12.

Table 5-12. RBLC Summary of SO_2 Controls for Small Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Low Sulfur Diesel	6	0.005 – 0.02
No Control Specified	3	0.005

RBLC Review
A review of similar units in the RBLC indicates combustion of low sulfur fuel is the principle SO_2 control technology for small diesel-fired engines. The lowest SO_2 emission rate listed in the RBLC is 0.005 g/hp-hr.

Step 1 - Identification of SO_2 Control Technology for the Small Diesel-Fired Engines
From research, the Department identified the following technologies as available for control of SO_2 emissions from diesel-fired engines rated at less than 500 hp:

(a) Ultra Low Sulfur Diesel
The theory of ULSD was discussed in detail in the SO_2 BACT for the mid-sized diesel-fired boilers and will not be repeated here. The Department considers ULSD a technically feasible control technology for the small diesel-fired engines.

(b) Limited Operation
The theory of limited operation for EU 27 was discussed in detail in the NOx BACT for the small diesel-fired engine and will not be repeated here. The Department considers limited operation a technically feasible control technology for the small diesel-fired engines.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The department considers GCPs a technically feasible control technology for the small diesel-fired engines.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for the Small Engines
All identified control technologies are technically feasible for the small diesel-fired engines.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Small Diesel-Fired Engines
The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from the small diesel-fired engines.

(a) Ultra Low Sulfur Diesel (99% Control)
(c) Good Combustion Practices (Less than 40% Control)
(c) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for SO_2 emissions from the small diesel-fired engine EU 27:

(a) SO_2 emissions from the operation of the small diesel-fired engine shall be controlled by using ULSD at all times of operation (0.0015 weight percent sulfur); and

(b) SO_2 emissions from the operation of the small diesel-fired engine will be controlled by limiting operation to no more than 4,380 hours per 12-month rolling period.

Department Evaluation of BACT for SO_2 Emissions from Small Diesel-Fired Engines

The Department reviewed UAF's proposal and found that in addition to combusting only ULSD, and limiting operation of the small diesel-fired engine, good combustion practices is BACT for SO_2.

Step 5 - Selection of SO_2 BACT for the Small Diesel-Fired Engines

The Department's finding is that BACT for SO_2 emissions from the small diesel-fired engines is as follows:

(a) SO_2 emissions from small diesel-fired engines shall be controlled by combusting only ULSD at all times of operation;

(b) SO_2 emissions from the operation of EU 27 will be controlled by limiting operation to no more than 4,380 hours per 12-month rolling period;

(c) Limit non-emergency operation of EUs 24, 28, and 29 to no more than 100 hours per year each for maintenance checks and readiness testing;

(d) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation;

(e) Compliance will be demonstrated with fuel shipment receipts and/or fuel tests for sulfur content; and

(f) Compliance with the operating hours limit will be demonstrated by monitoring and recording the number of hours operated on a monthly basis.

Table 5-13 lists the proposed BACT determination for this facility along with those for other diesel-fired engines rated at less than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 5-13. Comparison of SO_2 BACT for Small Diesel-Fired Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	41 Small Diesel-Fired Engines	< 500 hp	15 ppmw S in fuel	Limited Operation Ultra-Low Sulfur Diesel Good Combustion Practices
UAF	Six Small Diesel-Fired Engine	< 500 hp	15 ppmw S in fuel	Limited Operation

Facility	Process Description	Capacity	Limitation	Control Method
				Federal Emission Standards Ultra-Low Sulfur Diesel

5.6 SO_2 BACT for the Pathogenic Waste Incinerator (EU 9A)

Possible SO_2 emission control technologies for pathogenic waste incinerators were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 21.300 for Hospital, Medical, and Infectious Waste Incinerators. The search results for pathogenic waste incinerators are summarized in Table 5-14.

Table 5-14. RBLC Summary of SO_2 Control for the Pathogenic Waste Incinerator

Control Technology	Number of Determinations	Emission Limits (lb/hr)
Natural Gas	1	0.0500

RBLC Review
A review of similar units in the RBLC indicates use of natural gas as fuel is the principle SO_2 control technology installed on pathogenic waste incinerators. The lowest emission rate listed in the RBLC is 0.0500 lb/hr.

Step 1 - Identification of SO_2 Control Technology for the Pathogenic Waste Incinerator
From research, the Department identified the following technologies as available for control of SO_2 emissions from pathogenic waste incinerators:

(a) Natural Gas
Natural gas combustion has a lower SO_2 emission rate than standard diesel combustion and can be a preferred fuel for this reason. The availability of natural gas in Fairbanks can be limited. The Department considers natural gas as a technically feasible control option for the pathogenic waste incinerator.

(b) Ultra Low Sulfur Diesel
The theory of ULSD was discussed in detail in the SO_2 BACT for the mid-sized diesel-fired boilers and will not be repeated here. The Department considers ULSD a technically feasible control technology for the pathogenic waste incinerator.

(c) Limited Operation
The theory behind the limited operation for EU 9A was discussed in detail in the NOx BACT for the pathogenic waste incinerator and will not be repeated here. The Department considers limited operation a technically feasible control technology for the pathogenic waste incinerator.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the large dual fuel-fired boiler and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the pathogenic waste incinerator.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for the Pathogenic Waste Incinerator

Natural gas is eliminated as a technically infeasible SO_2 control technology for the pathogenic waste incinerator due to the limited availability.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Pathogenic Waste Incinerator

The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from the pathogenic waste incinerator:

(b) Ultra Low Sulfur Diesel (99% Control)
(c) Good Combustion Practices (Less than 40% Control)
(c) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

UAF BACT Proposal

UAF proposes the following as BACT for SO_2 emissions from the pathogenic waste incinerator:

(a) SO_2 emissions from the operation of EU 9A will be controlled by limiting operation to no more than 109 tons of waste combusted per 12-month rolling period;

(b) SO_2 emissions from the operation of EU 9A shall be controlled by combusting ULSD at all times of operation; and

(c) Compliance will be demonstrated with fuel shipment receipts and/or fuel tests for sulfur content.

Department Evaluation of BACT for SO_2 Emissions from the Pathogenic Waste Incinerator

The Department reviewed UAF's proposal and found that in addition to combusting only ULSD, and limiting operation, good combustion practices is BACT for control of SO_2 emissions from the pathogenic waste incinerator.

Step 5 - Selection of SO_2 BACT for the Pathogenic Waste Incinerator

The Department's finding is that BACT for SO_2 emissions from the pathogenic waste incinerator is as follows:

(a) SO_2 emissions from the operation of EU 9A will be controlled by limiting operation to no more than 109 tons of waste combusted per 12-month rolling period;

(b) SO_2 emissions from the operation of EU 9A shall be controlled by combusting ULSD at all times of operation;

(c) Maintain good combustion practices by following the manufacturer's operational procedures at all times of operation; and

(d) Compliance shall be demonstrated by obtaining fuel shipment receipts and/or fuel tests for sulfur content.

6. BACT DETERMINATION SUMMARY

Table 6-1. NOx BACT Limits

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
3	Mid-Sized Diesel-Fired Boiler	180.9 MMBtu/hr	0.02 lb/MMBtu	Selective Catalytic Reduction Good Combustion Practices
4	Mid-Sized Diesel-Fired Boiler	180.9 MMBtu/hr	Diesel: 0.2 lb/MMBtu NG: 140 lb/MMscf	Limited Operation (EUs 4 and 8 combined 40 tons per rolling 12 month period) Good Combustion Practices
8	Large Diesel-Fired Engine	13,226 hp	1.3 g/hp-hr	Selective Catalytic Reduction Turbocharger and Aftercooler Limit Operation for non-emergency use (100 hours per year) Limited Operation (EUs 4 and 8 combined 40 tons per rolling 12 month period) Good Combustion Practices
9A	Pathogenic Waste Incinerator	83 lb/hr	3.56 lb/ton	Limited Operation (109 tons per rolling 12 month period) Good Combustion Practices
19	Small Diesel-Fired Boiler	6.13 MMBtu/hr	0.015 lb/MMBtu	Limited Operation (19,650 hours per rolling 12 month period combined) Good Combustion Practices
20	Small Diesel-Fired Boiler	6.13 MMBtu/hr	0.015 lb/MMBtu	
21	Small Diesel-Fired Boiler	6.13 MMBtu/hr	0.015 lb/MMBtu	
23	Small Diesel-Fired Engine	235 kW	14.1 g/hp-hr	Good Combustion Practices
26	Small `Diesel-Fired Engine	45 kW	14.1 g/hp-hr	
27	Caterpillar C-15	500 hp	3.2 g/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation (4,380 hours per year)
24	Cummins	51 kW	14.1 g/hp-hr	Limit Operation for non-emergency use (100 hours each per year) Good Combustion Practices
28	Detroit Diesel	120 hp	14.1 g/hp-hr	
29	Cummins	314 hp	0.3 g/hp-hr	
113	Large Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.02 lb/MMBtu	Fabric Filters

Table 6-2. PM-2.5 BACT Limits

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
3	Mid-Sized Diesel-Fired Boiler	180.9 MMBtu/hr	0.012 lb/MMBtu	Good Combustion Practices
4	Mid-Sized Diesel-Fired Boiler	180.9 MMBtu/hr	Diesel: 0.012 lb/MMBtu NG: 0.0075 lb/MMBtu	Limited Operation (EUs 4 and 8 combined 40 tons per rolling 12 month period) Good Combustion Practices
8	Large Diesel-Fired Engine	13,226 hp	0.32 g/hp-hr	Positive Crankcase Ventilation Limited Operation (EUs 4 and 8 combined 40 tons per rolling 12 month period)
9A	Pathogenic Waste Incinerator	83 lb/hr	4.67 lb/ton	Multiple Chambers Limited Operation (109 tons per rolling 12 month period) Good Combustion Practices
19	Small Diesel-Fired Boiler	6.13 MMBtu/hr	7.06 g/MMBtu	Limited Operation (19,650 hours per rolling 12 month period combined) Good Combustion Practices
20	Small Diesel-Fired Boiler	6.13 MMBtu/hr	7.06 g/MMBtu	
21	Small Diesel-Fired Boiler	6.13 MMBtu/hr	7.06 g/MMBtu	
23	Small Diesel-Fired Engine	235 kW	1.0 g/hp-hr	Good Combustion Practices
26	Small `Diesel-Fired Engine	45 kW	1.0 g/hp-hr	
27	Caterpillar C-15	500 hp	0.11 g/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation (4,380 hours per year)
24	Cummins	51 kW	1.0 g/hp-hr	Limit Operation for non-emergency use (100 hours each per year) Good Combustion Practices
28	Detroit Diesel	120 hp	1.0 g/hp-hr	
29	Cummins	314 hp	0.015 g/hp-hr	
105	Material Handling Unit	1,600 acfm	0.003 gr/dscf	Fabric Filters Enclosures Vents
107	Material Handling Unit	1,600 acfm	0.003 gr/dscf	
109	Material Handling Unit	1,600 acfm	0.003 gr/dscf	
110	Material Handling Unit	2,000 acfm	0.003 gr/dscf	
111	Material Handling Unit	N/A	5.5×10^{-5} lb/ton	Enclosure
113	Large Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.006 lb/MMBtu	Fabric Filters
114	Material Handling Unit	5 acfm	0.05 gr/dscf	Fabric Filters Enclosures Vents
128	Material Handling Unit	1,650 acfm	0.003 gr/dscf	
129	Material Handling Unit	1,650 acfm	0.003 gr/dscf	
130	Material Handling Unit	1,650 acfm	0.003 gr/dscf	

Table 6-3. SO_2 BACT Limits

EU ID	Description	Capacity	Proposed BACT Limit	Proposed BACT Control
3	Mid-Sized Diesel-Fired Boiler	180.9 MMBtu/hr	15 ppmv S in Fuel	Ultra-Low Sulfur Diesel
4	Mid-Sized Diesel-Fired Boiler	180.9 MMBtu/hr	Diesel: 15 ppmv S in Fuel NG: 0.60 lb/MMscf	Ultra-Low Sulfur Diesel Limited Operation (EUs 4 and 8 combined 40 tons per rolling 12 month period)
8	Large Diesel-Fired Engine	13,226 hp	15 ppmv S in Fuel	Limited Operation (EUs 4 and 8 combined 40 tons per rolling 12 month period) Good Combustion Practices Ultra-Low Sulfur Diesel
9A	Pathogenic Waste Incinerator	83 lb/hr	15 ppmv S in Fuel	Ultra-Low Sulfur Diesel Limited Operation (109 tons per rolling 12 month period)
19	Small Diesel-Fired Boiler	6.13 MMBtu/hr	15 ppmv S in Fuel	Limited Operation (19,650 hours per rolling 12 month period combined) Ultra-Low Sulfur Diesel
20	Small Diesel-Fired Boiler	6.13 MMBtu/hr	15 ppmv S in Fuel	
21	Small Diesel-Fired Boiler	6.13 MMBtu/hr	15 ppmv S in Fuel	
23	Small Diesel-Fired Engine	235 kW	15 ppmv S in Fuel	Good Combustion Practices
26	Small `Diesel-Fired Engine	45 kW	15 ppmv S in Fuel	
27	Caterpillar C-15	500 hp	15 ppmv S in Fuel	Good Combustion Practices Limited Operation (4,380 hours per year)
24	Cummins	51 kW	15 ppmv S in Fuel	Limit Operation for non-emergency use (100 hours each per year) Good Combustion Practices
28	Detroit Diesel	120 hp	15 ppmv S in Fuel	
29	Cummins	314 hp	15 ppmv S in Fuel	
113	Large Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.10 lb/MMBtu	Dry Sorbent Injection Limestone Injection Low Sulfur Coal

THE STATE of ALASKA
GOVERNOR BILL WALKER

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October 20, 2017

Frances Isgrigg
Director of Environmental Health, Safety & Risk Management
University of Alaska Fairbanks
PO Box 758145
Fairbanks, AK 99775

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum for University of Alaska Fairbanks by December 22, 2017

Dear Ms. Isgirgg:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that the University of Alaska Fairbanks and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to a Serious Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measure (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as the University of Alaska Fairbanks. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analysis is a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an email to Ms. Isgrigg on May 11, 2017 notifying her of the reclassification to Serious and included

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)
[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(4)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.
[3] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

a request for the BACT analysis to be completed by August 8, 2017. The BACT analysis was submitted by email to ADEC on February 8, 2017 from University of Alaska Fairbanks. It included emission units found in Operating Permit AQ0318TVP02 Revision 1 and Minor Permit AQ0318MSS06 Revision 2.

ADEC reviewed the BACT analysis provided for the University of Alaska Fairbanks and is requesting additional information to assist it in making a legally and practicably enforceable BACT determination for the source. ADEC requests a response by December 22, 2017. If ADEC does not receive a response to this information request by this date, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facility's infrastructure and without additional information may select a more stringent BACT for your facility in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public comment along with any pertinent demonstrations and BACM analysis before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes a final BACT determination for the University of Alaska Fairbanks, it must include the determination in the Alaska's Serious SIP that then ultimately requires approval by EPA.[1] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented prior to June 9, 2021 – 4 years after reclassification.[2]

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM) consideration. MSMs will be a required element of the state implementation plan if the State applies for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

ADEC appreciates the cooperation that we've received from the University of Alaska Fairbanks. ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Denise Koch, Director
Division of Air Quality

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[1] https://www.gpo.gov/fdsys/pkg/CFR-2011-title40-vol2/pdf/CFR-2011-title40-vol2-sec51-165.pdf; subpart m(C)(2)a

[2] 40 CFR 51.1010(4)

Enclosures:

October 20, 2017	Request for Additional Information for UAF BACT Analysis
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for UAF

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality
Jim Plosay, ADEC/ Air Quality
Aaron Simpson, ADEC/Air Quality
Brittany Crutchfield, ADEC/Air Quality
Frances Isgrigg/University of Alaska Fairbanks
Tim Hamlin, USEPA Region 10
Zach Hedgpeth, USEPA Region 10

ADEC Request for Additional Information
University of Alaska Fairbanks
BACT Technical Memorandum Review
SLR Report July 2016

October 20, 2017

Please address the following comments by providing the additional information identified by December 22, 2017. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public comment. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public comment period or based upon the new information provided in response to this information request.

This document does not represent a final BACT determination by ADEC. Please contact Aaron Simpson at aaron.simpson@alaska.gov with any questions regarding ADEC's comments.

Draft Comments

1. Equipment Life – Page 123 (Adobe page number) of the analysis[1] states "a standardized ten year return on investment at seven percent interest rate is assumed". This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in interior Alaska experiences more wear and tear than equipment in moderate climates". The 10 year equipment life assumption is based on the harsh climate and evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers. For references on equipment life see the Texas Region 6 SIP findings[2].

2. CFB Boiler: Wet Scrubbing – Clearly explain the basis for excluding wet scrubbing in the BACT analysis.

3. CFB Boiler: SDA and DSI
    a. As part of their Oklahoma Best Available Retrofit Technology (BART) Federal Implementation Plan (FIP) final rule for regional haze[3], US EPA Region 6 found that a reasonable estimate for equipment life is 30 years for SO_2 control technologies, please provide a detailed explanation for the equipment life listed for the SDA and DSI control technologies.
    b. Please provide the documents for the following citations:
        i. "SCI engineering estimates (5 years old) for other SDAs."
        ii. "SCI engineering estimates (5 years old) for other DSI systems"
        iii. "Internal SDA cost study done by SCI in 2010, which indicated 8%."

[1] University of Alaska Fairbanks, Voluntary Best Available Control Technology Analysis for the Serious $PM_{2.5}$ Non-Attainment Area Classification, Prepared by SLR, January 2017
[2] https://www.regulations.gov/document?D=EPA-R06-OAR-2014-0754-0001
[3] 76 FR 81728, December 28, 2011

iv. "…similar internal SCI SDA cost analysis and other vendor (FTEK SCR) quotes."
v. "Internet research bulk price" for hydrated lime.
vi. "Internet research bulk price" for sodium bicarbonate.
vii. "Current Per kW price based on GVEA data."

4. CFB Boiler: SNCR
    a. Please provide the technical justification for the 10-20% emission reduction stated in the email from Babcok and Wilcox for NOx SNCR.
    b. Please provide documentation for the following citations in the BACT analysis:
        i. Indirect capital costs "18% was used in similar SCR BACT analysis. Assume same amount for SNCR."
        ii. "ammonia solution cost from similar BACT analysis - $0.75/gal and specific gravity of 0.9."
        iii. "Current Per kW price based on GVEA data."
    c. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – provide justification for including a 30% contingency factor.

5. CFB Boiler: SCR – Please revise the cost analysis submitted using the EPA updated coast manual chapter pertaining to SCR[4]. Specific comments related to the SCR cost effectiveness analysis include the following:
    a. The recently updated cost manual chapter covering SCR includes information regarding SCR equipment life, and indicates the technology can be expected to last 30 years. Please document why the actual expected equipment life of the control equipment is different from this value.
    b. The BACT analysis as submitted states that the normal exhaust temperature from the CFB boiler is expected to be 1,550-1,650˚F, which is outside of the SCR listed acceptable temperature range. Please provide a technical explanation of why the boiler exhaust temperature is so high. The analysis must also include consideration of high temperature SCR.
    c. Documentation must be provided for the following cited information:
        i. "Cost of startup spares indicated as a percentage of equipment cost per similar project."
        ii. Fab Site Vendor "days based on similar project".
        iii. Onsite Vendor "days based on similar project".
        iv. Indirect capital costs "18% was used in similar SCR BACT analysis for smaller CTs."
        v. "ammonia solution cost from similar BACT analysis - $0.75/gal and specific gravity of 0.9."
        vi. "Current Per kW price based on GVEA data."
        vii. "Replacement labor based on similar project."
        viii. "Labor cost based on similar project."
    d. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – Please include why a 30% contingency factor is accurate.

[4] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

6. EU 3 Mid-Sized Diesel Boiler: PTE – Detailed basis must be provided for the NO_X PTE of 138.8 tpy for EU 3 used in the calculations. If PTE is based on the baseline emission rate used in the FuelTech quote (0.175 lb/MMBtu), the BACT limit proposed for good combustion practices should be 0.175 lb/MMBtu as well.

7. EU 3 Mid-Sized Diesel Boiler: LNB/FGR – This technology is eliminated based on cost effectiveness calculated assuming actual emissions. Please revise the cost analyses to be based on PTE.

8. EU 3 Mid-Sized Diesel Boiler: SCR
    a. Please provide the documentation for following citations in the BACT analysis.
        i. "December 2015 price according to Farmer's Coop Association."
        ii. "Replacement labor based on similar project."
        iii. Transport cost direct to site (SCR catalyst). "Based on similar project."
        iv. Transport cost for spent SCR catalyst. "Based on similar project."
    b. No basis is provided for the SCR freight cost of $20,000.
    c. Initial performance testing cost is included twice.
    d. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual, provide justification for 30% contingency factor.

9. EU 8 Large Diesel Fired Engine: Operational Scenario – Revise the cost analysis to assume operational hours of the unit up to 40 tpy as the emission limit, currently the calculations assume 8760 hours/yr.

10. EU 8 Large Diesel Fired Engine: DPF and SCR – The BACT analysis identifies back pressure as a potential technical challenge of installing a DPF to a large diesel engine such as EU 8, please provide a technical analysis basis for this statement.

11. EU 27 ACEP Generator – The BACT analysis includes evaluations of SCR and DPF as applied individually for control of NO_X and $PM_{2.5}$ respectively, from this emission unit. In addition please evaluate combined SCR/DPF.

12. For the purposes of this BACT analysis the cost analysis for each emissions control for each of EUs 4 and 8 should be based on the assumption that the 40 tpy NOx limit will be consumed by the EU being evaluated. Under the current permitting limit it is possible for one of EUs 4 and 8 to be the sole contributor to the 40 tpy of NOx in any given 12 month rolling period. Additionally, the 10 percent capacity limit for EU 4 was removed with the issuance of Minor Permit No. AQ0316MSS04 on August 4, 2016, and is therefore no longer applicable as limited operation for EU 4. Please revise the PTE and cost analysis for these units.

13. Describe for each emission unit type, what constitutes good combustion practices. Include any work or operational practice that will be implemented and describe how continuous compliance with good combustion practices will be achieved.

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

DIVISION OF AIR QUALITY
Director's Office

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Return Receipt Requested

April 24, 2015

Frances Isgrigg
Director of Environmental Health, Safety & Risk Management
University of Alaska Fairbanks
PO Box 758145
Fairbanks, AK 99775

Subject: Voluntary BACT Analysis for Fairbanks Campus Power Plant

Dear Ms. Isgrigg:

Portions of the Fairbanks North Star Borough are in nonattainment with the 24-hour National Ambient Air Quality Standard for Fine Particulate Matter (PM 2.5). The Alaska Department of Environmental Conservation (ADEC) expects that the Environmental Protection Agency (EPA) will change the nonattainment designation from a Moderate Area to a Serious Area in June 2016. Once EPA designates the area as Serious, an 18-month clock begins for submittal of an implementation plan that includes best available control technologies (BACT) analysis and determination for stationary sources with over 70 tons per year (TPY) potential to emit (PTE) for PM2.5 or its precursors.

ADEC has neither the funding nor the in depth knowledge of your facility's infrastructure to determine the most appropriate BACT for your facility. Without the information or resources necessary to conduct detailed cost analysis and produce supporting documentation, ADEC may select a more stringent BACT for your facility in order to be approvable by EPA. In addition, 18 months is likely not adequate to complete a thorough BACT analysis.

Therefore, ADEC requests that your facility voluntarily begin the BACT analysis. We request that you submit an initial BACT analysis to ADEC by December 2015 and the final BACT analysis by March 2016 to ADEC. ADEC is required to make a BACT determination for every eligible facility within the designated PM2.5 nonattainment area and final BACT determinations are ultimately reviewed by EPA and subject to federal approval as part of the federally required PM2.5 implementation plan.

<u>Background</u>

EPA required that ADEC submit a State Implementation Plan (SIP) because portions of the Fairbanks North Star Borough (FSNB) are in nonattainment with the health based 24-hour National Ambient Air Quality Standard for PM2.5. ADEC submitted an initial, Moderate Area PM2.5 SIP for FNSB to EPA on December 31, 2014.

Unfortunately, this Moderate Area SIP was developed as an impracticable SIP because modeling was unable to demonstrate that attainment with the health standard was possible by December 30, 2015. Preliminary air monitoring results also indicate that FNSB will not demonstrate attainment in 2015. Attainment is calculated on a rolling three year average of the highest 98th percentile concentration at each monitor. When those monitoring results become final in May 2016 and an official three year design value is calculated, the FNSB non-attainment area will remain over the 24-hr PM 2.5 standard of 35 $\mu g/m^3$. The final determination of this design value will result in the FNSB non-attainment area being reclassified from a Moderate Area to a Serious Area[1] (40 CRF Parts 50, 51 and 93). This reclassification will happen by operation of law as outlined in Clean Air Act Sections 188 and 189. It is anticipated that the formal designation to Serious Area will occur in June 2016.

A Serious Area designation will result in several new, more stringent requirements, one of which is that all source categories in the nonattainment area that meet the BACT threshold of 70 TPY PTE for $PM_{2.5}$ and its precursor pollutants (NOx, SO2, VOC, NH3) must be analyzed for Best Available Control Measures (BACM). As part of BACM, a Best Available Control Technologies (BACT) analysis will be required. The Serious Area BACT trigger requires the same approach as a PSD/NSR BACT project. A Serious non-attainment area BACT limit is set using a top-down analysis on a case-by-case basis taking into account energy, environmental and economic impacts, and costs. The analysis must include all emission units at the source.

The timelines for completion of the BACT analysis, subsequent BACT determination, and the submittal of the Serious Area SIP are outlined in the preamble of the Particulate Matter 10 (PM10) rule and reconfirmed in the newly proposed $PM_{2.5}$ Implementation Rule[2]. Both rules require a completed SIP 18 months after designation to Serious. This 18 month time period does not allow enough time to thoroughly evaluate BACT, update the emission inventory, complete the modeling and allow for development and processing for a Serious Area SIP.

ADEC believes that it is best for facilities to complete the BACT analysis for their own facilities. ADEC does not have the funding to develop the analysis nor the in depth knowledge of each sources' infrastructure. ADEC would therefore base the cost analysis on the installation of control equipment without being able to factor in all the costs associated with retrofitting existing equipment. Without the detailed cost analysis and supporting documentation to support less stringent BACT options, it is doubtful that the BACT portions of the Serious SIP will be approvable without using the most stringent measures.

By requesting an early BACT analysis for facilities before the official Serious Area designation, it will help ADEC meet the following timelines and ultimately submit a Serious Area SIP to EPA by the

[1] 40 CFR Parts 50,51 and 93 http://www.epa.gov/airquality/particlepollution/actions.html

[2] http://www.epa.gov/airquality/particlepollution/actions.html

required due date. Early analysis also has the potential to increase flexibility for each Stationary Source under the rules.

- Serious Area SIP inventory development starts: January, 2015
- BACT kick off meeting: March 5, 2015
- Submit initial BACT results to ADEC: December, 2015
- Submit complete/ final BACT analysis to ADEC: March, 2016
- Serious Area SIP modeling by ADEC starts: March, 2016
- Serious Area designation by EPA (Expected): June, 2016
- Serious Area SIP draft: December, 2016
- Serious Area SIP public notice period: February, 2017
- Serious Area SIP submitted by ADEC to EPA: December, 2017

Meeting the BACT analysis requirements is a major component of a Serious SIP. This is a challenging issue. It is important that ADEC accurately reflect the contributions of industrial sources to the air pollution problem and the potential improvements available within this emission sector along with the other emission sources in the community.

ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Denise Koch, Director
Division of Air Quality

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
John Kuterbach, ADEC/ Air Quality
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality

University of Alaska Fairbanks – Serious PM-2.5 NA BACT Analysis
BACT Analysis Review Comments
Report dated January 2017 – SLR

Zach Hedgpeth, PE
EPA Region 10 – Seattle
November 2, 2017

1. Equipment Life – Page 123 of the analysis[1] states "a standardized ten year return on investment at seven percent interest rate is assumed". This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in interior Alaska experiences more wear and tear than equipment in moderate climates". The analysis includes no further information to support the assumption of a ten year equipment life, nor the underlying assertion regarding wear and tear. The analysis must use a reasonable estimate of the actual life of the control equipment for each control technology, based on the best evidence available. In order to use an equipment life that is shortened based on the harsh climate, evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers.
2. CFB Boiler: Additional SO_2 Control Technologies – The BACT analysis mentions wet scrubbing technologies, but does not clearly explain the basis for excluding these technologies (such as limestone slurry forced oxidation) from consideration within the analysis. Since wet scrubbing would be expected to represent the highest SO_2 removal efficiency, this technology must be fully evaluated within the BACT analysis. Similarly, the analysis does not evaluate dry flue gas desulfurization or dry scrubbing. This enhanced dry SO_2 control technology can achieve higher removal efficiencies than dry sorbent injection, and must also be evaluated thoroughly within the BACT analysis. The BACT analysis must include rigorous site-specific evaluation of the technical feasibility and cost effectiveness of these technologies.
3. CFB Boiler: SDA and DSI
    a. As part of their Oklahoma Best Available Retrofit Technology (BART) Federal Implementation Plan (FIP) final rule for regional haze[2], EPA Region 6 conducted significant research into the actual expected lifetime of SO_2 control technologies, including wet, semi-dry, and dry scrubbing. Region 6 found that 30 years is a reasonable estimate of actual expected equipment life for these control technologies. The analysis for SDA and DSI therefore should use 30 years unless documented evidence is provided establishing that the actual expected equipment life of the control equipment is different from this value.
    b. The SDA and DSI cost analyses submitted with this analysis cite the following documents as the basis for costs and other information relied upon in the analysis, however, these documents have not been provided. These documents must be provided in order to rely upon the cited information in the analysis:
        i. "SCI engineering estimates (5 years old) for other SDAs."
        ii. "SCI engineering estimates (5 years old) for other DSI systems"
        iii. "Internal SDA cost study done by SCI in 2010, which indicated 8%."
        iv. "…similar internal SCI SDA cost analysis and other vendor (FTEK SCR) quotes."
        v. "Internet research bulk price" for hydrated lime.

[1] University of Alaska Fairbanks, Voluntary Best Available Control Technology Analysis for the Serious $PM_{2.5}$ Non-Attainment Area Classification, Prepared by SLR, January 2017
[2] 76 FR 81728, December 28, 2011

vi. "Internet research bulk price" for sodium bicarbonate.
vii. "Current Per kW price based on GVEA data."

4. CFB Boiler: SNCR
    a. Within an email included in Appendix B, Babcock & Wilcox states only minimal NO_X reduction of around 10-20% would be expected from SNCR. In order to base the cost analysis on this minimal emission reduction, detailed technical justification must be submitted providing a rigorous basis for why SNCR can only achieve this smaller than average/expected emission reduction for this emission unit.
    b. The SNCR cost analysis cites the following documents and information as the basis for costs and other information relied upon in the analysis, however, documentation for these values and information has not been provided. Documentation must be provided in order to rely upon the cited information in the analysis:
        i. Indirect capital costs "18% was used in similar SCR BACT analysis. Assume same amount for SNCR."
        ii. "ammonia solution cost from similar BACT analysis - $0.75/gal and specific gravity of 0.9."
        iii. "Current Per kW price based on GVEA data."
    c. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – it is not appropriate to include a 30% contingency factor based on this accuracy range.
5. CFB Boiler: SCR – The EPA has recently updated the cost manual chapter pertaining to SCR, and developed a cost spreadsheet to be used for evaluation of this technology for cost effectiveness[3]. The cost analysis submitted as part of this BACT analysis[4] does not use the EPA cost spreadsheet. Specific comments related to the SCR cost effectiveness analysis include the following:
    a. The recently updated cost manual chapter covering SCR includes information regarding SCR equipment life, and indicates the technology can be expected to last 30 years. The analysis should use 30 years as the equipment life for SCR unless documented evidence is provided establishing that the actual expected equipment life of the control equipment is different from this value.
    b. The BACT analysis as submitted states that the normal exhaust temperature from the CFB boiler is expected to be 1,550-1,650˚F. This factor is listed as a technical feasibility issue for SCR as a potential control technology since the temperature range for SCR is listed as 500-800˚F. Please provide a technical explanation of why the boiler exhaust temperature is so high, and why additional heat recovery has not been included in the design of the new power plant. The analysis must also include thorough analysis of high temperature SCR with respect to technical feasibility and cost effectiveness.
    c. The SCR cost analysis cites the following documents and information as the basis for costs and other information relied upon in the analysis, however, documentation for these values and information has not been provided. Documentation must be provided in order to rely upon the cited information in the analysis:
        i. "Cost of startup spares indicated as a percentage of equipment cost per similar project."
        ii. Fab Site Vendor "days based on similar project".
        iii. Onsite Vendor "days based on similar project".

[3] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

[4] "UAF BACT NOx Tables 3-X.xlsx"

iv. Indirect capital costs "18% was used in similar SCR BACT analysis for smaller CTs."
v. "ammonia solution cost from similar BACT analysis - $0.75/gal and specific gravity of 0.9."
vi. "Current Per kW price based on GVEA data."
vii. "Replacement labor based on similar project."
viii. "Labor cost based on similar project."

d. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – it is not appropriate to include a 30% contingency factor based on this accuracy range.

6. EU 3 Mid-Sized Diesel Boiler: PTE – Detailed basis must be provided for the NO_X PTE of 138.8 tpy for EU 3 used in the calculations. Note that page 19 of the Title V statement of basis[5] states that emissions from this boiler "in terms of ton/yr were never and will not be limited". Based on the proposed BACT limit of 0.2 lb/MMBtu for good combustion practices, it appears the PTE should, at a minimum, reflect full load operation at this emission rate for 8,760 hours/year (about 158 tpy). If PTE is based on the baseline emission rate used in the FuelTech quote (0.175 lb/MMBtu), the BACT limit proposed for good combustion practices should be 0.175 lb/MMBtu as well.
7. EU 3 Mid-Sized Diesel Boiler: LNB/FGR
    a. This technology is eliminated based on cost effectiveness calculated assuming actual emissions. All cost analyses and BACT determinations must be based on PTE.
    b. On page 39, the BACT analysis describes this control option as "installation of a new burner on the boiler that is already equipped with a LNB and FGR". The analysis must clarify the current status of the boiler with respect to LNB and FGR technology. If the boiler is already equipped with FGR, detailed technical justification must be provided regarding why the fan(s) and/or ducting must be replaced.
8. EU 3 Mid-Sized Diesel Boiler: SCR
    a. The SCR cost analysis cites the following documents and information as the basis for costs and other information relied upon in the analysis, however, documentation for these values and information has not been provided. Documentation must be provided in order to rely upon the cited information in the analysis:
        i. "December 2015 price according to Farmer's Coop Association."
        ii. "Replacement labor based on similar project."
        iii. Transport cost direct to site (SCR catalyst). "Based on similar project."
        iv. Transport cost for spent SCR catalyst. "Based on similar project."
    b. No basis is provided for the SCR freight cost of $20,000.
    c. Initial performance testing cost is included twice.
    d. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – it is not appropriate to include a 30% contingency factor based on this accuracy range.
9. EU 3 Mid-Sized Diesel Boiler: ULSD – The ULSD cost analysis is based on "review of UAF's fuel costs from FY 2011 through 2016. Average of the FY 2014 through 2016 is used, which is 28 cents per gallon more to use ULSD." The documents forming the basis for this information must be submitted in order to rely on this information for purposes of the analysis.
10. EU 8 Large Diesel Fired Engine: Operational Scenario – The NO_X BACT analysis for this unit applies the facility-requested 40 ton per year emission limit, and bases the analysis on an

[5] ADEC Permit No. AQ0316TVP02, Significant Revision 1: June 22, 2012, Statement of Basis

assumed NO_X reduction of only 36 tons (90% reduction from 40 tpy). However, the analysis assumes that the unit operates 8,760 hours/year when calculating the annual O&M costs (i.e., see aqueous ammonia cost). The assumptions underlying the cost analysis are therefore inconsistent. The cost effectiveness analysis must be revised to be consistent based on the assumed operational scenario for the unit. For example, if the unit is assumed to operate uncontrolled for NO_X up to the 40 ton/year limit, the corresponding costs associated with only those limited number of hours may be included. This applies to all annual operating & maintenance costs, including catalyst life.

11. EU 8 Large Diesel Fired Engine: SCR – Please provide detailed information regarding the visible emissions described in the BACT analysis which were observed during operation of the SCR currently installed on the large diesel engine. See page 19.
12. EU 8 Large Diesel Fired Engine: DPF and SCR – The BACT analysis identifies back pressure as a potential technical challenge of installing a DPF to a large diesel engine such as EU 8, but provides no technical analysis or other quantitative or analytical basis for this argument. Further, the BACT analysis determines that an appropriate DPF "likely does not exist" without citing any information from established DPF equipment suppliers. The BACT analysis cites only a single local Fairbanks engine company, whose employee states that the company has "never supplied a DPF with a new engine or for after market use". The information provided forms insufficient basis to reject DPF as technically infeasible and/or not cost effective. The analysis must provide detailed technical analysis of the back pressure issue by an engineering firm or control equipment supplier with the necessary expertise regarding the control technology. In order to establish the availability of a suitable DPF, the analysis must include information regarding these topics from established DPF control equipment suppliers. The availability of this control technology is not limited to DPF equipment currently available "off the shelf". UAF must explore whether manufacture of an appropriate DPF for this emission unit is technically feasible, and conduct an emission unit specific cost analysis following the EPA Cost Manual.
13. EU 27 ACEP Generator – The BACT analysis includes evaluations of SCR and DPF as applied individually for control of NO_X and $PM_{2.5}$ respectively, from this emission unit, however a combination SCR/DPF was not evaluated. The analysis must be revised to include a cost effectiveness analysis for this combined control technology.

UNIVERSITY OF ALASKA FAIRBANKS
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December 21, 2017

Denise Koch, Director
Alaska Department of Environmental Conservation
Division of Air Quality
410 Willoughby Avenue, Suite 303
Juneau, Alaska 99811-1800

Subject: ADEC Request for additional information for the Best Available Control Technology for University of Alaska Fairbanks

Dear Ms. Koch:

The University of Alaska Fairbanks (UAF) received a request for additional information regarding the Best Available Control Technology (BACT) analysis from the Alaska Department of Environmental Conservation (ADEC) on October 20, 2017. This request included a set of 13 comments. ADEC provided a second set of comments and information requests from the US Environmental Protection Agency (EPA) Region 10 on November 6, 2017.

UAF understands that ADEC expects responses to both sets of comments. EPA Region 10 comments 1 through 8 are similar or identical to ADEC comments 1 through 8. EPA Region 10 comments 9 and 11 address issues that were not mentioned in the ADEC comments. Comment 10 from EPA Region 10 is a similar question to comment 9 from ADEC, and comments 12 and 13 from EPA Region 10 are comparable to ADEC comments 10 and 11. Comments 12 and 13 from ADEC were not addressed in the EPA Region 10 comments.

UAF is providing responses to each comment from EPA Region 10, and to ADEC comments 12 and 13, thus addressing each comment from both agencies. Each comment is repeated verbatim in the attachment, followed by the UAF response.

If you have any questions or require additional information regarding this response, please feel free to contact me using the information below my signature.

The University of Alaska Fairbanks is an AA/EO employer and educational institution and prohibits illegal discrimination against any individual. Learn more about UA's notice of nondiscrimination at www.alaska.edu/nondiscrimination

Sincerely,



Russ Steiger
Environmental Compliance Officer
University of Alaska Fairbanks
Office of Environmental, Health, Safety, and Risk Management
Office: (907) 474-5812
Mobile: (716) 534-1511
Email: rhsteiger@alaska.edu

Enclosures:

Attachment 1: UAF Response to EPA Region 10 and ADEC Comments on BACT Analysis

cc (email) Deanna Huff/ADEC
Cindy Heil/ADEC
Aaron Simpson/ADEC
Denise Koch/ADEC
Zach Hodgpeth/EPA Region 10
Frances Isgrigg/UAF EHSRM

ATTACHMENT 1
UAF RESPONSE TO EPA REGION 10 and ADEC COMMENTS ON BACT ANALYSIS

EPA Region 10 Comments

1. Equipment Life – Page 123 of the analysis states "a standardized ten year return on investment at seven percent interest rate is assumed". This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in interior Alaska experiences more wear and tear than equipment in moderate climates". The analysis includes no further information to support the assumption of a ten-year equipment life, nor the underlying assertion regarding wear and tear. The analysis must use a reasonable estimate of the actual life of the control equipment for each control technology, based on the best evidence available. In order to use an equipment life that is shortened based on the harsh climate, evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers.

UAF Response to Comment 1:
Consistent with established ADEC practice and previously approved PSD permitting BACT analyses, a 20-year equipment life was used in the calculation of the capital recovery factor for the UAF BACT analysis. This 10-year equipment life timeframe is appropriate for equipment operated in the harsh Alaska climate. Two recent permits with BACT analyses based on a 10-year life are Permit No. AQ0233CPT04 (see footnote to Table B-4 of the Technical Analysis Report) and Permit No. AQ0083CPT06 (see page 24 of Technical Analysis Report).

The EPA Air Pollution Control Cost Manual (sixth edition, EPA/452/B-02-001, Control Cost Manual) uses equipment lifetimes between 5 and 30 years. Ten, 15, and 20-year lifespans are frequently used in the manual.

The updated selective catalytic reduction [SCR] section of the Control Cost Manual states "broadly speaking, a representative value of the equipment life for SCR at power plants can be considered as 30 years. For other sources, the equipment life can be between 20 and 30 years. The remaining life of the boiler may also be a determining factor for the system lifetime." The updated selective non-catalytic reduction [SNCR] section of the Control Cost Manual uses a 20-year lifespan in the example analysis, based on three petroleum refinery who estimated SNCR life at between 15 and 25 years.

Draft comment 1 from ADEC cited a proposed federal rulemaking addressing a regional haze determination from EPA Region 6. The preamble to the proposed rule includes a discussion of equipment life for sulfur dioxide (SO_2) scrubbers. The preamble states that a prior Oklahoma Federal Implementation Plan [FIP] used a lifetime of 30 years to determine costs for SO_2 scrubbers. Expanding the use of the Oklahoma FIP 30-year equipment life to the UAF equipment is not appropriate because the technically feasible emission controls identified for the UAF emissions units (with the exception of EU 113) do not include SO_2 scrubbers. Additionally,

emission control equipment that may be suitable for use in Oklahoma may not be suitable for use in Interior Alaska, for obvious reasons.

*A 30-year equipment life for control equipment on EU 113 is consistent with EPA long-standing guidance regarding equipment life determinations. The 1990 New Source Review Workshop Manual for Prevention of Significant Deterioration and Nonattainment Area Permitting states on page B-16 of Appendix B that "The economic life of a control system typically varies between 10 to 20 years and longer **and** should be determined consistent with data from EPA cost support documents and the IRS Class Life Asset Depreciation Range System" (emphasis added). EU 113 will be a co-generation boiler that will produce steam for campus heat, as well as steam for the generation of electricity. Table B-1 of IRS Publication 946 (2016) provides a class life, or a tax cost recovery period, of 22 years for assets associated with Industrial Steam and Electric Generation and/or Distribution Systems (see Asset Class 00.4). As a result, a 30-year equipment life is not consistent with the EPA policy that the economic life of a control system should also be consistent with the IRS Class Life Asset Depreciation Range System.*

2. **CFB Boiler: Additional SO_2 Control Technologies – The BACT analysis mentions wet scrubbing technologies, but does not clearly explain the basis for excluding these technologies (such as limestone slurry forced oxidation) from consideration within the analysis. Since wet scrubbing would be expected to represent the highest SO_2 removal efficiency, this technology must be fully evaluated within the BACT analysis. Similarly, the analysis does not evaluate dry flue gas desulfurization or dry scrubbing. This enhanced dry SO_2 control technology can achieve higher removal efficiencies than dry sorbent injection, and must also be evaluated thoroughly within the BACT analysis. The BACT analysis must include rigorous site-specific evaluation of the technical feasibility and cost effectiveness of these technologies.**

GRP Response to Comment 2:
The circulating fluidized bed (CFB) boiler design includes integrated dry scrubbing control technology. The CFB boiler incorporates dry scrubbing technology by way of the limestone injection system that is inherent to the CFB design. Wet scrubbing is typically not used in connection with CFB technology. The RACT/BACT/LAER Clearinghouse (RBLC) database does not list any applications of wet scrubbers used with CFB boilers. Wet scrubbing is essentially a more expensive version of dry scrubbing, and therefore is only utilized for the biggest, most challenging scrubbing applications. Because dry scrubbing technology has advanced to achieving approximately the same control efficiency as wet scrubbing (90 percent or greater), the cost effectiveness for wet scrubbing would only be higher due to the higher capital cost.

Please refer to the email from David Nowogrocki at Babcock and Wilcox (B&W) to John Sakes on February 2, 2016 in Appendix E of the BACT analysis report. B&W indicates that dry sorbent injection (DSI) and semi-dry scrubbing are feasible post-combustion SO_2 controls for the boiler. The DSI control system evaluated in the BACT analysis is in addition to the dry scrubbing that occurs within the boiler bed.

3. CFB Boiler: SDA and DSI
   a. As part of their Oklahoma Best Available Retrofit Technology (BART) Federal Implementation Plan (FIP) final rule for regional haze, EPA Region 6 conducted significant research into the actual expected lifetime of SO_2 control technologies, including wet, semi-dry, and dry scrubbing. Region 6 found that 30 years is a reasonable estimate of actual expected equipment life for these control technologies. The analysis for SDA and DSI therefore should use 30 years unless documented evidence is provided establishing that the actual expected equipment life of the control equipment is different from this value.

UAF response to Comment 3a:
The Control Cost Manual does not indicate the use of a 30-year equipment life for any SO_2 emission control systems. The Control Cost Manual, Section 5.2, Chapter 1, paragraph 1.5.2, provides a 15-year equipment life for a wet scrubber, and cites Section 1 of the manual regarding capital recovery costs.

The EPA Region 6 use of a 30-year life for SO2 scrubbers is not necessarily consistent with the EPA Cost Control Manual or Appendix B of the 1990 New Source Review Workshop Manual, and is not a mandate for all future BACT analyses to use 30-year lifespans for SO_2 emission control systems.

UAF does not agree that a 30-year equipment life is appropriate, as discussed in the response to Comment 1 above. As a courtesy, UAF did re-calculate the cost analysis with a basis of a 25-year equipment life. For a spray dryer absorber (SDA), the cost effectiveness would be $11,598 per ton of SO_2 removed and for dry sorbent injection (DSI), the cost effectiveness would be $8,186 per ton of SO_2 avoided.

   b. The SDA and DSI cost analyses submitted with this analysis cite the following documents as the basis for costs and other information relied upon in the analysis; however, these documents have not been provided. These documents must be provided in order to rely upon the cited information in the analysis:
      i. "SCI engineering estimates (5 years old) for other SDAs."

UAF response to Comment 3b(i):
These estimates were based on a Boiler MACT compliance feasibility study prepared by SCI for a confidential client. This documentation is client confidential and cannot be provided to the agency.

      ii. "SCI engineering estimates (5 years old) for other DSI systems."

UAF response to Comment 3b(ii):
These estimates were based on a Boiler MACT compliance feasibility study prepared by SCI for a confidential client. This documentation is client confidential and cannot be provided to the agency.

iii. **"Internal SDA cost study done by SCI in 2010, which indicated 8%."**

UAF response to Comment 3b(iii):
These estimates were based on a Boiler MACT compliance feasibility study prepared by SCI for a confidential client. This documentation is client confidential and cannot be provided to the agency.

iv. **"...similar internal SCI SDA cost analysis and other vendor (FTEK SCR) quotes."**

UAF response to Comment 3b(iv):
These estimates were based on a Boiler MACT compliance feasibility study prepared by SCI for a confidential client. This documentation is client confidential and cannot be provided to the agency. The FTEK SCR quote was provided in Appendix B of the BACT analysis report.

v. **"Internet research bulk price" for hydrated lime.**

UAF response to Comment 3b(v):
The cost of $560/ton for hydrated lime was conservatively high. Based on more recent internet research, the price for bulk hydrated lime is estimated to be approximately $150/ton (lime plant value) per this website: https://minerals.usgs.gov/minerals/pubs/commodity/lime/mcs-2017-lime.pdf. Delivery to Fairbanks, Alaska would incur a higher, unknown cost. Using $150/ton in the analysis is therefore conservatively low. This adjustment results in minimal reduction to the cost effectiveness value for the use of SDA control.

vi. **"Internet research bulk price" for sodium bicarbonate.**

UAF Response to Comment 3b(vi):
Sodium bicarbonate price rates are available at http://www.solvaychemicals.com/bge-sodium-carbonate-online.html. The prices provided on this website do not include shipping costs. The cost of $700/ton presented in the analysis is likely conservatively low when accounting for delivery to Fairbanks Alaska.

vii. **"Current Per kW price based on GVEA data."**

UAF Response to Comment 3b(vii):
The electrical utility provider in Fairbanks, Golden Valley Electric Association (GVEA) currently charges $0.209 per kilowatt-hour. The UAF BACT analysis cites $0.18 per kilowatt-hour because that particular value was prepared in 2010. Current GVEA rates are available at http://www.gvea.com/rates/rates

- CFB Boiler: SNCR
  - a. Within an email included in Appendix B, Babcock & Wilcox states only minimal NO_x reduction of around 10-20% would be expected from SNCR. In order to base the cost analysis on this minimal emission reduction, detailed technical justification must be submitted providing a rigorous basis for why SNCR can only achieve this smaller than average/expected emission reduction for this emission unit.

    UAF Response to Comment 6a:
    Babcock and Wilcox (B&W) is the boiler manufacturer for EU 11.1 and is the source of technical expertise about this boiler. The SNCR emission reduction efficiencies discussed in the Control Cost Manual can be quite low, particularly for coal-fired boilers with low nitrogen oxides (NO_x) concentrations at the inlet to the emission control system. (See Figures 1.1a and 1.1c in Chapter 1, Section 1 in the updated SNCR chapter of the Control Cost Manual.) B&W has significant experience providing NO_x control systems for utility boilers such as EU 11.1. Given the B&W involvement in the design of the UAF CFB boiler, depth of knowledge of boiler exhaust characteristics and extensive knowledge on reductions that can be achieved from an SNCR control system, B&W has the expertise to make this determination. UAF accepts the B&W expert analysis of control technology for the CFB boiler and as is not providing additional justification for the SNCR NO_x emission reduction efficiencies.

  - b. The SNCR cost analysis cites the following documents and information as the basis for costs and other information relied upon in the analysis, however, documentation for these values and information has not been provided. Documentation must be provided in order to rely upon the cited information in the analysis:
    - i. Indirect capital costs "18% was used in similar SCR BACT analysis. Assume same amount for SNCR."

      UAF Response to Comment 6b(i):
      The indirect capital costs are calculated using 18 percent of the total direct cost (purchased equipment and material costs and direct installation costs). The BACT analysis for the SCR systems on the combustion turbines at the Exxon Mobil Point Thomson Production Facility used the same ratio. Please see Page 23 of the Technical Analysis Report (TAR) to Permit No. AQ1201CPT01 Limitation with that ADEC-approved analysis. UAF believes that 18 percent is an appropriate ratio for the EU 11.1 SNCR cost analysis.

    - ii. "ammonia solution cost from similar BACT analysis - $0.75/gal and specific gravity of 0.9."

      UAF Response to Comment 6b(ii):
      Several different references indicate that ammonia solution has a specific gravity of approximately 0.9. The BACT analysis for the SCR systems on the combustion turbines at the Exxon Mobil Point Thomson Production Facility used an ammonia

solution cost of $0.75 per gallon. Please see Page 23 of the TAR to Permit No. AQ1201CPT01. Consistent with that ADEC-approved analysis, UAF believes that a cost of $0.75 per gallon is representative of ammonia costs for this analysis.

UAF notes that if any aqueous ammonia were to be used, the concentration of that solution would be less than 20 percent. The freezing point of 19 percent aqueous ammonia is -28 degrees Fahrenheit. Ambient temperatures during winter in Interior Alaska routinely drop below -30 degrees Fahrenheit, so considerations for heat tracing, circulation, as well as shipment of the solution to Fairbanks (with the inherent risk in supply disruption) are all likely to result in higher costs.

iii. **"Current Per kW price based on GVEA data."**

UAF Response to Comment 4(iii):
The electrical utility provider in Fairbanks, Golden Valley Electric Association (GVEA) currently charges $0.204 per kilowatt-hour. The UAF BACT analysis cites $0.18 per kilowatt-hour because that particular calculation was prepared in 2014. Current GVEA rates are available at http://www.gvea.com/rates/rates.

c. **The budgetary nature of the costs provided by Fuel Tech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – it is not appropriate to include a 30% contingency factor based on this accuracy range.**

UAF Response to Comment 4c:
The capital costs for the SNCR system on the CFB boiler were provided by Babcock & Wilcox (B&W). The B&W estimate did not include any contingency costs. Because preparing a BACT analysis requires obtaining vendor pricing information without knowing the exact final emission limits, the vendor could not be provided with a precise emissions target. The vendor therefore must rely upon their general experience of what percent reduction could be achieved by an SNCR system. Applying a contingency factor in the cost effectiveness evaluation is both practical and appropriate. Use of a contingency factor for costs associated with control device retrofits is also consistent with a Boiler MACT compliance feasibility study prepared by SCI for a confidential client with six coal-fired boilers. Please see also the UAF response to Comment 4b(ii) above.

A contingency cost of 30 percent was applied to equipment and material costs, direct installation costs, and engineering and procurement costs in the BACT analysis for the SCR systems on the combustion turbines at the Exxon Mobil Joint Thermoelectric Production Facility. Please see Page 23 of the Technical Analysis Report (TAR) to Permit No. AQ1201CPT01 Consistent with that ADEC-approved analysis, UAF believes that 30 percent is an appropriate value for the $11.13 SNCR cost analysis.

5. <u>CFB Boiler: SCR</u> – **The EPA has recently updated the cost manual chapter pertaining to SCR.**

and developed a cost spreadsheet to be used for evaluation of this technology for cost effectiveness. The cost analysis submitted as part of this BACT analysis does not use the EPA cost spreadsheet. Specific comments related to the SCR cost effectiveness analysis include the following:

a. The recently updated cost manual chapter covering SCR includes information regarding SCR equipment life, and indicates the technology can be expected to last 30 years. The analysis should use 30 years as the equipment life for SCR unless documented evidence is provided establishing that the actual expected equipment life of the control equipment is different from this value.

UAF Response to Comment 3a:
The updated SCR section of the Control Cost Manual states "broadly speaking, a representative value of the equipment life for SCR at power plants can be considered as 30 years. For other sources, the equipment life can be between 20 and 30 years. The remaining life of the boiler may also be a determining factor for the system lifetime."

UAF does not agree that a 30-year equipment life is appropriate, as discussed in the response to Comment 1 above. As a courtesy, UAF did re-calculate the cost analysis with a basis of a 20 year equipment life. For selective catalytic reduction (SCR), the cost effectiveness would be $22,252 per ton of NO_x emissions avoided.

b. The BACT analysis as submitted states that the normal exhaust temperature from the CFB boiler is expected to be 1,550-1,650°F. This factor is listed as a technical feasibility issue for SCR as a potential control technology since the temperature range for SCR is listed as 500-800°F. Please provide a technical explanation of why the boiler exhaust temperature is so high, and why additional heat recovery has not been included in the design of the new power plant. The analysis must also include thorough analysis of high temperature SCR with respect to technical feasibility and cost effectiveness.

UAF Response to Comment 3b:
The BACT analysis report correctly states on page 11 that the boiler combustion temperature is expected to range between 1,550 and 1,650 °F. UAF acknowledges that the description of the exhaust gas temperature provided on page 12 of the BACT analysis is not accurate.

Sargent Consultants contacted Babcock and Wilcox (B&W) to seek clarification of exhaust gas characteristics. B&W indicated that the predicted flue gas temperatures at maximum continuous rate (MCR) conditions for the CFB boiler as listed on the performance summary sheet for the boiler are as follows:

- *Exit of superheat bank* 774°F
- *Inlet of economizer* 774°F
- *Exit of economizer* 662°F
- *Exit of air preheater* 325°F

The ideal gas temperature for NO_x reduction ranges for SCR is from 700 to 750°F. (Steam - Its Generation and Use, Babcock & Wilcox, 42nd Edition, 2015). At utility boilers, the typical SCR system would be placed at the economizer outlet, preceding the air heater. As shown in the above temperature profile, the exit temperature at the economizer outlet is well below the ideal range. The exhaust flow coming out of the boiler is closer to the documented range, however design modifications would be needed to fit the SCR system into this arrangement and would involve a redesign of structure of the highrise building to accommodate the installation of the SCR above the highrise. Given the seismic design criteria of the site, this would be a challenging and expensive undertaking. These unique characteristics only serve to drive up capital costs and consequently the cost effectiveness value of the SCR control system.

i. **The SCR cost analyses cites the following documents and information as the bases for costs and other information relied upon in the analysis, however, documentation for these values and information has not been provided. Documentation must be provided in order to rely upon the cited information in the analysis:**

   i. **"Cost of startup spares indicated as a percentage of equipment cost per similar project."**

   UAF Response to Comment 5c(i):
   The cost of startup spares was estimated as a percentage of equipment cost in a similar project. The UAF consultant indicates that the project was prepared for a confidential client. UAF believes that the cost for startup spare equipment estimated at 0.50 percent of total equipment costs is reasonable for purposes of this analysis.

   ii. **Fab Site Vendor "days based on similar project".**

   UAF Response to Comment 5c(ii):
   The fabrication site vendor representative fees were assumed to be comparable to those fees from a similar project. The UAF consultant indicates that the project was prepared for a confidential client. UAF believes that these vendor fees are reasonable for purposes of this analysis.

   iii. **Onsite Vendor "days based on similar project".**

   UAF Response to Comment 5c(iii):
   The onsite vendor representative fees were assumed to be comparable to those fees from a similar project. The UAF consultant indicates that the project was prepared for a confidential client. UAF believes that these vendor fees are reasonable for purposes of this analysis.

   iv. **Indirect capital costs "18% was used in similar SCR BACT analysis for**

smaller CTs."

UAF Response to Comment 5c(v).
The indirect capital costs are calculated using 10 percent of the total direct cost (purchased equipment and material costs and direct installation costs). The BACT analysis for the SCR systems on the combustion turbines at the Exxon Mobil Point Thomson Production Facility used the same ratio. Please see Page 23 of the Technical Analysis Report (TAR) to Permit No. AQ1201CPT01.Consistent with that ADEC-approved analysis, UAF believes that 10 percent is an appropriate ratio for the FG 113 SNCR cost analysis.

iv. **"ammonia solution cost from similar BACT analysis - $0.75/gal and specific gravity of 0.9"**

UAF Response to Comment 5c(iv).
Several different references indicate that ammonia solution has a specific gravity of approximately 0.9. The BACT analysis for the SCR systems on the combustion turbines at the Exxon Mobil Point Thomson Production Facility used an ammonia solution cost of $0.75 per gallon. Please see Page 23 of the TAR to Permit No. AQ1201CPT01. Consistent with that ADEC-approved analysis, UAF believes that a cost of $0.75 per gallon is representative of ammonia costs for this analysis.

UAF notes that if any aqueous ammonia were to be used, the concentration of that solution would be less than 20 percent. The freezing point of 19 percent aqueous ammonia is -30 degrees Fahrenheit. Ambient temperatures during winter in interior Alaska routinely drop below -30 degrees Fahrenheit, so considerations for heat tracing, circulation, or self-ist shipment of the solution to Fairbanks (with the inherent risk in supply disruption) are all likely to result in higher costs.

vi. **"Current Per kW price based on GVEA data."**

UAF Response to Comment 5c(vi).
The electrical utility provider to Fairbanks, Golden Valley Electric Association (GVEA) currently charges $0.209 per kilowatt-hour. The UAF BACT analysis cites $0.18 per kilowatt-hour because that particular calculation was prepared in 2016. Current GVEA rates are available at http://www.gvea.com/rates/rates.

vii. **"Replacement labor based on similar project."**

UAF Response to Comment 5c(vii).
The catalyst replacement manhours were assumed to be comparable to those manhours determined in a similar project. The UAF consultant indicates that the project was prepared for a confidential client. UAF believes that the labor hour estimate is appropriate for purposes of this analysis.

viii. "Labor cost based on similar project."

UAF Response to Comment 5c(viii):
The catalyst replacement labor rate was assumed to be comparable to the catalyst replacement labor rate determined in a similar project. The UAF consultant indicates that the project was prepared for a confidential client. The labor rate is likely conservatively low because the cost is not reflective of 2017 labor rates. UAF believes the rate is representative of labor costs for purposes of this analysis.

d. **The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – it is not appropriate to include a 30% contingency factor based on this accuracy range.**

UAF Response to Comment 5d:
The capital costs for an SCR system on the CFB Boiler were provided by Babcock & Wilcox (B&W). The estimate did not include any contingency costs. B&W did indicate that minimal space for an SCR retrofit is available. The arrangement to add SCR would be very complicated arrangement. This issue was not otherwise factored into the budgetary estimates provided. Because preparing a BACT analysis requires obtaining vendor pricing information without knowing the exact final emission limits, the vendor could not be provided with a precise emissions target. The vendor therefore must rely upon their general experience of what percent reduction could be achieved by an SCR system. Applying a contingency factor in the cost effectiveness evaluation seems both practical and appropriate. Use of a contingency factor for costs associated with control device retrofits is also consistent with a Boiler MACT compliance feasibility study prepared by SCI for a confidential client with six coal fired boilers. Please see also the UAF response to Comment 5c(v) above.

A contingency cost of 30 percent was applied to equipment and material costs, direct installation costs, and engineering and procurement costs in the BACT analysis for the SCR systems on the combustion turbines at the Exxon Mobil Point Thomson Production Facility. Please see Page 23 of the Technical Analysis Report (TAR) to Permit No. AQ1261TP01 Consistent with that ADEC-approved analysis, UAF believes that 30 percent is an appropriate ratio for the EU 113 SNCR cost analysis.

UAF notes that removing the contingency factor from the cost analysis calculation results in a cost effectiveness of $28,425/ton of NO_x removed (as opposed to $33,915/ton when including the 30 percent contingency). Because of the contingency factor does not alter the result that SCR cannot be determined to be BACT for EU 113.

6. EU 3 Mid-Sized Diesel Boiler: PTE. - **Detailed basis must be provided for the NO_x PTE of 138.8**

tpy for EU 3 used in the calculations. Note that page 19 of the Title V statement of basis states that emissions from this boiler "in terms of ton/yr were never and will not be limited". Based on the proposed BACT limit of 0.2 lb/MMBtu for good combustion practices, it appears the PTE should, at a minimum, reflect full load operation at this emission rate for 8,760 hours/year (about 150 tpy). If PTE is based on the baseline emission rate used in the FuelTech quote (0.175 lb/MMBtu), the BACT limit proposed for good combustion practices should be 0.175 lb/MMBtu as well.

UAF Response to Comment 6:
The baseline NO_x emission rate of 0.175 lb/MMBtu is an emission rate which Fuel Tech used to prepare a cost estimate for an SCR system. Assuming an existing NO_x emission rate for EU 3 was necessary to prepare a cost estimate for a NO_x emission control system. (The vendor could also not be provided with a precise emissions target, because the nature of a BACT analysis requires obtaining vendor pricing without knowing the exact final emission limit.) The baseline NO_x emission rate of 0.175 lb/MMBtu is not a vendor-guaranteed emission rate. Fuel Tech is the SCR controls system vendor, but is not the vendor that manufactured EU 3.

EU 3 was installed in 1970 and is almost 50 years old. NO_x emission rates depend on combustion efficiency, the amount of fuel-bound nitrogen, and several other factors. The exact NO_x emission profile of EU 3 is not known. (Please refer to the letter from Bulrick dated February 5, 2016, provided in Appendix B of the UAF BACT analysis.) UAF does not wish to commit to a BACT limit which is less than 0.2 lb/MMBtu due to these unknowns. (The 40 CFR 60 Subpart Db NSPS NO_x emission limit is also 0.2 lb/MMBtu. The AP-42 emission factor of 24 lb/1,000 gallons of diesel (Table 1.3-1) is dependent on fuel heat content. Assuming a diesel heating value of 0.137 MMBtu/gallon, the resulting emission rate is 0.175 lb/MMBtu, which is less than the NSPS limit.) UAF believes that 0.2 lb/MMBtu is an appropriate and reasonable BACT limit for EU 3, given the age of the boiler and the unknown variables involved.

7. EU 3 Mid-Sized Diesel Boiler: LNB/FGR
   a. This technology is eliminated based on cost effectiveness calculated assuming actual emissions. All cost analyses and BACT determinations must be based on PTE.

UAF Response to Comment 7a:
The cost analysis for LNB/FGR emission controls on EU 3 based on potential to emit (PTE) is presented in the BACT report that UAF submitted to ADEC. The cost effectiveness of LNB/FGR for EU 3 is $3,634 per ton of NO_x removed, as shown in Table 3-10 and discussed on page 40 of the report.

EU 3 is oil-fired and is operated as a backup boiler. Recent actual NO_x emissions are less than five percent of PTE for EU 3. The new CFB boiler, EU 11-3, which is currently being installed, will be more reliable than the existing coal-fired boilers which have been the primary source of steam at the UAF Central Heat and Power Plant (CHPP). EU 3 will continue in this backup role and so is not expected to be operated often. The actual emissions reductions achieved through installing LNB/FGR would be

minimal (i.e., less than 4 tons per year of NO_x removed). The effective cost of installing the controls would be approximately $35,500 per ton of NO_x removed, as discussed on page 41 of the report.

UAF understands that RACT cost analyses are typically based on PTE as opposed to actual emissions. UAF also understands that RACT decisions are based on case-by-case analysis. As a result, an exception to this typical approach is appropriate in this case because:

- *EU 3 has a long history of infrequent use as backup boiler;*
- *The installation of EU 11 is expected to further reduce the operating frequency of EU 3; and*
- *The cost effectiveness of installing LNB/FGR equipment on EU 3 is very high based on the expected infrequent operation of this boiler.*

As a practical matter, the analysis demonstrates that installing LNB/FGR equipment on EU 3 is not a cost effective method to reduce NO_x emissions from EU 3.

b. **On page 39, the RACT analysis describes this control option as "installation of a new burner on the boiler that is already equipped with a LNB and FGR". The analysis must clarify the current status of the boiler with respect to LNB and FGR technology. If the boiler is already equipped with FGR, detailed technical justification must be provided regarding why the fan(s) and/or ducting must be replaced.**

UAF Response to Comment 7b:
UAF acknowledges that the description provided on page 39 of the RACT analysis is not accurate. EU 3 is not equipped with LNB or FGR technology. The letter from Indeck dated February 3, 2016, provided in Appendix B of the report, states the following: "The low NO_x burners offered here may be operated with the existing boiler force draft (FD) fans with some possible shortness of full MCR steam rating due to the settings of the existing equipment. If lower NO_x levels are desired, these FD fans must be replaced with new FD fans and motors designed to allow for induced flue gas recirculation (FGR) from the boiler flue gas outlet. Optional pricing for these FD fans with FGR capability is provided."

In the letter, Indeck provided information about the existing burners, new LNB without FGR, and new LNB with FGR. The letter states that installing FGR would require the replacement of the existing forced draft (FD) fan and motor.

8. EU 3 Mid-Sized Diesel Boiler: SCR
   a. **The SCR cost analysis cites the following documents and information as the basis for costs and other information relied upon in the analysis, however, documentation for these values and information has not been provided. Documentation must be provided in order to rely upon the cited information in the analysis:**
      1. **"December 2015 price according to Farmer's Coop Association."**

UAE Response to Comment 8a(ii):
The Farmer's Coop Association price web page is available at http://www.farmerscoop.com/pages/custom.php?id=21023. Although prices change slightly over time, UAE believes the $356 cost per ton of urea is representative for this analysis.

ii. **"Replacement labor based on similar project."**

UAE Response to Comment 8a(ii):
The catalyst replacement manhours and labor rate were assumed to be comparable to the manhours determined in a similar project. The UAE consultant indicates that the project was prepared for a confidential client. UAE believes that the labor hour cost estimate for catalyst replacement is appropriate for purposes of this analysis.

iii. **Transport cost direct to site (SCR catalyst). "Based on similar project."**

UAE Response to Comment 8a(iii):
The catalyst transportation cost was assumed to be comparable to transport costs determined in a similar project. The UAE consultant indicates that the project was prepared for a confidential client. UAE believes that the catalyst transport cost estimate is appropriate for purposes of this analysis.

iv. **Transport cost for spent SCR catalyst. "Based on similar project."**

UAE Response to Comment 8a(iv):
The transportation cost for the spent catalyst is assumed to be the same as the transportation cost for a replacement catalyst to UAE.

b. **No basis is provided for the SCR freight cost of $20,000.**

UAE Response to Comment 8b:
The $20,000 freight cost was based on the cost of freight for a smaller SCR application on the ACEP Generator Engine, EU 27. Please refer to the email from Erick Pentrelieff at NC Power Systems to Luis Pacini on November 12, 2015 in Appendix B of the RACT analysis report. NC Power Systems states that freight costs would be in the range of $9,000 to $12,000. The RACT analysis for EU 3 assumes that the SCR system for a larger emission unit would weigh more and consequently have higher freight costs for shipment. The freight cost for an SCR system on EU 3 has been scaled up from the cost provided by NC Power Systems.

c. **Initial performance testing cost is included twice.**

UAE Response to Comment 8c:
The performance testing cost of $10,000 was inadvertently included twice in the cost analysis. Testing was shown under Direct Costs (1)(h) "NOx CEMS Certification Testing" and then again under Indirect Costs (4) "Performance Tests." Correcting the cost analysis to remove the duplicate cost has minimal impact on the calculated cost effectiveness of the control system. The cost effectiveness value changes from $6,416 to $6,440 per ton of NOx removed.

4. **The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – it is not appropriate to include a 30% contingency factor based on this accuracy range**

UAE Response to Comment 8d:
The accuracy range of the Fuel Tech cost estimate is unrelated to the contingency factor. Vendors provide these accuracy ranges because the vendors know certain factors cannot be accounted for in the cost in the absence of any substantial design work. An example of this issue would be any special structural material costs to accommodate seismic requirements, which certainly exist in this application in Interior Alaska.

UAE believes that the use of the 30 percent contingency factor is appropriate due to the following elements:

- *The age of EU 3, its ancillary equipment, and the building envelope in this part of the CHPP. EU 3 was installed in 1970. Installing emission controls (or any new equipment) on this boiler in this portion of the plant requires appropriate contingency to address unforeseen issues which are likely to arise when dealing with a facility which is 38 years old.*
- *A contingency cost of 30 percent was applied to equipment and material costs, direct installation costs, and engineering and procurement costs in the BACT analysis for the SCR systems on the combustion turbines at the Exxon Mobil Point Thomson Production Facility. Please see Page 23 of the Technical Analysis Report (TAR) in Permit No. AQ1231CP01. Consistent with that ADEC-approved analysis, UAE believes that 30 percent is an appropriate ratio for the EU 3SCR cost analysis.*
- *Because preparing a BACT analysis requires obtaining vendor pricing information without knowing the exact final emission limit, the vendor could not be provided with a precise emission target. The vendor therefore must rely upon their general experience of what percent reduction could be achieved by an SCR system. Applying a contingency factor in the cost effectiveness evaluation seems both practical and appropriate. Use of a contingency factor for costs associated with control device retrofits is also consistent with a Boiler MACT compliance feasibility study prepared by SCI*

for a confidential client with six coal-fired boilers

- *The use of urea requires the consideration of material handling, storage, energy requirements for dissolving urea into solution, and maintaining that liquid solution during cold weather months in Interior Alaska. These issues are all likely to result in higher costs.*

UAF notes that removing the contingency factor from the cost analysis calculation results in a cost effectiveness of $7,251/ton of NO_x removed (as opposed to $8,916/ton when including the 30 percent contingency). As discussed in Section 3.3 of the BACT analysis report, UAF believes that the cost estimate for SCR on EU 3 is low. Additionally, the actual emission reductions that would be achieved through installing SCR would be minimal (i.e., less than 6 tons per year of NO_x removed). Please refer to the response to Comment 7a above. The effective cost of installing SCR on EU 3 would be approximately $1 M/ton per ton of NO_x removed when considering the backup role of EU 3 and the expectation that EU 3 will continue to operate at a very low capacity factor.

9. EU 3 Mid-Sized Diesel Boiler: ULSD – The ULSD cost analysis is based on "review of UAF's fuel costs from FY 2011 through 2016. Average of the FY 2014 through 2016 is used, which is 28 cents per gallon more to use ULSD." The documents forming the basis for this information must be submitted in order to rely on this information for purposes of the analysis.

UAF Response to Comment 9:
The fuel prices used in the ULSD cost analysis were obtained from the Oil Price Information Service (OPIS) through the website at https://www.opisnet.com/.

10. EU 8 Large Diesel Fired Engine: Operational Scenario – The NO_x BACT analysis for this unit applies the facility-requested 40 ton per year emission limit, and bases the analysis on an assumed NO_x reduction of only 36 tons (90% reduction from 40 tpy). However, the analysis assumes that the unit operates 8,760 hours/year when calculating the annual O&M costs (i.e., see aqueous ammonia cost). The assumptions underlying the cost analysis are therefore inconsistent. The cost effectiveness analysis must be revised to be consistent based on the assumed operational scenario for the unit. For example, if the unit is assumed to operate uncontrolled for NO_x up to the 40 ton/year limit, the corresponding costs associated with only those limited number of hours may be included. This applies to all annual operating & maintenance costs, including catalyst life.

UAF Response to Comment 10:
EU 8 does not have an operating limit that directly results in operating hours. As a practical matter, UAF agrees that the 40 tpy NO_x emission limit would likely result in engine operating hours which are less than 8,760 hours per year. UAF also notes that the standard methodology of preparing a BACT analysis is not realistic in this case because the 40 tpy NO_x limit remains in effect. Requiring the use of SCR to reduce the NO_x emission rate from EU 8 will not result in an overall emissions reduction. With an emissions reduction of zero tons per year, a cost effectiveness

value cannot be calculated:

Cost effectiveness = (Total Annualized Cost, $) / (Tons of Pollutant Avoided, tpy)

If the denominator of this fraction is zero, no emission control can be determined to be cost effective and therefore BACT. As addressed in Section 3.5 of the BACT analysis report, UAF recommends that the BACT limit require the use of the existing turbocharger, aftercooler, and operations under the existing 40 tpy NO_x limit.

11. EU 8 Large Diesel Fired Engine: SCR – Please provide detailed information regarding the visible emissions described in the BACT analysis which were observed during operation of the SCR currently installed on the large diesel engine. See page 19.

UAF Response to Comment 11:
The visible emissions from EU 8 originate from the Heat Recovery Steam Generator (HRSG), not the existing SCR system. Modifications to the exhaust system would be necessary to enable use of the existing SCR system. For more information on the visible emissions concern, please refer to the Compliance Order by Consent (COBC) dated effective September 25, 2015. (ADEC Enforcement Tracking No. 12-1014-50-0002)

An amendment to the COBC was executed in April 2016 to allow operation of EU 8 following specific maintenance events as recommended by the manufacturer. EU 8 operated for 89 minutes in May 2016 following an overhaul. UAF conducted a Method 9 visible emission observation during the engine run, which indicated excess visible emissions. UAF reported the observations to ADEC as required. Otherwise, EU 8 has not been operated and cannot be operated (except for validation of maintenance events per the COBC amendment).

12. EU 8 Large Diesel Fired Engine: DPF and SCR – The BACT analysis identifies back pressure as a potential technical challenge of installing a DPF to a large diesel engine such as EU 8, but provides no technical analysis or other quantitative or analytical basis for this argument. Further, the BACT analysis determines that an appropriate DPF "likely does not exist" without citing any information from established DPF equipment suppliers. The BACT analysis cites only a single local Fairbanks engine company, whose employee states that the company has "never supplied a DPF with a new engine or for aftermarket use". The information provided forms insufficient basis to reject DPF as technically infeasible and/or not cost effective. The analysis must provide detailed technical analysis of the backpressure issue by an engineering firm or control equipment supplier with the necessary expertise regarding the control technology. In order to establish the availability of a suitable DPF, the analysis must include information regarding these topics from established DPF control equipment suppliers. The availability of this control technology is not limited to DPF equipment currently available "off the shelf". UAF must explore whether manufacture of an appropriate DPF for this emission unit is technically feasible, and conduct an emission unit specific cost analysis following the EPA Cost Manual.

UAF Response to Comment 12:

EU 8 is a Fairbanks Morse Colt-Pielstick engine. Fairbanks Morse Engine (FME) is a well-established engine manufacturer with considerable technical expertise. FME is not a local Fairbanks engine company. FME is based in Wisconsin and was founded more than 140 years ago. More information on FME is available at www.fairbanksmorse.com.

According to information from an FME representative, a diesel particulate filter (DPF) device is not a commercially available technology for this engine. Please refer to the email from Joe Rubino to Julie Ackerlund of February 24, 2016 in Appendix B of the BACT analysis, which documents the discussion between SCI and FME. As stated in section 4.2.A of the BACT analysis, the RBLC database has no entries for DPF devices installed on large diesel-fired engines. DPF is not currently technically feasible due to the backpressure which results when a filtration system is added to the exhaust stream. Because the UAF research indicates that a DPF device for EU 8 is neither commercially available nor technically feasible, a cost analysis for DPF technology will not be prepared.

Please note that UAF provided a BACT analysis for $PM_{2.5}$ direct emissions as a courtesy even though the analysis is not required. The UAF campus stationary source is not a constituent major source of $PM_{2.5}$ as described in Section 1.0 of the BACT analysis. As a result, direct $PM_{2.5}$ emissions do not trigger the requirement to prepare a BACT analysis, and BACT limits for $PM_{2.5}$ emissions from emission units at UAF are not required elements of the State Implementation Plan (SIP).

13. **EU 27 ACEP Generator - The BACT analysis includes evaluations of SCR and DPF as applied individually for control of NO_x and $PM_{2.5}$ respectively, from this emission unit, however a combination SCR/DPF was not evaluated. The analysis must be revised to include a cost effectiveness analysis for this combined control technology.**

UAF Response to Comment 13:
NC Power Systems supplied a capital cost for a combined SCR/DPF control system along with the cost estimate for the separate DPF and SCR packages. Please refer to the email from Erick Pomranke at NC Power Systems to Lois Epstein on November 11, 2015 in Appendix B of the BACT analysis report. UAF has prepared a cost effectiveness analysis using the combined SCR/DPF capital cost. The analysis uses the existing SCR cost analysis submitted in the BACT report as a starting point and adjusts for the increased capital cost and the mass of pollutants controlled to account for a combined NO_x/$PM_{2.5}$ emission reduction. The cost effectiveness for a combined SCR/DPF is not economically feasible. The cost effectiveness is $13,240 per ton of pollutant (NO_x and $PM_{2.5}$) removed. This cost analysis is presented in Attachment A.

Please note that UAF provided a BACT analysis for $PM_{2.5}$ direct emissions as a courtesy even though the analysis is not required. The UAF campus stationary source is not a constituent major source of $PM_{2.5}$ as described in Section 1.0 of the BACT analysis. As a result, direct $PM_{2.5}$ emissions do not trigger the requirement to prepare a BACT analysis, and BACT limits for $PM_{2.5}$ emissions from emission units at UAF are not required elements of the SIP.

ADEC Draft Comments

12. For the purposes of this BACT analysis the cost analysis for each emissions control for each of EUs 4 and 8 should be based on the assumption that the 40 tpy NOx limit will be consumed by the EU being evaluated. Under the current permitting limit it is possible for one of EUs 4 and 8 to be the sole contributor to the 40 tpy of NOx in any given 12 month rolling period. Additionally, the 10 percent capacity limit for EU 4 was removed with the issuance of Minor Permit No. AQ0316MSS04 on August 4, 2016, and is therefore no longer applicable as limited operation for EU 4. Please revise the PTE and cost analysis for these units.

UAF Response to ADEC Comment 12:
The 10 percent capacity factor limit on EU 4 remains in effect. Please refer to Conditions 17 and 61.2 of Permit No. AQ0116TVP02, Revision 3, and page 20 in the Statement of Basis for the Title V permit. The capacity factor limit is an owner requested limit (ORL) which enables EU 4 to be exempt from a NOx emission standard and monitoring requirements in the New Source Performance Standards (NSPS) in 40 Code of Federal Regulations (CFR) 60 Subpart Db. Permit No. AQ0316MSS04 was issued on February 15, 2013, and addresses EUs 9A, 19, 20, and 21. That permit did not address EU 4 and did not remove the 10 percent capacity factor limit. Permit No. AQ0316MSS05 was issued on August 4, 2016 and does not include the capacity factor limit. Per Item 4 under Section 4 of the Technical Analysis Report for Permit No. AQ0316MSS05, the NSPS requirements are not included in the minor permit because those requirements have since been incorporated into the operating permit. As a result, the PTE and cost analyses for EU 4 in the BACT analysis are correctly based on the 10 percent capacity factor limit. [Refer to Tables 1-3, 1-5, 3-3, 3-13, 5-2, and 5-9 in the analysis report.]

With respect to EU 8, baseline NO_x and SO_2 PTE are such as to 40 tpy to reflect that EU 8 could consume either or both of the entire NO_x and/or SO_2 annual emission limits. Please refer to Tables 1-2, 1-3, 1-5, 3-3, and 5-2. No revisions to the PTE or cost analyses for EU 8 are needed as a result.

13. Describe for each emission unit type, what constitutes good combustion practices. Include any work or operational practice that will be implemented and describe how continuous compliance with good combustion practices will be achieved.

UAF Response to ADEC Comment 13:

Emission Unit Type

- ***Mid-sized Diesel-Fired Boilers** (EUs 3 and 4) – 180.9 MMBtu/hr*
  - *Optimize air to fuel ratio*
  - *Conduct regular maintenance*
  - *Regular Cleaning of Boiler.*
    - *Any residue, such as soot or scale that coats the heat transfer surfaces of the boiler will reduce its efficiency and also increase the likelihood of equipment*

failure. Cleaning this surface according to manufacturer's recommendations is important to maintaining optimum boiler performance and equipment life.

- Water Chemical Treatment
  - Good boiler water chemical treatment, depending on the dissolved minerals in the makeup of the water.
  - Poor water treatment practices can result in scale accumulation on the water side of the tubes.
  - Annual inspections of boilers should include a thorough examination of the water side surfaces for evidence of scaling and corrosion. Even a thin layer of scale interferes with heat transfer and thereby decreases combustion efficiency.
- Minimize Boiler Blowdown
  - Having too many total dissolved solids (TDS's) in the boiler water can cause scale and reduce boiler efficiency. Therefore, it is necessary to maintain the solids below certain limits.
  - Excessive blowing down will reduce useful output and lower efficiency.

- **Large Diesel-Fired Engine** (EU 8) – 13,266 hp
  - Optimize air to fuel ratio.
  - Operate the engine such that the following combustion air management conditions are met:
    - a sufficient quantity of oxygen is available to ensure complete combustion,
    - a sufficient amount of diluent (i.e., EGR) is present to control the combustion temperature,
    - the temperature and pressure (density) of the charge air is controlled,
    - suitable bulk motion and kinetic energy is imparted to the charge air in the cylinder to support the mixing of air, fuel and intermediate combustion products, and
    - the size and concentration of impurities such as dust and dirt is acceptable.
  - Manage the charge air temperature by:
    - Cooling high temperature air in boosted diesel engines and
    - Heating low temperature air to facilitate engine start-up and warm-up at low ambient temperatures.
  - Preheat engine.
  - Balance cylinder firing pressures.
  - Recirculate exhaust gas back into the intake system.
- **Medical/Pathological Waste Incinerator** (EU 9A)
  - EUs will be operated and maintained in accordance with manufacturer specifications.
- **Small Boiler** (EUs 19 – 21)
  - EUs will be operated and maintained in accordance with manufacturer specification.
- **Small Engine** (EU 27)
  - EUs will be operated and maintained in accordance with manufacturer specification.
- **Large Coal-Fired Boiler** (EU 113) – 295.6 MMBtu/hr
  - Optimize air to coal ratio by reducing excess air or excess O2.
  - Minimize air-in leakage and air heater cross leakage to minimize fan power and flue gas heat losses.
  - Optimize coal fineness and moisture content based on the coal being burned in the unit.
  - Maintain boiler burners such that fuel distribution is evenly dispersed.
  - Maintain good water quality to prevent fouling of tube surfaces and poor heat transfer.

- *Inspect and maintain insulation, boiler tubes, and access door seals.*

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

DIVISION OF AIR QUALITY
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[illegible]
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September 13, 2018

Frances Ingrigg, Director
Environmental Health, Safety & Risk Management
University of Alaska Fairbanks
PO Box 758145
Fairbanks, AK 99775

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum for University of Alaska Fairbanks by November 1, 2018

Dear Ms. Ingrigg:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that the University of Alaska Fairbanks and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to a Serious Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measure (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as the University of Alaska Fairbanks. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analysis is a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an email to Ms. Ingrigg on May 11, 2017 notifying her of the reclassification to Serious and included

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 [illegible]

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(a)(2) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

[3] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

a request for the BACT analysis to be completed by August 8, 2017. The BACT analysis was submitted by email to ADEC on February 8, 2017 from University of Alaska Fairbanks. It included emission units found in Operating Permit AQ0316TVP02 Revision 1 and Minor Permit AQ0316MSS06 Revision 2.

On March 22, 2018, ADEC released a preliminary draft of the BACT determination for the University of Alaska Fairbanks for public discussion on its website at: https://dec.alaska.gov/air/anpms/communities/fnks.pm2_5_serious_sip_dev.htm#current. As indicated in the release, this document is a work in progress. ADEC received additional information from the University of Alaska Fairbanks and the EPA on the preliminary draft BACT determination and expects to make changes to the determination based upon this input. Therefore, ADEC is requesting additional information from the University of Alaska Fairbanks to assist it in making a legally and practicably enforceable BACT determination for the source.

Specifically, ADEC requests that the University of Alaska Fairbanks review the cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the cost effectiveness calculations and indicates that the model is intended to calculate estimated total project cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent and the gross generating capacity of the plant. Please use this spreadsheet to calculate the cost effectiveness of SO_2 removal in dollars per ton and identify all assumptions and technical justifications used in the analysis.

If ADEC does not receive a response to this information request by November 1, 2018, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facility's infrastructure and without additional information, may select a more stringent BACT for your facility in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public review along with any precursor demonstrations and BACM analyses before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes a final BACT determination for the University of Alaska Fairbanks, it must include the determination in Alaska's Serious SIP that then ultimately requires approval by EPA.[1] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented no[t] later to June 9, 2021 – 4 years after reclassification.[2]

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM) consideration. MSMs will be a required element of the new implementation plan if the State applies

[1] https://www.gpo.gov/fdsys/pkg/CFR-2011-title42-vol3/pdf/CFR-2011-title42-vol3-chapI-subchapI-partD-subpartA-sec7513a.pdf
[2] 40 CFR 51.1010(4)

for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

ADEC appreciates the cooperation that we've received from the University of Alaska Fairbanks. ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Denise Koch, Director
Division of Air Quality

Enclosures:

September 10, 2018	ADEC Request for Additional Information for UAF BACT Analysis
May 21, 2018	EPA Comments on ADEC Preliminary Draft Serious SIP Development Materials for the Fairbanks Serious PM-2.5 nonattainment Area
March 22, 2018	UAF Comments Addressing the Preliminary Best Available Control Technology Determination for University of Alaska Fairbanks
October 20, 2017	Request for Additional Information for UAF BACT Analysis
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for UAF

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Cindy Heil, ADEC/Air Quality
Brittany Crutchfield, ADEC/Air Quality
Frances Isgrigg/University of Alaska Fairbanks
Dan Brown, EPA Region 10
Aaron Simpson, ADEC/Air Quality
Jim Plosay, ADEC/ Air Quality
Deanna Huff, ADEC/ Air Quality
Tim Hamlin, EPA Region 10
Zach Hedgpeth, EPA Region 10

ADEC Request for Additional Information
University of Alaska Fairbanks
BACT Technical Memorandum Review
SLR Report January 2017

September 10, 2018

Please address the following comments by providing the additional information identified by November 1, 2018. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public comment. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public comment period or based upon the new information provided in response to this information request.

This document does not represent a final BACT determination by ADEC. Please contact Aaron Simpson at aaron.simpson@alaska.gov with any questions regarding ADEC's comments.

Draft Comments

1. Equipment Life – Page 45 (Adobe page number) of the analysis[1] states "a standardized ten year return on investment at seven percent interest rate is assumed." This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in interior Alaska experiences more wear and tear than equipment in moderate climates." The 10 year equipment life assumption is based on the harsh climate, evidence of which must be provided. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers. A 20 year equipment life may be used for SNCR, but a 30 year equipment life is required for the other control devices (i.e., SCR, Wet FGD, DSI, circulating dry scrubber (CDS), and SDA) unless detailed documentation can be provided.

2. Interest Rate – Page 45 (Adobe page number) of the analysis[1] states "a standardized ten year return on investment at seven percent interest rate is assumed." All cost analysis must use the current bank prime interest rate. This can be found online at; https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table). Please revise the cost analyses as appropriate.

3. CFB Boiler: Wet Scrubbing – Clearly explain the basis for excluding wet scrubbing in the BACT analysis.

4. CFB Boiler: SDA and DSI
    a. As part of their Oklahoma Best Available Retrofit Technology (BART) Federal Implementation Plan (FIP) final rule for regional haze[2], US EPA Region 6 found that a

[1] University of Alaska Fairbanks, Voluntary Best Available Control Technology Analysis for the Serious $PM_{2.5}$ Non-Attainment Area Classification, Prepared by SLR, January 2017
[2] 76 FR 81728, December 28, 2011

reasonable estimate for equipment life is 30 years for SO_2 control technologies, please provide a detailed explanation for the equipment life listed for the SDA and DSI control technologies.

b. Please provide the documents for the following citations:
   i. "SCI engineering estimates (5 years old) for other SDAs."
   ii. "SCI engineering estimates (5 years old) for other DSI systems"
   iii. "Internal SDA cost study done by SCI in 2010, which indicated 8%."
   iv. "…similar internal SCI SDA cost analysis and other vendor (FTEK SCR) quotes."

5. CFB Boiler: SNCR – Please provide documentation for the following citation in the BACT analysis: Indirect capital costs "18% was used in similar SCR BACT analysis. Assume same amount for SNCR."

6. CFB Boiler: SCR – Please revise the cost analysis submitted using the EPA updated cost manual chapter pertaining to SCR[3]. Documentation must be provided for the following cited information:
   a. "Cost of startup spares indicated as a percentage of equipment cost per similar project."
   b. Fab Site Vendor "days based on similar project."
   c. Onsite Vendor "days based on similar project."
   d. Indirect capital costs "18% was used in similar SCR BACT analysis for smaller CTs."
   e. "Replacement labor based on similar project."
   f. "Labor cost based on similar project."

   The Department notes that records can be submitted to the Department under the provisions of the Alaska Statute dealing with confidentiality of records under AS 46.14.520.

7. EU 3 Mid-Sized Diesel Boiler: SCR
   a. Please provide the documentation for following citations in the BACT analysis.
      i. "Replacement labor based on similar project."
      ii. Transport cost direct to site (SCR catalyst). "Based on similar project."
      iii. Transport cost for spent SCR catalyst. "Based on similar project."
   b. No basis is provided for the SCR freight cost of $20,000.
   c. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual, provide justification for 30% contingency factor.

   The Department notes that records can be submitted to the Department under the provisions of the Alaska Statute dealing with confidentiality of records under AS 46.14.520.

8. EU 8 Large Diesel Fired Engine: DPF and SCR – The BACT analysis identifies back pressure as a potential technical challenge of installing a DPF to a large diesel engine such as EU 8, please provide a technical analysis basis for this statement.

9. SO_2 Control Device: Circulating Dry Scrubber – Please include CDS in the analysis for SO_2 emission controls. It is required that all control devices are evaluated for BACT.

10. Control Technology Availability – Documentation from multiple control technology vendors must be provided in order to eliminate a control technology based on unavailability. Please provide additional information regarding the lack of availability for control technologies

[3] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

eliminated on this basis. This additional information should not be provided from the EU's manufacturer.

11. Retrofitting – Please provide additional information regarding technologies eliminated due to space constraints and/or complications. Detailed information must be provided in support of eliminating a control technology based on space requirements. Additionally, documentation regarding any inclusion of retrofitting cost must be provided. Please provide site-specific quotes for retrofitting requirements.

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November 1, 2018

Denise Koch, Director
Division of Air Quality
Alaska Department of Environmental Conservation
410 Willoughby Avenue, Suite 303
PO Box 111800
Juneau, Alaska 99811-1800

Subject: University of Alaska Fairbanks
Response to the September 13, 2018 ADEC request for additional information for the Best Available Control Technology Technical Memorandum

Dear Ms. Koch

Attached is the response by the University of Alaska Fairbanks to your September 13, 2018 request for additional information for the Best Available Control Technology Technical Memorandum for University of Alaska Fairbanks (UAF).

If you have any questions related to this response, please feel free to contact me at [redacted]

Sincerely,

FDR

Frances Ingrigg, PE
Director, Environmental, Health, Safety and Risk Management
University of Alaska Fairbanks
1855 Marika Road
Fairbanks, Alaska 99775-8145
P: 907-474-5487 | F: 907-474-5489 | C: 907-590-5809

Enclosures:
September 13, 2018 ADEC Request for Additional Information on UAF BACT Analysis
November 1, 2018 UAF Response to September 13, 2018 ADEC Request letter

cc: (via email) Frances Ingrigg, UAF Cindy Heil, ADEC/Air Quality Deanna Huff, ADEC/Air Quality
Courtney Kimball, SLR Russ Steiger, UAF

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THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

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September 13, 2018

Frances Ingrigg, Director
Environmental Health, Safety & Risk Management
University of Alaska Fairbanks
PO Box 758145
Fairbanks, AK 99775

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum for University of Alaska Fairbanks by November 1, 2018

Dear Ms. Ingrigg:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that the University of Alaska Fairbanks and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to a Serious Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measure (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as the University of Alaska Fairbanks. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analysis is a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an email to Ms. Ingrigg on May 11, 2017 notifying her of the reclassification to Serious and included

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 [illegible]

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(c)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.

[3] [illegible], Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

a request for the BACT analysis to be completed by August 8, 2017. The BACT analysis was submitted by email to ADEC on February 8, 2017 from University of Alaska Fairbanks. It included emission units found in Operating Permit AQ0316TVP02 Revision 1 and Minor Permit AQ0316MSS06 Revision 2.

On March 22, 2018, ADEC released a preliminary draft of the BACT determination for the University of Alaska Fairbanks for public discussion on its website at: http://dec.alaska.gov/air/anpms/communities/fnks_pm2.5_serious_sip_development. As indicated in the release, this document is a work in progress. ADEC received additional information from the University of Alaska Fairbanks and the EPA on the preliminary draft BACT determination and expects to make changes to the determination based upon this input. Therefore, ADEC is requesting additional information from the University of Alaska Fairbanks to assist it in making a legally and practicably enforceable BACT determination for the source.

Specifically, ADEC requests that the University of Alaska Fairbanks review the cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the cost effectiveness calculations and indicates that the model is intended to calculate estimated total project cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent and the gross generating capacity of the plant. Please use this spreadsheet to calculate the cost effectiveness of SO_2 removal in dollars per ton and identify all assumptions and technical justifications used in the analysis.

If ADEC does not receive a response to this information request by November 1, 2018, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facility's infrastructure and without additional information, may select a more stringent BACT for your facility in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public review along with any precursor demonstrations and RACM analyses before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes a final BACT determination for the University of Alaska Fairbanks, it must include the determination in Alaska's Serious SIP that then ultimately requires approval by EPA.[1] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented prior to June 9, 2021 – 4 years after reclassification.[2]

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirement, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM) consideration. MSMs will be a required element of the state implementation plan if the State applies

[1] https://www.gpo.gov/fdsys/pkg/CFR-2013-title40-vol3/pdf/CFR-2013-title40-vol3-sec51-1010.pdf
[2] 40 CFR 51.1010(6)

for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

ADEC appreciates the cooperation that we've received from the University of Alaska Fairbanks. ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Jeremy Koch, Director
Division of Air Quality

Enclosures:

September 10, 2018	ADEC Request for Additional Information for UAF BACT Analysis
May 21, 2018	EPA Comments on ADEC Preliminary Draft Serious SIP Development Materials for the Fairbanks Serious PM-2.5 nonattainment Area
March 22, 2018	UAF Comments Addressing the Preliminary Best Available Control Technology Determination for University of Alaska Fairbanks
October 20, 2017	Request for Additional Information for UAF BACT Analysis
May 11, 2017	Serious SIP BACT due date email
April 24, 2013	Voluntary BACT Analysis for UAF

cc: Larry Hamig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Cindy Heil, ADEC/Air Quality
Brittany Crutchfield, ADEC/Air Quality
Frances Ingregg/University of Alaska Fairbanks
Dan Brown, EPA Region 10
Aaron Simpson, ADEC/Air Quality
Jim Plosay, ADEC/ Air Quality
Deanna Huff, ADEC/ Air Quality
Tim Hamlin, EPA Region 10
Zach Hodgpeth, EPA Region 10

ADEC Request for Additional Information
University of Alaska Fairbanks
BACT Technical Memorandum Review
SLR Report January 2017

September 10, 2018

Please address the following comments by providing the additional information identified by November 1, 2018. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public comment. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public comment period or based upon the new information provided in response to this information request.

This document does not represent a final BACT determination by ADEC. Please contact Aaron Simpson at aaron.simpson@alaska.gov with any questions regarding ADEC's comments.

Draft Comments

1. Equipment Life – Page 45 (Adobe page number) of the analysis[1] states "a standardized ten year return on investment at seven percent interest rate is assumed." This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in interior Alaska experiences more wear and tear than equipment in moderate climates." The 10 year equipment life assumption is based on the harsh climate, evidence of which must be provided. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers. A 20 year equipment life may be used for SNCR, but a 30 year equipment life is required for the other control devices (i.e., SCR, Wet FGD, DSI, circulating dry scrubber (CDS), and SDA) unless detailed documentation can be provided.

2. Interest Rate – Page 45 (Adobe page number) of the analysis[1] states "a standardized ten year return on investment at seven percent interest rate is assumed." All cost analysis must use the current bank prime interest rate. This can be found online at: https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table). Please revise the cost analyses as appropriate.

3. CFB Boiler: Wet Scrubbing – Clearly explain the basis for excluding wet scrubbing in the BACT analysis.

4. CFB Boiler: SDA and DSI
   a. As part of their Oklahoma Best Available Retrofit Technology (BART) Federal Implementation Plan (FIP) final rule for regional haze[2], US EPA Region 6 found that a

[1] University of Alaska Fairbanks, Voluntary Best Available Control Technology Analysis for the Serious PM$_{2.5}$ Non-Attainment Area Classification. Prepared by SLR, January 2017

[2] 76 FR 81728, December 28, 2011

reasonable estimate for equipment life is 30 years for SO_2 control technologies, please provide a detailed explanation for the equipment life listed for the SDA and DSI control technologies.

b. Please provide the documents for the following citations:
   i. "SCI engineering estimates (5 years old) for other SDAs."
   ii. "SCI engineering estimates (5 years old) for other DSI systems"
   iii. "Internal SDA cost study done by SCI in 2010, which indicated 8%."
   iv. "...similar internal SCI SDA cost analysis and other vendor (FTEK SCR) quotes."

5. CFB Boiler: SNCR – Please provide documentation for the following citation in the RACT analysis: Indirect capital costs "18% was used in similar SCR RACT analysis. Assume same amount for SNCR."

6. CFB Boiler: SCR – Please revise the cost analysis submitted using the EPA updated cost manual chapter pertaining to SCR[1]. Documentation must be provided for the following cited information:
   a. "Cost of startup spares indicated as a percentage of equipment cost per similar project."
   b. Fab Site Vendor "days based on similar project."
   c. Onsite Vendor "days based on similar project."
   d. Indirect capital costs "18% was used in similar SCR RACT analysis for smaller CTs."
   e. "Replacement labor based on similar project."
   f. "Labor cost based on similar project."

   The Department notes that records can be submitted to the Department under the provisions of the Alaska Statute dealing with confidentiality of records under AS 46.14.520.

7. EU 3 Mid-Sized Diesel Boiler: SCR
   a. Please provide the documentation for following citations in the RACT analysis
      i. "Replacement labor based on similar project."
      ii. Transport cost direct to site (SCR catalyst). "Based on similar project."
      iii. Transport cost for spent SCR catalyst. "Based on similar project."
   b. No basis is provided for the SCR freight cost of $20,000.
   c. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual, provide justification for 30% contingency factor.

   The Department notes that records can be submitted to the Department under the provisions of the Alaska Statute dealing with confidentiality of records under AS 46.14.520.

8. EU 8 Large Diesel Fired Engine: DPF and SCR – The RACT analysis identifies back pressure as a potential technical challenge of installing a DPF to a large diesel engine such as EU 8; please provide a technical analysis basis for this statement.

9. SO_2 Control Device: Circulating Dry Scrubber – Please include CDS in the analysis for SO_2 emission controls. It is required that all control devices are evaluated for RACT.

10. Control Technology Availability – Documentation from multiple control technology vendors must be provided in order to eliminate a control technology based on unavailability. Please provide additional information regarding the lack of availability for control technologies

[1] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

eliminated on this basis. This additional information should not be provided from the EU's manufacturer.

11. Retrofitting – Please provide additional information regarding technologies eliminated due to space constraints and/or complications. Detailed information must be provided in support of eliminating a control technology based on space requirements. Additionally, documentation regarding any inclusion of retrofitting cost must be provided. Please provide site-specific quotes for retrofitting requirements.

ATTACHMENT 1

The University of Alaska Fairbanks (UAF) received a request for additional information regarding the Best Available Control Technology (BACT) analysis from the Alaska Department of Environmental Conservation (ADEC) on September 13, 2018. This request included a set of 11 draft comments and a request in the body of the letter pertaining to the sulfur dioxide (SO_2) BACT determination. The comments are repeated below, followed by the UAF response to each comment in italicized font:

1. Equipment Life – Page 45 (Adobe page number) of the analysis states "a standardized ten year return on investment at seven percent interest rate is assumed." This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in interior Alaska experiences more wear and tear than equipment in moderate climates." The 10 year equipment life assumption is based on the harsh climate, evidence of which must be provided. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers. A 20 year equipment life may be used for SNCR, but a 30 year equipment life is required for the other control devices (i.e., SCR, Wet FGD, DSI, circulating dry scrubber (CDS), and SDA) unless detailed documentation can be provided.

   UAF Response to Comment 1:
   Consistent with established ADEC practice and previously approved Prevention of Significant Deterioration (PSD) permitting BACT analyses, a 10-year equipment life was initially used in the calculation of the capital recovery factor for the UAF BACT analysis. This equipment life was subsequently increased to 15 years for the Emissions Unit (EU) 113 spray dryer absorber (SDA) and dry sorbent injection (DSI) BACT analyses. This 10- to 15-year equipment life timeframe is appropriate for equipment operated in the harsh Alaska climate. Two recent permits with BACT analyses based on a 10-year life are Permit No. AQ0237CPT04 (see footnote to Table B-4 of the Technical Analysis Report) and Permit No. AQ0083CPT06 (see page 24 of Technical Analysis Report). Please note that UAF addressed similar questions in the December 21, 2017 response to EPA Region 10 and ADEC comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.

   The EPA Air Pollution Control Cost Manual (sixth edition, EPA/452/B-02-001, Control Cost Manual) uses equipment lifetimes between five and 30 years. Ten, 15, and 20-year lifespans are frequently used in the manual. In the information request, ADEC states that using "a 30 year equipment life is required for the other control devices [i.e., SCR Wet FGD, DSI, circulating dry scrubber (CDS), and SDA] unless detailed documentation can be provided." UAF notes that the Control Cost Manual is a guidance document as opposed to being a regulation. UAF is not aware of a rule or rulemaking that requires the use of a specific equipment life. UAF requests that ADEC provide the regulatory citations that mandate the use of a 30-year equipment life.

   Using a 10-year equipment life timeframe is appropriate in this case because of the harsh Alaska climate. One aspect of this harsh climate is the extreme ambient temperature range that is experienced in Fairbanks. The recorded ambient temperature ranges from -66 degrees Fahrenheit

(°F) to 96 °F, a span of 162 °F. The mean ambient temperature is less than 32 °F from October to April. Another aspect of this harsh climate is the occurrence of wintertime temperature inversions and the subsequent formation of ice fog. Snowfall is also a factor in defining the harsh climate, with daily recorded snowfalls of up to 16 inches and monthly recorded snowfalls of up to 65 inches. Climate data for the Fairbanks area is provided in Attachment 2.

The result of this harsh climate is a shorter equipment life due to the stress placed on materials and operating systems. Practical experience in Interior Alaska has demonstrated that items exposed to these ambient conditions (such as exterior piping (even if insulated and/or buried), any equipment with moving parts, and exhaust stacks and vents) require more frequent routine maintenance, are prone to more frequent failure, and have a shorter useful life. The harsh climate also impacts equipment located within structures. For example, DSI sorbent (or any other material) that is delivered in winter would arrive at the outside ambient temperature. Bringing that cold material inside can result in detrimental temperature stress, condensation issues, or other impacts to the equipment that is otherwise not exposed to ambient conditions.

2. Interest Rate – Page 45 (Adobe page number) of the analysis states "a standardized ten year return on investment at seven percent interest rate is assumed." All cost analysis must use the current bank prime interest rate. This can be found online at; https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table). Please revise the cost analyses as appropriate.

UAF Response to Comment 2:
UAF notes that the Control Cost Manual is a guidance document, not a regulation. Chapter 2 of the Control Cost Manual (updated February 1, 2018) addresses the importance of using "appropriate private nominal interest rates." Use of the bank prime rate is presented as an option if firm-specific nominal interest rates cannot be estimated or verified. UAF does not currently have sufficient information about potential interest rates to enable the selection of a specific interest rate for a UAF project. While UAF does not necessarily agree that the bank prime rate is the most appropriate rate, the cost analyses have been revised to reflect the current bank prime interest rate of 5.25 percent per year. UAF obtained the rate of 5.25 percent from the H.15 release (October 25, 2018) on the Federal Reserve website (https://www.federalreserve.gov/releases/h15/). The table below provides the resulting cost effectiveness values in terms of dollar per ton of pollutant avoided.

Applicable Table in UAF Voluntary BACT Analysis	Emissions Unit	Control Device	Project Life	Cost Effectiveness ($ per ton avoided) at 5.25% interest
5-5	113	SCR	10[a]	$27,013
			20[a]	$20,673
5-7	113	SNCR	10	$9,547
5-9	3	SCR	10	$9,086
5-11	3	LNB/FGR	10	$3,396
5-13	4	LNB/FGR	10	$176,906
5-15	8	SCR	10	$26,244
5-17	27	SCR	10	$11,985
4-5	19, 20, 21	PM Scrubber	10	$44,135
4-7	27	DPF	10	$16,239
4-9	9A	Fabric Filter	10	$709,916
5-5	113	SDA	10[a]	$17,992
			15[a]	$10,824
5-7	113	DSI	10[a]	$8,464
			15[a]	$8,032
5-8	3	ULSD	N/A	$1,084
5-9	4	ULSD	N/A	$1,082
5-10	8	ULSD	N/A	$971
N/A	27	SCR/DPF combination[c]	10	$10,590

Notes:
[a] A 10-year life was used in the BACT analysis that UAF provided to ADEC in January 2017. Costs based on a 20-year life were provided in the December 2017 UAF response to an ADEC information request.
[b] A 10-year life was used in the BACT analysis that UAF provided to ADEC in January 2017. Costs based on a 15-year life were provided in the December 2017 UAF response to an ADEC information request.
[c] This technology was not addressed in the BACT analysis that UAF provided to ADEC in January 2017. The cost for combined SCR and DPF for EU 27 was provided in the December 2017 UAF response to an ADEC information request.

3. CFB Boiler: Wet Scrubbing - Clearly explain the basis for excluding wet scrubbing in the BACT analysis.

UAF Response to Comment 3:
Please note that UAF addressed a similar question in the December 21, 2017 response to EPA Region 10 and ADEC comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.

Wet scrubbing is an older technology that has been in existence for approximately 100 years.

Wet scrubbers are expensive, difficult to maintain, require a large footprint, and require high water consumption. Pulverized coal boilers have been equipped with wet scrubbers as post-combustion SO_2 emission controls. Wet scrubbing was not included in the UAF BACT analysis because the UAF boiler is not a pulverized coal boiler. The UAF boiler EU 113 is a circulating fluidized bed (CFB) boiler. The CFB boiler design is a relatively new technology that has been developed and operated in the past few decades. The CFB boiler design is unique in that the scrubbing SO_2 control technology is not post-combustion, but is an integral part of the boiler design. The CFB boiler includes a limestone injection system. The coal is mixed with the limestone to absorb SO_2 emissions as the combustion air passes through the bed.

Wet scrubbing has not been demonstrated in practice for CFB boilers. Because the BACT analysis cannot redefine the source, such as switching a CFB boiler to a pulverized coal boiler, wet scrubbing is not an appropriate technology and was not examined in the UAF SO_2 BACT analysis.

4. CFB Boiler: SDA and DSI

   a. As part of their Oklahoma Best Available Retrofit Technology (BART) Federal Implementation Plan (FIP) final rule for regional haze, US EPA Region 6 found that a reasonable estimate for equipment life is 30 years for SO_2 control technologies. please provide a detailed explanation for the equipment life listed for the SDA and DSI control technologies.

   UAF response to Comment 4a:
   For the reasons discussed in the response to ADEC Comment 1 and provided below, UAF continues to believe that using a 30-year equipment life is not appropriate for SDA and DSI emission control systems as applied to EU 113. As a courtesy, UAF previously re-calculated the cost analysis for SDA and DSI as applied to EU 113 using a 15-year equipment life instead of the 30-year equipment used in the initial BACT analysis provided to ADEC. These recalculated cost effectiveness values were provided to ADEC on December 21, 2017. For SDA, the cost effectiveness would be $11,598 per ton of SO_2 emissions avoided. For DSI, the cost effectiveness would be $8,186 per ton of SO_2 emissions avoided. (Please see the response to ADEC Comment 2 for the cost effectiveness values calculated using the current bank prime interest rate.)

   ADEC cited a proposed federal rulemaking addressing a regional haze determination from EPA Region 6 to support a 30-year equipment life for SDA and DSI. The preamble to that proposed rule includes a discussion of equipment life for SO_2 scrubbers. The preamble states that a prior Oklahoma Federal Implementation Plan (FIP) used a lifetime of 30 years to determine costs for SO_2 scrubbers. As explained in the response to Comment 1, expanding the use of the Oklahoma FIP 30-year equipment life to the EU 113 is not appropriate because the suitability and design of equipment installed in Oklahoma is not the same as the suitability and design of equipment that would be installed in Interior Alaska. This conclusion is consistent with the basic premise that each BACT determination is to be made on a case-by-case basis. Please note that UAF addressed similar questions in the December 21, 2017 response to EPA Region 10 and ADEC.

comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.

As a point of clarification, the Control Cost Manual does not indicate the use of a 30-year equipment life for any SO_2 emission control systems. Instead, the Control Cost Manual, Section 5.2, Chapter 1, paragraph 1.5.2, provides a 15-year equipment life for a wet scrubber, and cites Section 1 of the manual regarding capital recovery costs. The EPA Region 6 use of a 30-year life for SO_2 scrubbers is not consistent with the Control Cost Manual.

A 30-year equipment life for SDA and DSI as applied to EU 113 is inconsistent with EPA long-standing guidance regarding equipment life determinations. The 1990 New Source Review Workshop Manual for Prevention of Significant Deterioration and Nonattainment Area Permitting states on page b.39 of Appendix B that "The economic life of a control system typically varies between 10 to 20 years and longer ***and*** *should be determined consistent with data from EPA cost support documents and the IRS Class Life Asset Depreciation Range System." (Emphasis added.) EU 113 will be a co-generation boiler that will produce steam for campus heat and steam for the generation of electricity. Table B-1 of IRS Publication 946 (2016) provides a class life, or a tax cost recovery period, of 22 years for assets associated with Industrial Steam and Electric Generation and/or Distribution Systems (see Asset Class 00.4). Based on this information, a 30-year equipment life is not consistent with the EPA policy that the economic life of an emission control system should also be consistent with the IRS Class Life Asset Depreciation Range System.*

The conclusion is that the EPA Region 6 decision is not a mandate to base all future SDA and DSI BACT analyses on a 30-year equipment lifespan because:

- *BACT is determined on a case-by-case basis that incorporates site specific conditions;*
- *The EPA Control Cost Manual does not support a 30-year equipment for SDA and DSI; and*
- *EPA Prevention of Significant Deterioration (PSD) and Non-attainment New Source Review (NA-NSR) guidance does not support a 30-year equipment for SDA and DSI.*

b. Please provide the documents for the following citations:
   i. "SCI engineering estimates (5 years old) for other SDAs."

UAF response to Comment 4b(i):
These estimates were based on a Boiler MACT compliance feasibility study prepared by UAF's consultant, Stanley Consultants, Inc. (SCI), for a separate, confidential client. Because the client is not UAF and is confidential, SCI is not able to provide the estimate to UAF. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the

document under the confidential business information (CBI) provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that use of the engineering estimate is appropriate and further documentation is not necessary.

ii. "SCI engineering estimates (5 years old) for other DSI systems"

UAF response to Comment 4b(ii):
These estimates were based on a Boiler MACT compliance feasibility study prepared by UAF's consultant, SCI, for a separate, confidential client. Because the client is not UAF and is confidential, SCI is not able to provide the estimate to UAF. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that use of the engineering estimate is appropriate and further documentation is not necessary.

iii. "Internal SDA cost study done by SCI in 2010, which indicated 8%."

UAF response to Comment 4b(iii):
These estimates were based on a Boiler MACT compliance feasibility study prepared by UAF's consultant, SCI, for a separate, confidential client. Because the client is not UAF and is confidential, SCI is not able to provide the estimate to UAF. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that use of the engineering estimate is appropriate and further documentation is not necessary.

iv. "...similar internal SCI SDA cost analysis and other vendor (FTEK SCR) quotes."

UAF response to Comment 4b(iv):
These estimates were based on a Boiler MACT compliance feasibility study prepared by UAF's consultant, SCI, for a separate, confidential client. Because the client is not UAF and is confidential, SCI is not able to provide the estimate to UAF. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that use of the engineering estimate is appropriate and further documentation is not necessary.

The FTEK SCR quote was provided in Appendix B of the BACT analysis report.

5. CEB Boiler: SNCR – Please provide documentation for the following citation in the BACT

analysis: Indirect capital costs "18% was used in similar SCR BACT analysis. Assume same amount for SNCR."

UAF Response to Comment 5:
Per the EPA Control Cost Manual, Section 4 (NOx Controls) Table 1.4: Capital Cost Factors for an SNCR Application (effective at the time of the UAF BACT Analysis), the indirect capital cost is listed as 20 percent of the direct capital cost (DCC). Specifically, Table 2.5 lists general facilities as 5 percent of the DCC, engineering and home office fees as 10 percent of the DCC, and process contingency as 5 percent of the DCC, for a total of 20 percent. Please note that UAF addressed similar questions in the December 21, 2017 response to EPA Region 10 and ADEC comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.

UAF was conservative in the EU 113 SNCR cost analysis, using indirect capital costs at 18 percent of the direct capital costs. This ratio is consistent with the ExxonMobil Point Thomson Production Facility BACT analysis for SCR systems on combustion turbines, which used vendor data for indirect capital costs and not the EPA Control Cost Manual capital cost factors. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that the use of a recent ADEC-approved estimate ratio for determining indirect costs is sufficient, and that further documentation is not necessary.

6. GE Boiler: SCR – Please revise the cost analysis submitted using the EPA updated cost manual chapter pertaining to SCR. Documentation must be provided for the following cited information:
   a. "Cost of startup spares indicated as a percentage of equipment cost per similar project."

      UAF Response to Comment 6a:
      The cost of startup spares was estimated as a percentage of equipment cost in a similar project. The UAF consultant has indicated that the project was prepared for a confidential client. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that the cost for startup spare equipment estimated at 0.50 percent of total equipment costs is reasonable, and that further documentation is not necessary.

   b. Fab Site Vendor "days based on similar project".

      UAF Response to Comment 6b:
      The fabrication site vendor representative fees were assumed to be comparable to those fees from a similar project. The UAF consultant has indicated that the project was prepared for a confidential client. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI

provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that these vendor fees are reasonable, and that further documentation is not necessary.

c. Quote Vendor "days based on similar project".

UAF Response to Comment 6c:
The quote vendor representative fees were assumed to be comparable to those fees from a similar project. The UAF consultant has indicated that the project was prepared for a confidential client. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that these vendor fees are reasonable, and that further documentation is not necessary.

d. Indirect capital costs "18% was used in similar SCR BACT analysis for smaller CTs."

UAF Response to Comment 6d:
Per the EPA Control Cost Manual, Section 4 (NO_x Controls) Table 1.4: Capital Cost Factors for an SNCR Application (effective at the time of the UAF BACT Analysis), the indirect capital cost is listed as 20 percent of the DCC. Specifically, Table 2.5 lists general facilities as 5 percent of the DCC, engineering and home office fees at 10 percent of the DCC, and process contingency as 5 percent of the DCC, for a total of 20 percent. Please note that UAF addressed similar questions in the December 21, 2017 response to EPA Region 10 and ADEC comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.

UAF was conservative in the EU 112 SCR cost analysis, using indirect capital costs at 18 percent of the direct capital costs. This ratio is consistent with the ExxonMobil Point Thomson Production Facility BACT analysis for SCR systems on combustion turbines, which used vendor data for indirect capital costs and not the EPA Control Cost Manual capital cost factors. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that the use of a recent ADEC-approved estimate ratio for determining indirect costs is sufficient, and that further documentation is not necessary.

e. "Replacement labor based on similar project."

UAF Response to Comment 6e:
The catalyst replacement labor hours were assumed to be comparable to those labor hours determined in a similar project. The UAF consultant has indicated that the project was prepared for a confidential client. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that the labor

hour estimate is appropriate, and that further documentation is not necessary.

I. "Labor cost based on similar project."

UAF Response to Comment 6f:
The catalyst replacement labor rate was assumed to be comparable to the catalyst replacement labor rate determined in a similar project. The UAF consultant has indicated that the project was prepared for a confidential client. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. The labor rate used in the analysis is likely conservatively low because the cost is not reflective of 2018 labor rates. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes the rate is representative of labor costs, and that further documentation is not necessary.

7. EU 3 Mid-Sized Diesel Boiler: SCR
   a. Please provide the documentation for following citations in the BACT analysis.
      i. "Replacement labor based on similar project."

UAF Response to Comment 7a(i):
The catalyst replacement manhours and labor rate were assumed to be comparable to the manhours determined in a similar project. The UAF consultant has indicated that the project was prepared for a confidential client. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that the labor hour cost estimate for catalyst replacement is appropriate, and that further documentation is not necessary.

      ii. Transport cost direct to site (SCR catalyst). "Based on similar project."

UAF Response to Comment 7a(ii):
The catalyst transportation cost was assumed to be comparable to transport costs determined in a similar project. The UAF consultant has indicated that the project was prepared for a confidential client. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that the catalyst transport cost estimate is appropriate, and that further documentation is not necessary.

      iii. Transport cost for spent SCR catalyst. "Based on similar project."

UAF Response to Comment 7a(iii):
The transportation cost for the spent catalyst is assumed to be the same as the transportation cost for a replacement catalyst to UAF. Transportation costs are not typically dependent on the direction of travel. As a result, the analysis assumes that the cost of shipping the catalyst from the vendor to UAF will be the same as the cost of shipping the spent catalyst from UAF to the vendor.

b. No basis is provided for the SCR freight cost of $20,000.

UAF Response to Comment 7b:
UAF addressed a similar question in the December 21, 2017 response to EPA Region 10 and ADEC comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.

The $20,000 freight cost was based on the cost of freight for a smaller SCR application on the ACEP Generator Engine, EU 27. Please refer to the email from Erick Pomrenke at NC Power Systems to Lain Pacini on November 12, 2015 in Appendix B of the BACT analysis report. NC Power Systems stated that freight costs would be in the range of $9,000 to $12,000. The BACT analysis for EU 3 assumes that the SCR system for a larger emissions unit would weigh more and consequently have higher freight costs for shipment. The freight cost for an SCR system on EU 3 has been scaled up from the cost provided by NC Power Systems.

UAF believes that the estimated $20,000 freight cost is reasonable for purposes of this study-level cost analysis. UAF notes that deleting the freight cost from the analysis would result in a cost-effectiveness value that differs by less than $100 per ton of air pollutant removed. In other words, removing the freight cost from the analysis would alter the result of the analysis by less than one percent.

c. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual, provide justification for 30% contingency factor.

UAF Response to Comment 7c:
The Fuel Tech cost estimate was provided for budgetary purposes and without Fuel Tech conducting an on-site inspection. Due to the nature of the cost estimate, Fuel Tech included an accuracy range for the cost estimate. This range was +/- 20 percent for equipment capital costs and +/- 30 percent for installation costs. The Fuel Tech cost estimate values used in the BACT analysis were as quoted and did not include any additional markup or changes. In other words, the Fuel Tech cost estimate values as used in the BACT analysis were not adjusted to incorporate the cost estimate accuracy range. Please note that UAF addressed similar questions in the December 21, 2017 response to EPA Region 10 and ADEC comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.

Consistent with the EPA Control Cost Manual, a 30 percent contingency factor was applied in calculating the total capital investment. Because the cost estimate accuracy range was not included in the BACT analysis, only a single 30 percent contingency factor was used in the BACT analysis.

8. EU 8 Large Diesel Fired Engine: DPF and SCR – The BACT analysis identifies back pressure as a potential technical challenge of installing a DPF to a large diesel engine such as EU 8, please provide a technical analysis basis for this statement.

UAF Response to Comment 8.
UAF addressed a similar question in the December 21, 2017 response to EPA Region 10 and ADEC comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.

Engine exhaust back pressure is the exhaust gas pressure that is provided by the engine to overcome the resistance of the exhaust system in order to discharge the exhaust into the atmosphere. Installing a diesel particulate filter (DPF) increases the exhaust back pressure. To compensate for the increase in back pressure, the engine must compress the exhaust gases to a higher pressure which involves additional mechanical work. Maximum allowable engine exhaust back pressure is inversely related to engine size. The larger the engine is, the lower the allowable exhaust back pressure can be.

Because of the very large engine capacity of EU 8, (13,266 hp), the back pressure allowed by the engine manufacturer is very low. The reason for limiting the allowable back pressure in large engines is caused by the technical challenges that result from increased back pressure. These challenges include additional mechanical work and/or less energy extracted by the exhaust system which can adversely affect intake manifold boost pressure, an increase in fuel consumption, an increase in NOx, PM, and CO emissions, and the overheating of exhaust valves.

DPFs are not commercially available for large capacity engines because the back pressure that would be created as a result of installing a DPF would exceed the maximum allowable back pressure specified by the engine manufacturer. Exceeding the maximum allowable back pressure would not allow the engine to operate as manufactured.

9. SO2 Control Device: Circulating Dry Scrubber – Please include CDS in the analysis for SO_2 emission controls. It is required that all control devices are evaluated for BACT.

UAF Response to Comment 9.
The CFB boiler design includes integrated dry scrubbing control technology. The CFB boiler incorporates dry scrubbing technology by way of the limestone injection system that is inherent to the CFB design. The RACT/BACT/LAER Clearinghouse (RBLC) database does not list any applications of CDS used with CFB boilers. The RBLC lists only one industrial coal-fired boiler which uses CDS. That boiler is a pulverized coal (PC) boiler with a capacity of approximately 20

6mm larger than EU 113. As a result, CDS is not demonstrated in practice for CFB boilers and does not meet the criteria of an available control technology. Developing a detailed analysis to support this conclusion is not necessary.

With respect to the other boilers at UAF (EUs 3, 4, and 19 through 21), it is inherently obvious that firing ultra-low sulfur diesel (ULSD) fuel would reduce SO_2 emissions to a greater extent and would be significantly less expensive than adding post-combustion controls.

10. Control Technology Availability – Documentation from multiple control technology vendors must be provided in order to eliminate a control technology based on unavailability. Please provide additional information regarding the lack of availability for control technologies eliminated on this basis. This additional information should not be provided from the EU's manufacturer.

UAF Response to Comment 10:
Providing the requested documentation is not necessary because the unavailability of the cited emission control technologies is well established through databases such as the RACT/BACT/LAER Clearinghouse. Obtaining negative declarations of equipment availability from control technology vendors is not necessary because the UAF emissions unit manufacturers and engineers are experts who are well-versed in the available emission control technologies. As a result, UAF believes that the previously provided rationale, including any information from emissions unit manufacturers, is adequate to support the determinations that certain emission control technologies are unavailable.

11. Retrofitting – Please provide additional information regarding technologies eliminated due to space constraints and/or complications. Detailed information must be provided in support of eliminating a control technology based on space requirements. Additionally, documentation regarding any inclusion of retrofitting cost must be provided. Please provide site-specific quotes for retrofitting requirements.

UAF Response to Comment 11:
The recent construction of EU 113, including the building that houses that emissions unit, has expanded the footprint of the UAF power plant. The result of this larger footprint is that no space remains at the power plant site for a new building to house a selective catalytic reduction (SCR) system or any other new emission control systems at grade level. Please refer to the site plan drawings in Attachment 3. This lack of available space is self-evident based on visual inspection of the site and good engineering judgement. Developing detailed information and a detailed analysis is not needed to support this common sense conclusion.

Because of the space constraints, retrofitting requirements and costs cannot be easily defined or developed. As noted above, no space exists for installing new emissions control systems at grade. The lack of available space to accommodate emission control equipment affects not only EU 113, but EU 4 as well. Plan drawings of the building enclosing EU 4 are provided in Attachment 4. The drawings demonstrate that the building enclosure does not provide sufficient space to add an

SCR control system for EU 4, as discussed in the BACT analysis UAF submitted in January 2017. Common sense dictates that installing retrofitted equipment on existing roofs or above existing structures is prohibitively expensive because the existing structures are not designed to bear the additional weight and provide safe access to the new equipment. As a result, any retrofit design would involve prohibitively expensive modification and/or reconstruction of existing structures.

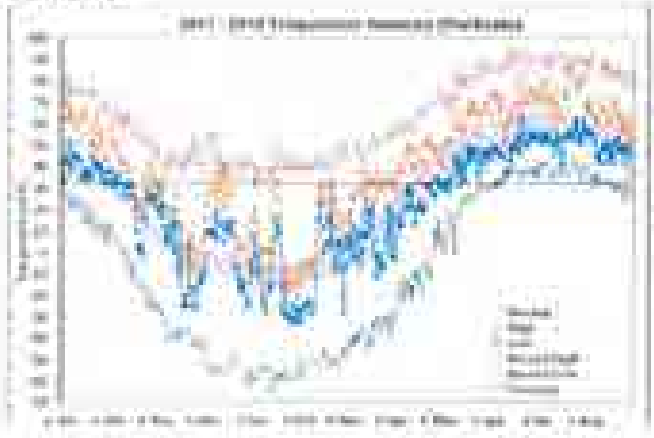
12. Request in ADEC letter dated September 13, 2018 – Specifically, ADEC requests that the University of Alaska Fairbanks review the cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the cost effectiveness calculations and indicates that the model is intended to calculate estimated total project cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent and the gross generating capacity of the plant. Please use this spreadsheet to calculate the cost effectiveness of SO_2 removal in dollars per ton and identify all assumptions and technical justifications used in the analysis.

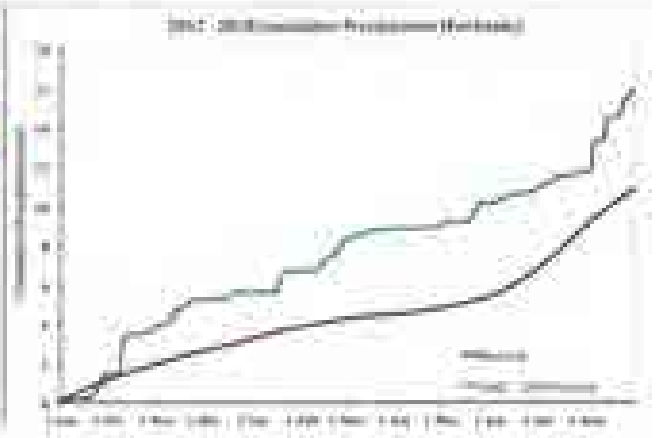
UAF Response to Comment 12:
UAF is not able to review the Sargent and Lundy (S&L) cost effectiveness spreadsheet and calculations as ADEC has requested because ADEC did not provide the S&L cost effectiveness spreadsheet to UAF for review. In May 2018, UAF submitted comments to ADEC addressing the preliminary BACT determination. Those comments included a discussion indicating that Step 4 of the preliminary SO_2 BACT determination for EU 113 did not include an economic analysis. As a result, UAF was not able to determine the methodology ADEC used to calculate the cost-effectiveness for the SO_2 emission control technologies and so was not able to provide further comment at that time. At this time, UAF does not have enough information to determine whether the S&L cost model is appropriate for any emissions units at UAF, or whether the cost model is appropriate for boilers at a heat and power plant.

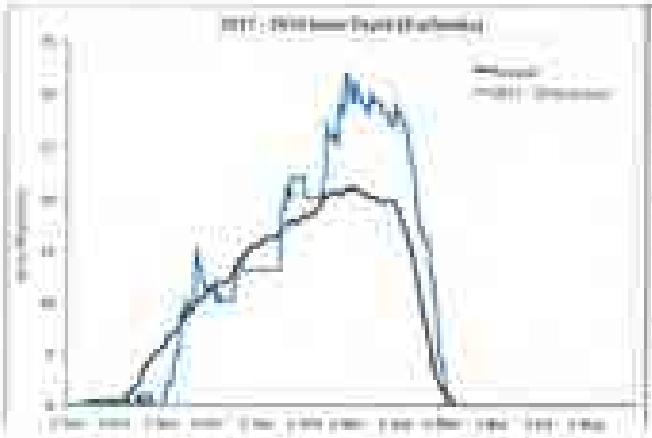
ATTACHMENT 2

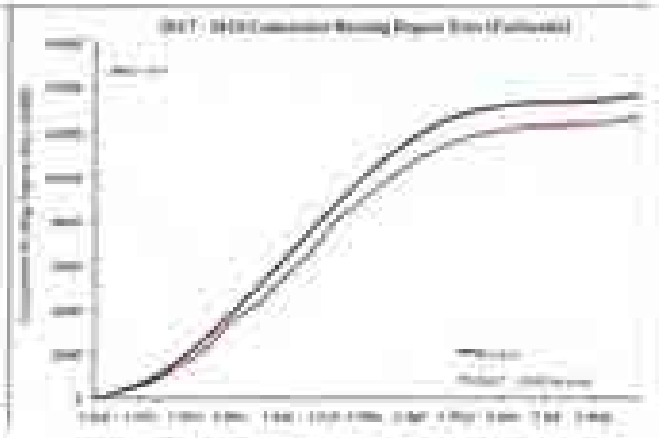


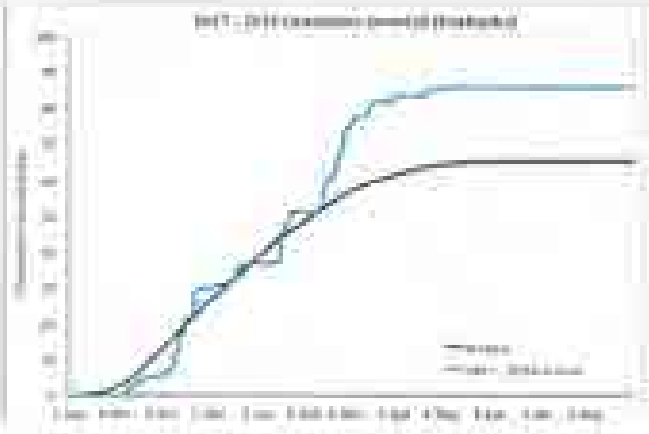
Fairbanks AP











Above Minimum	19.9	18.7	2.3	32.6	37.6	49.3	53.3	46.4	39.1	16.6	9.7	14.9
Mean	7.6	1.3	11.6	33.6	45.4	60.4	62.0	54.1	44.8	24.2	9.4	8.1
Mean Maximum	1.1	10.0	23.4	44.9	61.9	71.8	73.7	65.8	54.9	31.8	15.6	4.8
Mean Precipitation	0.55	0.42	0.22	0.31	0.66	1.37	2.19	1.88	1.10	0.83	0.67	0.44
Snowfall	10.3	9.1	4.9	0.8	0.0	0.0	0.0	0.0	1.0	10.8	19.5	12.1
CDD	0	0	0	0	1	23	31	9	0	0	0	0
HDD	2260	1648	1482	674	480	162	100	261	624	1202	1672	2141

Temperature Extremes	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Highest Daily Maximum (°F)	52	55	58	78	90	97	94	93	84	72	54	56
Year	2020	1942	1958	1946	1947	1969	1919	1934	1931	1953	1938	1944
Lowest Daily Minimum (°F)	-56	-54	-46	-23	-1	24	34	23	5	-19	-46	-52
Year	1918	1947	1920	1944	1966	2000	1974	1941	1951	1935	1946	1951
Highest Mean (°F)	18.1	15.62	27.08	42.67	53.59	65.61	66.27	62.58	52.15	31.61	22.17	7.65
Year	1991	1960	1991	1990	2005	2004	1972	1977	1955	1938	1978	1955
Lowest Mean (°F)	-33.94	-29.27	-4.65	11.06	36.61	51.43	55.5	49.77	31.84	12.19	-10.4	-26.13
Year	1971	1979	1979	2012	1964	1964	1950	1968	1992	1986	1962	1955

Precipitation Extremes	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Highest 1-Day Maximum Precipitation (in)	1.39	0.89	0.87	0.93	0.78	1.56	2.27	3.82	1.23	1.17	0.91	0.94
Year	1937	1958	1961	2002	1992	1991	2007	1967	1964	1948	1935	1936
Highest Total Precipitation (in)	4.71	2.7	2.1	2.02	3.46	3.55	6.94	6.88	3.05	3.4	2.22	2.29
Year	1937	1944	1961	2002	2004	1948	2007	1958	1983	1948	1978	1994
Lowest Total Precipitation (in)	0.01	0.01	0.02	0.11	0.24	0.19	0.55	0.26	0.12	0.06	0.05	0.04
Year	1984	1978	1943	1944	1911	1964	1956	1909	1941	1934	1926	1916

Snow Extremes	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Highest 1-Day Maximum Snow (in)	15.5	10	12.5	10.8	9.8	1.5	0	0.1	1.5	12.1	14.5	12.5
Year	1937	1966	1963	1948	1992	1971	1934	1999	1992	1949	1970	1965
Highest Total Snow (in)	60.8	47.1	30.4	25.1	14.1	1.5	0	0.1	29.4	35.2	54	50.7
Year	1937	1966	1971	1948	1992	1971	1934	1999	1992	1935	1970	1964
Lowest Total Snow (in)	0.3	0.2	0.1	0.1	0	0	0	0	0	0.7	0.3	0.4
Year	1999	1999	1985	1958	1938	1934	1934	1999	1958	2003	1963	1912

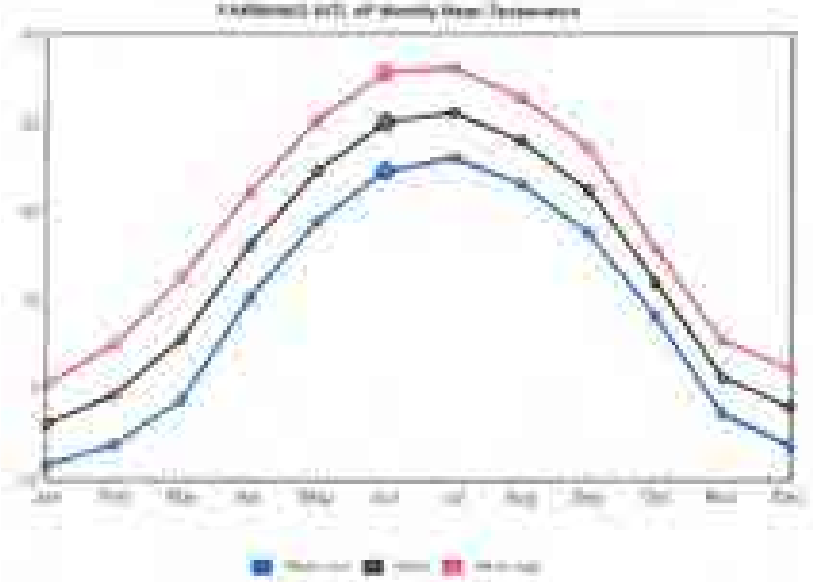
P O Box 757320 Fairbanks, Alaska 99775-7320
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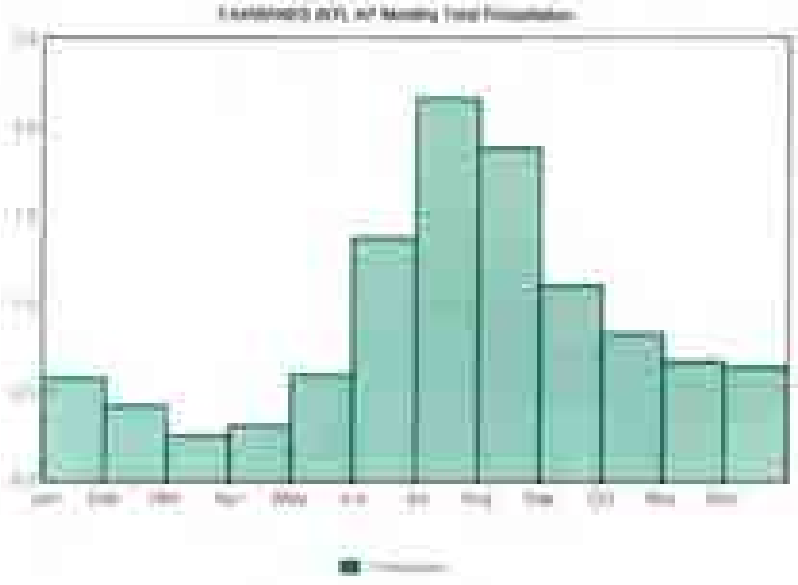


Alaska Climographs

[illegible] are the mean monthly maximum and minimum temperature and total precipitation for the period 1981 - 2010 for the first order stations in Alaska using the latest normals provided by the National Climatic Data Center. The normals products you'll find here represent averaged conditions over the most recent climate normals period (1981 - 2010).

FAIRBANKS INTL AP

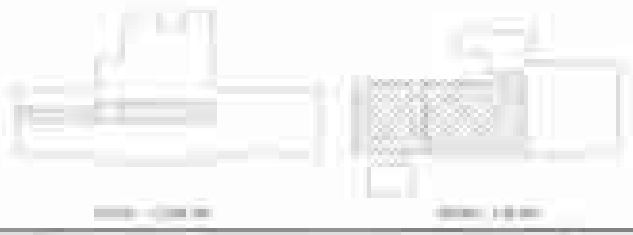




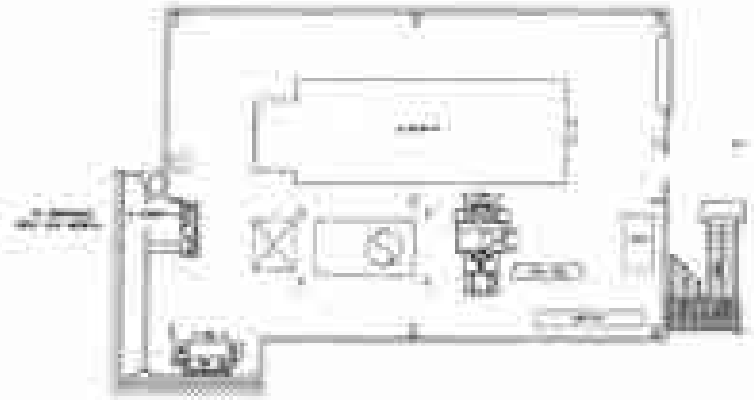
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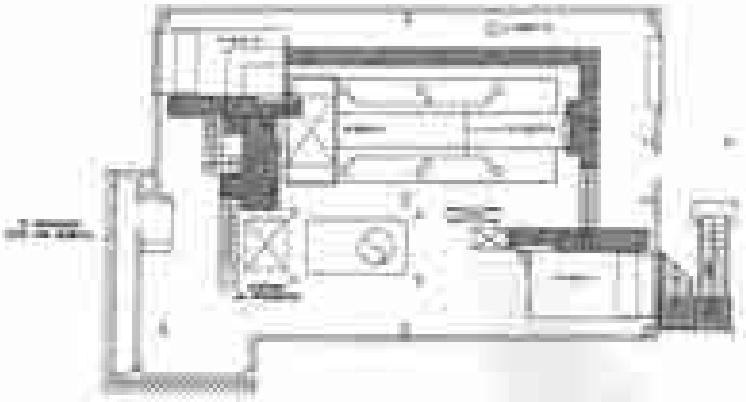
ATTACHMENT 3

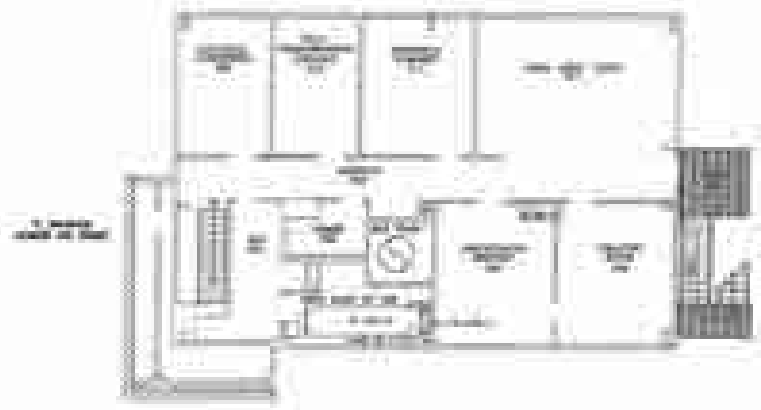




ATTACHMENT 4









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April 23, 2019

Alice Edwards, Director
Division of Air Quality
Alaska Department of Environmental Conservation
PO Box 111800
Juneau, Alaska 99811

Transmitted digitally by email to: alice.edwards@alaska.gov
cc: cindy.heil@alaska.gov; deanna.huff@alaska.gov

RE: Fairbanks Serious $PM_{2.5}$ Nonattainment Area Best Available Control Technology (BACT) Determination – Economic Infeasibility of Sulfur Dioxide (SO_2) Emission Controls

Dear Ms. Edwards,

The University of Alaska Fairbanks (UAF) is providing additional information addressing certain aspects of the Alaska Department of Environmental Conservation (ADEC) BACT determinations associated with the Fairbanks Serious Nonattainment Area for particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 microns ($PM_{2.5}$) and requesting a determination of economic infeasibility of SO_2 emission controls. UAF understands that BACT determinations are a required component of the ADEC State Implementation Plan (SIP) submittal to address the $PM_{2.5}$ nonattainment area. UAF is concerned that a requirement to implement certain air pollutant emission controls will not be financially viable, particularly in light of existing state of Alaska budget issues. Specifically, UAF is addressing the ADEC preliminary BACT determination for SO_2 emission controls on emission unit (EU) 113, a predominantly coal-fired circulating fluidized bed (CFB) boiler. The maximum heat input capacity of EU 113 is 295.6 million British thermal units per hour (MMBtu/hr). EU 113 also has the capability to combust certain types of biomass (up to 20 or 25 percent of total heat input).

The ADEC preliminary BACT determination, dated March 22, 2018, presents the preliminary finding that BACT for SO_2 emissions from EU 113 would consist of the following requirements:

1) Control SO_2 emissions by operating and maintaining dry sorbent injection (DSI) and limestone injection at all times the unit is in operation.
2) The SO_2 emission rate shall not exceed 0.05 pounds per million British thermal unit (lb/MMBtu) averaged over a 3-hour period.
3) Burn low sulfur coal at all times that the dual fuel-fired boiler is combusting coal.
4) Demonstrate initial compliance with the SO_2 emission rate by conducting a performance test.

BACT is determined, in part, through a cost effectiveness analysis. ADEC prepared an analysis to determine the cost effectiveness of SO_2 controls deemed technically feasible for EU 113, including DSI. The ADEC analysis in Table 5-3 of the preliminary BACT determination presents a total capital cost of $4,394,193, total annualized costs of $2,246,238 per year, and a cost effectiveness of $7,536 per ton of SO_2 emissions removed. A capital recovery factor of 0.1098, calculated with 7 percent interest rate over

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a 15-year equipment life, was used to annualize costs. The cost effectiveness value is calculated by dividing the total annualized cost by the tons per year of air pollutant removed by the control device. In this case, DSI is estimated to remove up to 194 tons per year of SO_2. Contrary to the cost effectiveness figure of $7,538 per ton of SO_2 emissions removed presented in Table 5-3, the cost effectiveness for DSI based on the ADEC total annualized cost of $2,246,238 and the removal of 194 tons per year of SO_2 is actually $11,578 per ton of SO_2 emissions removed.

The cost effectiveness value of $11,578 per ton of SO_2 emissions removed likely *underestimates* the actual cost. The ADEC preliminary BACT determination implies that installing DSI on EU 113 to control SO_2 emissions would not involve significant retrofit costs. UAF disagrees with this premise and provided comments addressing this issue in a letter to ADEC dated May 23, 2018. The DSI calculations used in the "UAF SO2 Economic Analyses ADEC.xlsx" spreadsheet assume that the model is appropriate to apply to EU 113 even though EU 113 is a combined heat and power boiler and is not primarily used for electric power generation. The calculations assume that Trona would be used as the sorbent in the DSI system, when sodium bicarbonate or hydrated lime are much more likely sorbent options. The DSI cost analysis was originally developed by Sargent & Lundy (S&L) to evaluate cost and emissions impacts. The documentation available on the use of this cost model does not include information necessary to ensure that the calculations are properly applied to a specific situation, including

a. Types of plants to which the model is applicable (utility power generation, combined heat and power (CHP), cogeneration, other);
b. Applicable size range;
c. Equipment included in the Total Purchased Cost (TPC) calculation;
d. On-site bulk storage capacity;
e. A basis for selecting a "Retrofit factor" other than "1.0"; and
f. Data and other information used to develop and support the equations used in the spreadsheet.

Additionally, UAF has reached out to Stanley Consultants (the primary Engineering firm for the boiler replacement project) and they have advised UAF that since the new boiler design already incorporates control of SO_2 with the direct feed of limestone into the combustion chamber, additional control of SO_2 by injection of sorbent into the flue gas is unnecessary and would involve a costly retrofit of ductwork. Stanley contacted B&W (the supplier of the new boiler) on the issue and they have provided the following specific concerns with respect to DSI installation at EU 113:

a. A switch from hydrated lime to sodium bicarbonate is necessary to achieve reasonable effectiveness
b. The existing ductwork is not long enough to provide the recommended 2-3 seconds of residence time before the baghouse.
c. The lack of residence time will significantly degrade the performance of the DSI system. When considered along with the relatively low concentrations of sulfur in the flue gas, the best performance that can be expected is somewhere between 30 percent and 50 percent capture at normal operating loads without unreasonable injection rates (>5X the norm).
d. Also, given the constraints identified above, the normal ratio of sorbent to sulfur would not be sufficient to achieve the stated capture efficiencies. It is likely that a significantly higher ratio (more sorbent per pound of sulfur) will be required.
e. It may not be possible to operate the DSI system at lower loads due to a lack of flue gas temperature at the injection point.
f. There are no other possible injection points. The only way to increase the residence time is to modify the flue gas duct (at considerable expense)

g. At the sorbent injection rates that would be required to achieve the capture rates noted above, there is a potential for significant amounts of NO2 to be formed as a result of the chemical reaction which may form a brown plume and cause visual opacity issues[1].

B&W indicates that UAF *could* install a DSI system in the existing ductwork that would achieve some reduction in sulfur pollutants. That being said, the system would not be capable of the pollutant reductions typically associated with a new DSI system. Further, the injection of significant quantities of sorbent would likely result in the generation of unacceptable levels of NOx. It is theoretically possible that the flue gas duct could be modified to optimize the performance of a new DSI system, but these modifications would be extremely difficult and expensive to make. There was no consideration for a secondary emissions control system for SO2 when the facility was originally designed. As such the boiler and the baghouse are in close proximity to each other and the flue gas duct that connects them is surrounded by essential plant equipment, structural steel, and plant utilities.

The preamble to the Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements; Final Rule dated August 24, 2016 includes guidance on preparing a Best Available Control Measures (BACM)/BACT determination in support of a serious $PM_{2.5}$ nonattainment area SIP. Specifically, determining whether an available control technology is economically feasible is addressed on page 58085 in volume 81 of the Federal Register. This section states

"…if a source contends that a source-specific control level should not be established because the source cannot afford the control measure or technology that is demonstrated to be economically feasible for purposes of BACM for other sources in its source category, the source should make its claim known to the state and support the claim with information regarding the impact of imposing the identified control measure or technology on the following financial indicators, to the extent applicable:

1. *Fixed and variable production costs ($/unit);*
2. *Product supply and demand elasticity;*
3. *Product prices (cost absorption vs. cost pass-through);*
4. *Expected costs incurred by competitors;*
5. *Company profits;*
6. *Employment costs;*
7. *Other costs (e.g. for BACM implemented by public sector entities)."*

Regardless of the exact cost, implementing DSI as SO_2 emissions controls on EU 113 is not financially possible for UAF. UAF is a public institution and an entity of the State of Alaska. On February 13, 2019 Governor Mike Dunleavy released his budget proposal for 2020. The University of Alaska (UA) is facing a proposed budget cut of $134 million, or 41 percent of the state's funding of $327 million, reducing the university's general fund support to $193 million. The cut is on top of state funding cuts that have occurred for four out of the last five years, resulting in program reductions and the loss of more than 1,200 faculty and staff. Under the Governor's spending plan, if his proposed cut is sustained by the legislature, it would be the largest year-over-year reduction in the university's history and would take UA back to 2002 funding levels. These cuts substantially impact UA and harm Alaska's ability to grow the highly trained workforce necessary to be economically competitive with other states.

The new UAF on-campus Combined Heat and Power Plant (CHPP) is an efficient and clean approach to generating electric power and heat from a single fuel source. At the UAF CHPP, fuel is burned to create

[1] August 2014 B&W Technical Paper "DSI Impacts on Visual Opacity"

steam, which both heats and cools campus and spins turbines to create electricity. Instead of purchasing electricity from the distribution grid and burning fuel in our on-site boilers to produce heat, UAF can use combined heat and power to provide both products as part of one combustion process.

If DSI were to be imposed as BACT for SO_2 emissions on EU 113, the expected impacts to the UAF financial indicators are as follows: (All costs from the 2017 UAF BACT Analysis adjusted for inflation from 2016 to 2019 dollars[2])

Capital Cost

UAF estimated in the January 2017 BACT analysis a total capital cost to install DSI control technology at EU ID 113 of $2,687,100.

Fixed and variable production costs

In the January 2017 UAF BACT Analysis, UAF estimated the total annualized cost for DSI control technology at $1,799,336 (not including labor and maintenance) with a cost effectiveness of $9,266 per ton. In the March 2018 ADEC BACT Determination, ADEC estimated the total annualized cost to be $2,246,238 with a cost effectiveness of $7,536 per ton. However, the true cost effectiveness based on the ADEC total annualized cost and the removal of 194 tons per year of SO_2 is at least $11,578 per ton of SO_2 removed as discussed above.

EU 113 is in the commissioning phase and has not yet operated at the maximum design production rate at steady state that would allow meaningful fixed and variable production cost ratios ($/kW or $/klb steam) to be calculated.

Cost Contributor	**Annualized Cost**
Production costs ($/kW or $/1,000 lb steam) *without* DSI	Not known
Production costs ($/kW or $/1,000 lb steam) *including* DSI	Not known
DSI Sorbent (sodium bicarbonate or hydrated lime)	$919,800[3]
DSI Electrical	$315,360[4]
DSI incremental ash disposal (at FNSB)	$150,000[5]
Labor for handling limestone and additional ash	$15,500[6]
Potentially voiding construction warranties	Not known

While the actual production costs of the new EU 113 boiler are not yet known, the following are the 2019 operating costs for the current UAF power plant[7]:

Operation	**Cost**
Electric	$0.203 per kilowatt hour
F&A	37.2%
Sewer	$7.00 per 1000 gallons
Steam	$15.47 per 1000 lb
Water	$7.10 per 1000 gallons

[2] 6 percent inflation adjustment 2016 to 2019 dollars per USInflationCalculator.com
[3] UAF BACT Analysis, January 2017, Table 5-7
[4] UAF BACT Analysis, January 2017, Table 5-7
[5] From estimated sorbent use and disposal cost at FNSB Solid Waste facility
[6] Estimated labor cost derived from estimated hours by UAF Director of Utilities 416 hours/yr @ $37.18/hr
[7] Data provided by the UAF Director of Utilities

Product supply and demand elasticity
Product supply and demand elasticity is not an applicable parameter because the steam heat and electricity generated through the use of EU 113 are not sold.

Product prices (cost absorption vs. cost pass-through)
Product price is not an applicable parameter because the steam heat and electricity generated through the use of EU 113 are not sold.

Expected costs incurred by competitors
Expected competitor costs is not an applicable parameter because the steam heat and electricity generated through the use of EU 113 are not sold. The UAF CHPP is not competing in the open or semi-open market.

Company profits
Company profits is not an applicable parameter because UAF is a State of Alaska facility, not a for-profit company.

Employment costs
UAF has requested and has not yet been provided the ADEC calculations for the economic analysis of SO_2 controls as discussed above.

Other costs (e.g. for BACM implemented by public sector entities)
UAF is a state institution with a budget that is determined by the Legislature. Spending funding on the DSI would cause funds to be diverted from the educational and research mission of the University. Impacts from the lack of funds include fewer staff to provide support services (grounds, maintenance, transportation, human resources, payroll, risk management, safety, fire and police, procurement), reduction in degree programs, further deferred maintenance which will cause deteriation of facilities and roads, inability to replace defunct equipment, and other impacts. The cost in dollars would be the amount of money that would be diverted for operations and maintenance of the DSI annually, plus the cost of construction of the plant and the interest payable on any bonds – the annualized cost of $2,246,238.

Other factors
It is unlikely that the incremental reduction of SO_2 emissions from EU ID 113 with the DSI system installed (compared to air quality permit limits) would significantly reduce $PM_{2.5}$ concentrations in the FNSB serious nonattainment area because:

- The stack height of EU 113 is 210 feet.
- The UAF CHPP is located towards the west end of Fairbanks of the serious nonattainment area. Flow through the airshed is comparable to flow through the local watershed (roughly east to west), therefore with normal conditions in place, impacts to the non-attainment area should be minimal.

DSI technology requires the addition of limestone, lime, or sodium bicarbonate to the boiler flue gas post-combustion prior to the baghouse. Any unreacted sorbent could alter the physical properties of the coal ash, including the leachability of metals. With an estimated quantity of 1314 tons per year of sorbent used in the DSI process at UAF, the amount of waste material captured in the baghouse will increase significantly. UAF could face the added significant cost of disposal of an increased volume of coal ash with increased hazardous properties if UAF is compelled to install DSI technology at EU 113.

UAF will commit to use of ULSD on its existing permitted fuel burning equipment that is not currently required to use this type of fuel, but understands that this will be a requirements in the serious SIP. However, any additional pollution control equipment added to any of our units will be an additional hardship to the University and its mission. Please consider this request for economic and technological infeasibility of installation of additional pollution control equipment on our permitted units. UAF will commit to completing additional source testing for SO_2 to substantiate the reduction in sulfur due to elimination of the existing coal-fired boilers and the use of the new circulated fluidized bed boiler. UAF will complete additional SO_2 source testing within 6 months after initial start-up.[8] Also, once the facility is operational, EU IDs 3 and 4 will reduce their usage dramatically which will also lower the sulfur emissions from UAF.

If you have any questions, please contact Russ Steiger at 907-474-5812 or rhsteiger@alaska.edu or Frances Isgrigg at 907-474-5487 or fisgrigg@alaska.edu.

Sincerely,



Julie Queen
Interim Vice Chancellor for Administrative Services
University of Alaska Fairbanks

[8] Initial Startup: The first time that steam is produced by the boiler and used to produce heat and/or drive the turbine(s) to produce electricity – per 1979 EPA Instruction Manual for Clarification of Startup in Source Categories Affected by New Source Performance Standards.

Although not explicitly stated in the definition, startup excludes firing an emissions unit for the purpose of commissioning prior to the emissions unit becoming operational. Pre-startup and startup are discussed in the 1979 EPA Instruction Manual for Clarification of Startup in Source Categories Affected by New Source Performance Standards.

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THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

DIVISION OF AIR QUALITY
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Return Receipt Requested

November 16, 2017

Naomi Knight, Environmental Officer
Golden Valley Electric Association
PO Box 71249
Fairbanks, AK 99707-1249

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum from Golden Valley Electric Association (GVEA) for the North Pole Power Plant and Zehnder Facility by December 22, 2017

Dear Ms. Knight:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that GVEA North Pole and Zehnder and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to a Serious Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measure (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as GVEA North Pole and Zehnder. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analyses are a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an email to Ms. Naomi Knight at GVEA on May 11, 2017 notifying her of the reclassification

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)
[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(4)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.
[3] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

to Serious and included a request for the BACT analysis to be completed by August 8, 2017. The BACT analyses from GVEA North Pole and Zehnder, which included emission units found in Operating Permits AQ0110TVP03 and AQ0109TVP03, were submitted by email to the Department on August 30, 2017.

ADEC and EPA reviewed the BACT analyses provided for GVEA North Pole and Zehnder Facilities and ADEC is requesting additional information to assist it in making a legally and practicably enforceable BACT determinations for the sources. Both the ADEC and EPA comments are enclosed in this letter. ADEC requests a response by December 22, 2017. If ADEC does not receive a response to this information request by this date, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facilities' infrastructure and without additional information may select a more stringent BACT for your facilities in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public review along with any precursor demonstrations and BACM analysis before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes final BACT determinations for GVEA North Pole and Zehnder, it must include the determinations in Alaska's Serious SIP that then ultimately requires approval by EPA.[3] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented prior to June 9, 2021 – 4 years after reclassification.[4]

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM) consideration. MSMs will be a required element of the state implementation plan if the State applies for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

ADEC appreciates the cooperation that we've received from GVEA. ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Denise Koch, Director
Division of Air Quality

[3] https://www.gpo.gov/fdsys/pkg/USCODE-2011-title42/html/USCODE-2011-title42-chap85-subchapI-partD-subpart4-sec7513a
[4] 40 CFR 51.1010(4)

Enclosures:

November 16, 2017	ADEC Request for Additional Information for GVEA North Pole and Zehnder BACT Analyses;
November 15, 2017	EPA GVEA BACT Analysis Review Comments
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for GVEA North Pole and Zehnder

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality
Jim Plosay, ADEC/ Air Quality
Aaron Simpson, ADEC/Air Quality
Naomi Knight/GVEA
Tim Hamlin, EPA Region 10
Dan Brown, EPA Region 10
Zach Hedgpeth, EPA Region 10

ADEC Request for Additional Information
Golden Valley Electric Association – North Pole and Zehnder Facilities
BACT Analysis Review
August 2017

November 16, 2017

Please address the following comments by providing the additional information identified by December 22, 2017. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public review. In order to provide this additional review opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public review period or based upon the new information provided in response to this information request.

This document does not represent a final BACT determination by ADEC. Please contact Aaron Simpson at aaron.simpson@alaska.gov with any questions regarding ADEC's comments.

1. Equipment Life – Page 31 of the North Pole analysis and Page 27 of the Zehnder analysis state "Because of the harsh climate, equipment in this far north location experiences more wear and tear than equipment in moderate climates. On this basis, a ten year return on the [water injection and] SCR system is assumed to be reasonable." This same assumption is made for the other control devices. ADEC identified that the EPA Air Pollution Control Cost Manual[1] uses a hypothetical example that assumes the control equipment has a useful life of ten years. However the cost analyses must use a reasonable estimate of the actual life of the control equipment for each control technology. In order to use an equipment life that is shorter than 30 years, evidence must be provided to support the claim that 10 years is a reasonable timeframe for equipment life. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as turbines.

2. BACT limits – BACT limits by definition, are numerical emission limits. However regulation allows a design, equipment, or work/operational practices if technological or economic limitations make a measurement methodology infeasible. Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for pollutant for each emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. Measures to minimize the occurrence of these periods, or to minimize emissions during these periods are control options. Combinations of steady-state control options and SSM control options can be combined to create distinct control strategies. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

[1] U.S. EPA OAQPS Air Pollution Control Cost Manual, 6th Edition [EPA/452/B-02-001]

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ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
Air Permits Program

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION
for
Golden Valley Electric Association
Zehnder Facility

Prepared by: Aaron Simpson
Supervisor: James R. Plosay
Preliminary Date: May 10, 2019

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Abbreviations/Acronyms

AAC ..... Alaska Administrative Code
AAAQS ..... Alaska Ambient Air Quality Standards
Department..... Alaska Department of Environmental Conservation
BACT ..... Best Available Control Technology
CFB……Circulating Fluidized Bed
CFR. ..... Code of Federal Regulations
Cyclones……Mechanical Separators
DFP……Diesel Particulate Filter
DLN..... Dry Low NOx
DOC……...Diesel Oxidation Catalyst
EPA ..... Environmental Protection Agency
ESP……Electrostatic Precipitator
EU ..... Emission Unit
FITR……...Fuel Injection Timing Retard
GCPs……..Good Combustion Practices
HAP ..... Hazardous Air Pollutant
ITR……Ignition Timing Retard
LEA……Low Excess Air
LNB……Low NOx Burners
MR&Rs..... Monitoring, Recording, and Reporting
NESHAPS..... National Emission Standards for Hazardous Air Pollutants
NSCR……Non-Selective Catalytic Reduction
NSPS ..... New Source Performance Standards
ORL ..... Owner Requested Limit
PSD..... Prevention of Significant Deterioration
PTE..... Potential to Emit
RICE, ICE..... Reciprocating Internal Combustion Engine, Internal Combustion Engine
SCR ..... Selective Catalytic Reduction
SIP ..... Alaska State Implementation Plan
SNCR……Selective Non-Catalytic Reduction
ULSD..... Ultra Low Sulfur Diesel

Units and Measures

gal/hr..... gallons per hour
g/kWh ..... grams per kilowatt hour
g/hp-hr ..... grams per horsepower hour
hr/day..... hours per day
hr/yr ..... hours per year
hp..... horsepower
lb/hr ..... pounds per hour
lb/MMBtu ..... pounds per million British thermal units
lb/1000 gal ..... pounds per 1,000 gallons
kW ..... kilowatts
MMBtu/hr ..... million British thermal units per hour
MMscf/hr ..... million standard cubic feet per hour
ppmv..... parts per million by volume
tpy..... tons per year

Pollutants

CO ..... Carbon Monoxide
HAP ..... Hazardous Air Pollutant
NOx ..... Oxides of Nitrogen
SO_2 ..... Sulfur Dioxide
PM-2.5 ..... Particulate Matter with an aerodynamic diameter not exceeding 2.5 microns
PM-10 ..... Particulate Matter with an aerodynamic diameter not exceeding 10 microns

1. INTRODUCTION

The Zehnder Facility (Zehnder) is an electric generating facility that combusts distillate fuel in combustion turbines to provide power to the Golden Valley Electric Association (GVEA) grid. The power plant contains two fuel oil-fired simple cycle gas combustion turbines and two diesel-fired generators (electro-motive diesels) used for emergency power and to serve as black start engines for the GVEA generation system. The primary fuel is stored in two 50,000 gallon aboveground storage tanks. Turbine startup fuel and electro-motive diesels primary fuel is stored in a 12,000 gallon above ground storage tank.

In a letter dated April 24, 2015, the Alaska Department of Environmental Conservation (Department) requested the stationary sources expected to be major stationary sources in the particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers (PM-2.5) serious nonattainment area perform a voluntary Best Available Control Technology (BACT) review in support of the state agency's required SIP submittal once the nonattainment area is re-classified as a Serious PM-2.5 nonattainment area. The designation of the area as "Serious" with regard to nonattainment of the 2006 24-hour PM-2.5 ambient air quality standards was published in Federal Register Vol. 82, No. 89, May 10, 2017, pages 21703-21706, with an effective date of June 9, 2017.[1]

This report addresses the significant emissions units (EUs) listed in the Zehnder facility's operating permit AQ0109TVP03. This report provides the Department's review of the BACT analysis for PM-2.5 and BACT analyses provided for oxides of nitrogen (NOx) and sulfur dioxide (SO_2) emissions, which are precursor pollutants that can form PM-2.5 in the atmosphere post combustion.

The following sections review GVEA's BACT analysis for the Zehnder Facility for technical accuracy and adherence to accepted engineering cost estimation practices.

2. BACT EVALUATION

A BACT analysis is an evaluation of all available control options for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts. 40 CFR 52.21(b)(12) defines BACT as a site-specific determination on a case-by-case basis. The Department's goal is to identify BACT for the permanent emission units (EUs) at the GVEA Zehnder facility that emit NOx, PM-2.5, and SO_2, establish emission limits which represent BACT, and assess the level of monitoring, recordkeeping, and reporting (MR&R) necessary to ensure GVEA applies BACT for the EUs. The Department based the BACT review on the five-step top-down approach set forth in Federal Register Volume 61, Number 142, July 23, 1996 (Environmental Protection Agency). Table A presents the EUs subject to BACT review.

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)

Table A: Emission Units Subject to BACT Review

EU ID	Description of EU	Rating/Size	Installation or Construction Date
1	Fuel Oil-Fired Regenerative Simple Cycle Gas Turbine	268 MMBtu/hr (18.4 MW)	1971
2	Fuel Oil-Fired Regenerative Simple Cycle Gas Turbine	268 MMBtu/hr (18.4 MW)	1972
3	Diesel-Fired Emergency Generator Engine	28 MMBtu/hr (2.75 MW)	1970
4	Diesel-Fired Emergency Generator Engine	28 MMBtu/hr (2.75 MW)	1970
10	Diesel-Fired Boiler	1.7 MMBtu/hr	2012
11	Diesel-Fired Boiler	1.7 MMBtu/hr	2012

Five-Step BACT Determinations

The following sections explain the steps used to determine BACT for NOx, PM-2.5, and SO_2 for the applicable equipment.

Step 1 Identify All Potentially Available Control Technologies

The Department identifies all available control options for the EU and the pollutant under consideration. This includes technologies used throughout the world or emission reductions through the application of available control techniques, changes in process design, and/or operational limitations. To assist in identifying available controls, the Department reviews available controls listed on the Reasonably Available Control Technology (RACT), BACT, and Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC). The RBLC is an EPA database where permitting agencies nationwide post imposed BACT for PSD sources. It is usually the first stop for BACT research. In addition to the RBLC search, the Department used several search engines to look for emerging and tried technologies used to control NOx, PM-2.5, and SO_2 emissions from equipment similar to those listed in Table A.

Step 2 Eliminate Technically Infeasible Control Technologies:

The Department evaluates the technical feasibility of each control technology based on source specific factors in relation to each EU subject to BACT. Based on sound documentation and demonstration, the Department eliminates control technologies deemed technically infeasible due to physical, chemical, and engineering difficulties.

Step 3 Rank the Remaining Control Technologies by Control Effectiveness

The Department ranks the remaining control technologies in order of control effectiveness with the most effective at the top.

Step 4 Evaluate the Most Effective Controls and Document the Results as Necessary

The Department reviews the detailed information in the BACT analysis about the control efficiency, emission rate, emission reduction, cost, environmental, and energy impacts for each option to decide the final level of control. The analysis must present an objective evaluation of both the beneficial and adverse energy, environmental, and economic impacts. A proposal to use the most effective option does not need to provide the detailed information for the less effective options. If cost is not an issue, a cost analysis is not required. Cost effectiveness for a control

option is defined as the total net annualized cost of control divided by the tons of pollutant removed per year. Annualized cost includes annualized equipment purchase, erection, electrical, piping, insulation, painting, site preparation, buildings, supervision, transportation, operation, maintenance, replacement parts, overhead, raw materials, utilities, engineering, start-up costs, financing costs, and other contingencies related to the control option. Sections 3, 4, and 5 present the Department's BACT Determinations for NOx, PM-2.5, and SO_2.

Step 5 Select BACT

The Department selects the most effective control option not eliminated in Step 4 as BACT for the pollutant and EU under review and lists the final BACT requirements determined for each EU in this step. A project may achieve emission reductions through the application of available technologies, changes in process design, and/or operational limitations. The Department reviewed GVEA's BACT analysis and made BACT determinations for NOx, PM-2.5, and SO_2 for the GVEA Zehnder Facility. These BACT determinations are based on the information submitted by GVEA in their analysis, information from vendors, suppliers, sub-contractors, RBLC, and an exhaustive internet search.

3. BACT DETERMINATION FOR NO_X

The NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC is planning to submit with the Serious SIP a final precursor demonstration as justification not to require NOx controls. Please see the precursor demonstration for NOx posted at http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip-development. The PM2.5 NAAQS Final SIP Requirements Rule states if the state determines through a precursor demonstration that controls for a precursor gas are not needed for attaining the standard, then the controls identified as BACT/BACM or Most Stringent Measure for the precursor gas are not required to be implemented.[2] Final approval of the precursor demonstration is at the time of the Serious SIP approval.

The GVEA Zehnder Facility has two existing 268 MMBtu/hr General Electric Frame 5 MS 5001-M simple cycle combustion gas turbines, two 28 MMBtu/hr General Motors Electro-Motive Diesel Generators, and two 1.7 MMBtu/hr Weil-Mclain diesel-fired boilers subject to BACT. The Department based its NOx assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by Golden Valley Electric Association (GVEA) for the North Pole Power Plant and Zehnder Facility, Aurora Energy, LLC (Aurora) for the Chena Power Plant, U.S. Army Corps of Engineers (US Army) for Fort Wainwright, and the University of Alaska Fairbanks (UAF) for the Fairbanks Campus Power Plant.

3.1 NOx BACT for the Fuel Oil-Fired Simple Cycle Gas Turbines

Possible NOx emission control technologies for the fuel oil-fired simple cycle turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf

under the process code 15.190, Liquid Fuel-Fired Simple Cycle Gas Turbines (> 25 MW). The search results for simple cycle gas turbines are summarized in Table 3-1.

Table 3-1. RBLC Summary of NOx Controls for Fuel Oil-Fired Simple Cycle Gas Turbines

Control Technology	Number of Determinations	Emission Limits (ppmv)
Selective Catalytic Reduction	2	7
Low NOx Burners	12	5 – 15
Good Combustion Practices	3	15

RBLC Review

A review of similar units in the RBLC indicates selective catalytic reduction, low NOx burners, and good combustion practices are the principle NOx control technologies installed on fuel oil-fired simple cycle gas turbines. The lowest NOx emission rate listed in the RLBC is 5 parts per million by volume (ppmv).

Step 1 - Identification of NOx Control Technology for the Simple Cycle Gas Turbines

From research, the Department identified the following technologies as available for control of NOx emissions from fuel oil-fired simple cycle gas turbines rated at 25 MW or more:

(a) Selective Catalytic Reduction (SCR)

SCR is a post-combustion gas treatment technique for reducing nitric oxide (NO) and nitrogen dioxide (NO_2) in the turbine exhaust stream to molecular nitrogen (N_2), water, and oxygen (O_2). In the SCR process, aqueous or anhydrous ammonia (NH_3) is injected into the flue gas upstream of a catalyst bed. The catalyst lowers the activation energy of the NOx decomposition reaction. NOx and NH_3 combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental N_2 and water. Depending on the overall NH_3-to-NOx ratio, removal efficiencies are generally 80 to 90 percent. Challenges associated with using SCR on fuel oil-fired simple cycle gas turbines include a narrow window of acceptable inlet and exhaust temperatures (500°F to 800°F), emission of NH_3 into the atmosphere (NH_3 slip) caused by non-stoichiometric reduction reaction, and disposal of depleted catalysts. The Department considers SCR a technically feasible control technology for the fuel oil-fired simple cycle gas combustion turbines.

(b) Water Injection

Water/steam injection involves the introduction of water or steam into the combustion zone. The injected fluid provides a heat sink which absorbs some of the heat of reaction, causing a lower flame temperature. The lower flame temperature results in lower thermal NOx formation. Both steam and water injections are capable of obtaining the same level of control. The process requires approximately 0.8 to 1.0 pound of water or steam per pound of fuel burned. The main technical consideration is the required purity of the water or steam, which is required to protect the equipment from dissolved solids. Obtaining water or steam of sufficient purity requires the installation of rigorous water treatment and deionization systems. Water/steam injection is a proven technology for NOx emissions reduction from turbines. However, the arctic environment presents significant challenges to water/steam injection due to cost of water treatment, freezing potential due to extreme cold ambient temperatures, and increased maintenance problems due to

accelerated wear in the hot sections of the turbines. Moreover, the vendor of the turbines does not recommend using water/steam injection to control NO_x emissions from the turbines because of the extra maintenance problems. The Department considers water/steam injection a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(c) Dry Low NOx (DLN)
Two-stage lean/lean combustors are essentially fuel-staged, premixed combustors in which each stage burns lean. The two-stage lean/lean combustor allows the turbine to operate with an extremely lean mixture while ensuring a stable flame. A small stoichiometric pilot flame ignites the premixed gas and provides flame stability. The NOx emissions associated with the high temperature pilot flame are insignificant. Low NOx emission levels are achieved by this combustor design through cooler flame temperatures associated with lean combustion and avoidance of localized "hot spots" by premixing the fuel and air. DLN is designed for natural gas-fired or dual-fuel fired units and is not effective in controlling NOx emissions from fuel oil-fired units. The Department does not consider DLN a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(d) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(e) Good Combustion Practices (GCPs)
GCPs typically include the following elements:

1. Sufficient residence time to complete combustion;
2. Providing and maintaining proper air/fuel ratio;
3. High temperatures and low oxygen levels in the primary combustion zone;
4. High enough overall excess oxygen levels to complete combustion and maximize thermal efficiency.

Combustion efficiency is dependent on the gas residence time, the combustion temperature, and the amount of mixing in the combustion zone. GCPs are accomplished primarily through combustion chamber design as it relates to residence time, combustion temperature, air-to-fuel mixing, and excess oxygen levels. The Department considers GCPs a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

Step 2 - Elimination of Technically Infeasible NOx Control Technologies for Gas Turbines
As explained in Step 1 of Section 3.1, the Department does not consider dry low NOx as technically feasible technology to control NO_x emissions from the fuel oil-fired simple cycle gas turbines.

Step 3 - Rank the Remaining NOx Control Technologies for the Simple Cycle Gas Turbines
The following control technologies have been identified and ranked for control of NOx emissions from the fuel oil-fired simple cycle gas turbines:

(a + b)	Selective Catalytic Reduction and Water Injection	(95% Control
(a)	Selective Catalytic Reduction	(90% Control)
(b)	Water Injection	(70% Control)
(g)	Good Combustion Practices	(Less than 40% Control)
(d)	Limited Operation	(0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA provided an economic analysis of the control technologies available for the fuel oil-fired simple cycle turbines to demonstrate that the use of water injection with SCR, SCR, or water injection in conjunction with limited operation is not economically feasible on these units. A summary of the analyses for EUs 1 and 2 is shown in Table 3-2:

Table 3-2. GVEA Economic Analysis for Technically Feasible NOx Controls per Turbine

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR and Water Injection	1,033	929.7	$18,729,680	$4,915,081	$5,287
SCR	1,033	878.1	$12,931,360	$2,837,279	$3,231
Water Injection	1,033	754.1	$3,710,000	$1,673,057	$2,219
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

GVEA contends that the economic analysis indicates the level of NOx reduction does not justify the use of SCR, Water Injection, or SCR and Water Injection for the fuel oil-fired simple cycle gas turbines based on the excessive cost per ton of NOx removed per year.

GVEA proposes the following as BACT for NOx emissions from the fuel oil-fired simple cycle gas turbines:

(a) NOx emissions from the operation of the fuel oil-fired simple cycle gas turbines will be controlled with good combustion practices; and

(b) NOx emissions from the fuel oil-fired simple cycle gas turbines will not exceed 0.88 lb/MMBtu over a 4-hour averaging period.

Department Evaluation of BACT for NOx Emissions from the Simple Cycle Gas Turbines

The Department revised the cost analyses provided by GVEA for the installation of SCR and Water Injection using the unrestricted potential to emit from the fuel oil-fired simple cycle turbines, a baseline emission rate of 0.88 lb NOx/MMBtu, a NOx removal efficiency of 95% for SCR and Water Injection, an interest rate of 5.5% (current bank prime interest rate), and a 20 year equipment life. A summary of the analysis is shown below:

Table 3-3. Department Economic Analysis for Technically Feasible NOx Controls per Turbine

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR and Water Injection	1,033	981.4	$18,729,680	$3,820,990	$3,894
Capital Recovery Factor = 0.0837 (5.5% interest rate for a 20 year equipment life)					

The Department's economic analysis indicates the level of NOx reduction justifies the installation of SCR and water injection for the fuel oil-fired simple cycle gas turbines located in the Serious PM-2.5 nonattainment area.

Step 5 - Selection of NOx BACT for the Simple Cycle Gas Turbines
The Department's finding is that the BACT for NOx emissions from the fuel oil-fired simple cycle gas turbines is as follows:

(a) NOx emissions from EUs 1 & 2 shall be controlled by operating and maintaining selective catalytic reduction and water injection at all times the units are in operation;

(b) NOx emissions from EUs 1 & 2 shall not exceed 0.044 lb/MMBtu averaged over a 3-hour period; and

(c) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation.

Table 3-4 lists the proposed NOx BACT determination for this facility along with those for other fuel oil-fired simple cycle turbines in the Serious PM-2.5 nonattainment area.

Table 3-4. Comparison of NOx BACT for Simple Cycle Gas Turbines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
North Pole	Two Fuel Oil-Fired Simple Cycle Gas Turbines	1,344 MMBtu/hr	0.044 – 0.070 lb/MMBtu	Selective Catalytic Reduction Water Injection
Zehnder	Two Fuel Oil-Fired Simple Cycle Gas Turbines	536 MMBtu/hr	0.044 lb/MMBtu	Selective Catalytic Reduction Water Injection

3.2 NOx BACT for the Large Diesel-Fired Engines

Possible NOx emission control technologies for large engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.100 to 17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 3-5.

Table 3-5. RBLC Summary of NOx Controls for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Selective Catalytic Reduction	3	0.5 - 0.7
Other Add-On Control	1	1.0
Federal Emission Standards	13	3.0 - 6.9
Good Combustion Practices	31	3.0 - 13.5
No Control Specified	60	2.8 - 14.1

RBLC Review
A review of similar units in the RBLC indicates selective catalytic reduction, good combustion practices, and compliance with federal emission standards are the principle NOx control technologies installed on large diesel-fired engines. The lowest NOx emission rate listed in the RBLC is 0.5 g/hp-hr.

Step 1 - Identification of NOx Control Technology for the Large Diesel-Fired Engines
From research, the Department identified the following technologies as available for control of NOx emissions from diesel-fired engines rated at 500 hp or greater:

(a) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT for the turbines and will not be repeated here. The Department considers SCR a technically feasible control technology for the large diesel-fired engines.

(b) Turbocharger and Aftercooler
Turbocharger technology involves the process of compressing intake air in a turbocharger upstream of the air/fuel injection. This process boosts the power output of the engine. The air compression increases the temperature of the intake air so an aftercooler is used to reduce the intake air temperature. Reducing the intake air temperature helps lower the peak flame temperature which reduces NOx formation in the combustion chamber. EU 3 and 4 are currently operating with a turbocharger and aftercooler. The Department considers turbocharger and aftercooler a technically feasible control technology for the large diesel-fired engines.

(c) Fuel Injection Timing Retard (FITR)
FITR reduces NOx emissions by the delay of the fuel injection in the engine from the time the compression chamber is at minimum volume to a time the compression chamber is expanding. Timing adjustments are relatively straightforward. The larger volume in the compression chamber produces a lower peak flame temperature. With the use of FITR the engine becomes less fuel efficient, particular matter emissions increase, and there is a limit with respect to the degree the timing may be retarded because an excessive timing delay can cause the engine to misfire. The timing retard is generally limited to no more than three degrees. Diesel engines may also produce more black smoke due to a decrease in exhaust temperature and incomplete combustion. FITR can achieve up to 50 percent NOx reduction. Due to the increase in particulate matter emissions resulting from FITR, this technology will not be carried forward.

(d) Ignition Timing Retard (ITR)
ITR lowers NOx emissions by moving the ignition event to later in the power stroke, after the piston has begun to move downward. Because the combustion chamber volume is not at a minimum, the peak flame temperature is not as high, which lowers combustion temperature and produces less thermal NOx. Use of ITR can cause an increase in fuel usage, an increase PM emissions, and engine misfiring. ITR can achieve between 20 to 30 percent NOx reduction. Due to the increase in particulate matter emissions resulting from ITR, this technology will not be carried forward.

(e) Federal Emission Standards
RBLC NOx determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 NSPS Subpart IIII, 40 C.F.R 63 Subpart ZZZZ, non-road engines (NREs), or EPA tier certifications. NSPS Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. The Department considers meeting the technology based New Source Performance Standards (NSPS) of Subpart IIII as a technically feasible control technology for the large diesel-fired engines.

(f) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. The Department considers limited operation a technically feasible control technology for the large diesel-fired engines.

(g) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle gas turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of NOx emissions. The Department considers GCPs a technically feasible control technology for the large diesel-fired engine.

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Large Engines
As explained in Step 1 of Section 3.2, the Department does not consider fuel injection timing retard and ignition timing retard as technically feasible technologies to control NOx emissions from the large diesel-fired engines.

Step 3 - Rank the Remaining NOx Control Technologies for the Large Diesel-Fired Engines
The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from the large diesel-fired engines.

(f)	Limited Operation	(94% Control)
(a)	Selective Catalytic Reduction	(90% Control)
(g)	Good Combustion Practices	(Less than 40% Control)
(e)	Federal Emission Standards	(Baseline)
(b)	Turbocharger and Aftercooler	(0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA proposes the following as BACT for NOx emissions from the large diesel-fired engines:

(a) NOx emissions from the operation of the diesel-fired engines shall be controlled with turbocharger and aftercooler;

(b) NOx emissions from the operation of the diesel-fired engines shall not exceed 0.024 lb/hp-hr over a 4-hour averaging period; and

(c) Limited Operation.

Department Evaluation of BACT for NOx Emissions from the Large Diesel-Fired Engines

The Department reviewed GVEA's proposal and finds that NOx emissions from the large diesel-fired engines can additionally be controlled by good combustion practices.

Step 5 - Selection of NOx BACT for the Large Diesel-Fired Engines

The Department's finding is that the BACT for NOx emissions from the large diesel-fired engines is as follows:

(a) NOx emissions from the operation of the diesel-fired engines will be controlled with turbocharger and aftercooler;

(b) Limit non-emergency operation of EUs 3 and 4 to no more than 100 hours per year each for maintenance checks and readiness testing;

(c) NOx emissions from EUs 3 and 4 shall not exceed 10.9 g/hp-hr[3] over a 3-hour averaging period; and

(d) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of operation.

Table 3-6 lists the proposed BACT determination for this facility along with those for other diesel-fired engines rated at more than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 3-6. Comparision of NOx BACT for Large Diesel-Fired Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	8 Large Diesel-Fired Engines	> 500 hp	3.0 – 10.9 g/hp-hr	Limited Operation Good Combustion Practices Federal Emission Standards
UAF	Large Diesel-Fired Engine	13,266 hp	1.3 g/hp-hr	Selective Catalytic Reduction Turbocharger and Aftercooler Good Combustion Practices Limited Operation
GVEA North Pole	Large Diesel-Fired Engine	600 hp	10.9 g/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp (each)	10.9 g/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation

3.3 NOx BACT for the Diesel-Fired Boilers

Possible NOx emission control technologies for diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.220, Commercial/Institutional Size Boilers (<100 MMBtu/hr). The search results for diesel-fired engines are summarized in Table 3-7.

[3] Emission rate from AP-42 Table 3.4-1 for large stationary diesel-fired engines.

Table 3-7. RBLC Summary of NOx Control for Diesel-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Low-NOx Burner	8	0.023 - 0.14
Good Combustion Practices	1	0.01
No Control Specified	2	0.070 - 0.12

RBLC Review

A review of similar units in the RBLC indicates low-NOx burners and good combustion practices are the principle NOx control technologies installed on diesel-fired boilers. The lowest NOx emission rate listed in the RBLC is 0.01 lb/MMBtu.

Step 1 - Identification of NOx Control Technology for the Diesel-Fired Boilers

From research, the Department identified the following technologies as available for control of NOx emissions from diesel fired boilers rated at less than 100 MMBtu/hr:

(a) Low NOx Burners

Using LNBs can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature. Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 60% but under certain conditions, higher reductions are possible. Air staging or two-stage combustion, is generally described as the introduction of overfire air into the boiler or furnace. Overfire air is the injection of air above the main combustion zone. As indicated by EPA's AP-42, LNBs are applicable to tangential and wall-fired boilers of various sizes but are not applicable to other boiler types such as cyclone furnaces or stokers. The Department considers LNB a technically feasible control technology for the diesel-fired boilers.

(b) Flue Gas Recirculation (FGR)

Flue gas recirculation involves extracting a portion of the flue gas from the economizer section or air heater outlet and readmitting it to the furnace through the furnace hopper, the burner windbox, or both. This method reduces the concentration of oxygen in the combustion zone and may reduce NOx by as much as 40 to 50 percent in some boilers. Chapter 1.3-7 from AP-42 indicates that FGR can require extensive modifications to the burner and windbox and can result in possible flame instability at high FGR rates. The Department does not consider FGR a technically feasible control technology for the diesel-fired boilers.

(c) Good Combustion Practices

The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle gas turbines and will not be repeated here. The Department considers GCPs a technically feasible control technology for the mid-sized diesel fired boilers.

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Diesel-Fired Boilers
As explained in Step 1 of Section 3.3, the Department does not consider flue gas recirculation as technically feasible technologies for the diesel-fired boilers.

Step 3 - Rank the Remaining NOx Control Technologies for the Diesel-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from the diesel-fired boilers:

(a) Low NOx Burners (40% - 60% Control)
(c) Good Combustion Practices (Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA provided an economic analysis for the installation of LNB per diesel-fired boiler. A summary of the analysis is shown below:

Table 3-8. Economic Analysis for Low NOx Burners per Diesel-Fired Boiler

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
LNB	1.1	0.37	$21,820	$3,107	$8,396
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

GVEA contends that the economic analysis indicates the level of NOx reduction does not justify installing LNBs on the diesel-fired boilers based on the excessive cost per ton of NOx removal per year.

GVEA proposes the following as BACT for NOx emissions from the diesel-fired boilers:

(a) NOx emissions from the operation of the diesel fired boilers shall be controlled by good combustion practices; and

(b) NOx emissions from EU 10 and 11 shall not exceed 20 lb/1000 gallons of diesel fuel over a 4-hour averaging period.

Department Evaluation of BACT for NOx Emissions from the Diesel-Fired Boilers

The Department reviewed GVEA's proposal and finds that the two diesel-fired boilers have a combined potential to emit (PTE) of less than three tons per year (tpy) for NOx based on continuous operation of 8,760 hours per year. At three tpy, the cost effectiveness in terms of dollars per ton for add-on pollution control for these units is economically infeasible.

Step 5 - Selection of NOx BACT for the Diesel-Fired Boilers
The Department's finding is that BACT for NOx emissions from the diesel-fired boilers is as follows:

(a) NOx emissions from the diesel-fired boilers shall not exceed 0.15 lb/MMBtu[4]; and

(b) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation.

Table 3-9 lists the proposed NOx BACT determination for the facility along with those for other diesel-fired boilers rated at less than 100 MMBtu/hr in the Serious PM-2.5 nonattainment area.

Table 3-9. Comparison of NOx BACT for the Diesel-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	3 Small Diesel-Fired Boilers	< 100 MMBtu/hr	0.15 lb/MMBtu	Limited Operation
Fort Wainwright	27 Small Diesel-Fired Boilers	< 100 MMBtu/hr	0.15 lb/MMBtu	Limited Operation for Non-Emergency Use (500 hours per year each) Good Combustion Practices
GVEA Zehnder	2 Small Diesel-Fired Boilers	< 100 MMBtu/hr	0.15 lb/MMBtu	Low NOx Burners

4. BACT DETERMINATION FOR PM-2.5

The Department based its PM-2.5 assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by GVEA for the North Pole Power Plant and Zehnder Facility, Aurora for the Chena Power Plant, US Army for Fort Wainwright, and UAF for the Combined Heat and Power Plant.

4.1 PM-2.5 BACT for the Fuel Oil-Fired Simple Cycle Gas Turbines (EUs 1 and 2)

Possible PM-2.5 emission control technologies for the fuel oil-fired simple cycle gas turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.190, Simple Cycle Gas Turbines (> 25 MW) The search results for simple cycle gas turbines are summarized in Table 4-1.

Table 4-1. RBLC Summary of PM-2.5 Control for Simple Cycle Gas Turbines

Control Technology	Number of Determinations	Emission Limits
Good Combustion Practices	25	0.0038 – 0.0076 lb/MMBtu
Clean Fuels	12	5 – 14 lb/hr

RBLC Review

A review of similar units in the RBLC indicates restrictions on fuel sulfur contents and good combustion practices are the principle PM control technologies installed on simple cycle gas turbines. The lowest PM-2.5 emission rate listed in the RBLC is 0.0038 lb/MMBtu.

Step 1 - Identification of PM-2.5 Control Technology for the Simple Cycle Gas Turbines

From research, the Department identified the following technologies as available for control of PM-2.5 emissions from fuel oil-fired simple cycle gas turbines:

[4] Emission rate from AP-42 Table 1.3-1 for boilers smaller than 100 MMBtu/hr (20 lb/1,000 gallons of diesel) and converted to lb/MMBtu assuming 0.137 MMBtu/gal diesel (AP-42).

(a) Low Sulfur Fuel
Low sulfur fuel has been known to reduce particulate matter emissions. PM-2.5 emission rates for low sulfur fuel are not available and therefore a BACT emissions rate cannot be set for low sulfur fuel. The Department does not consider low sulfur fuel a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(b) Low Ash Fuel
Residual fuels and crude oil are known to contain ash forming components, while refined fuels are low ash. Fuels containing ash can cause excessive wear to equipment and foul combustion components. EUs 1 and 2 are fired exclusively on distillate fuel which is a form of refined fuel, and potential PM-2.5 emissions are based on emission factors for distillate fuel. The Department considers low ash fuel a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(c) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. Due to EUs 1 and 2 currently operating under limits, the Department considers limited operation as a feasible control technology for the fuel oil-fired simple cycle gas turbines.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle gas turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of PM. The Department considers GCPs a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

Step 2 - Eliminate Technically Infeasible PM-2.5 Controls for the Simple Cycle Gas Turbines
As explained in Step 1 of Section 4.1, the Department does not consider low sulfur fuel as technically feasible technology to control PM-2.5 emissions from the fuel oil-fired simple cycle gas turbines.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Simple Cycle Gas Turbines
The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 emissions from the fuel oil-fired simple cycle gas turbines:

(d)	Good Combustion Practices	(Less than 40% Control)
(b)	Low Ash Fuel	(0% Control)
(c)	Limited Operation	(0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA proposes the following as BACT for PM-2.5 emissions from the fuel oil-fired simple cycle gas turbines:

(a) PM-2.5 emissions from EUs 1 and 2 shall not exceed 0.012 lb/MMBtu over a 4-hour averaging period; and

(b) Maintaining good combustion practices.

Step 5 - Selection of PM-2.5 BACT for the Simple Cycle Gas Turbines
The Department's finding is that BACT for PM-2.5 emissions from the fuel oil-fired simple cycle gas turbines is as follows:

(a) PM-2.5 emissions from EUs 1 and 2 shall be controlled by combusting only low ash fuel;

(b) Maintain good combustion practices at all times of operation by following the manufacturer's operation and maintenance procedures; and

(c) PM-2.5 emissions from EUs 1 & 2 shall not exceed 0.012 lb/MMBtu[5] over a 3-hour averaging period.

Table 4-2 lists the proposed PM-2.5 BACT determination for this facility along with those for other fuel oil-fired simple cycle gas turbines located in the Serious PM-2.5 nonattainment area.

Table 4-2. Comparison of PM-2.5 BACT for Simple Cycle Gas Turbines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
GVEA – North Pole	Two Fuel Oil-Fired Simple Cycle Gas Turbines	1,344 MMBtu/hr	0.012 lb/MMBtu[5] (3-hour averaging period)	Good Combustion Practices
GVEA – Zehnder	Two Fuel Oil-Fired Simple Cycle Gas Turbines	536 MMBtu/hr	0.012 lb/MMBtu[5] (3-hour averaging period)	Good Combustion Practices

4.2 PM-2.5 BACT for the Large Diesel Fired Engines

Possible PM-2.5 emission control technologies for large engine was obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110-17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 4-3.

Table 4-3. RBLC Summary of PM-2.5 Control for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Federal Emission Standards	12	0.03 – 0.02
Good Combustion Practices	28	0.03 – 0.24
Limited Operation	11	0.04 – 0.17
Low Sulfur Fuel	14	0.15 – 0.17
No Control Specified	14	0.02 – 0.15

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices, compliance with the federal emission standards, low ash/sulfur diesel, and limited operation are the principle PM-2.5 control technologies installed on large diesel-fired engines. The lowest PM-2.5 emission rate in the RBLC is 0.02 g/hp-hr.

[5] Table 3.1-2a of US EPA's AP-42 Emission Factors. https://www3.epa.gov/ttnchie1/ap42/ch03/final/c03s01.pdf

Step 1 - Identification of PM-2.5 Control Technology for the Large Diesel-Fired Engines
From research, the Department identified the following technologies as available for controls of PM-2.5 emissions from diesel fired engines rated at 500 hp or greater:

(a) Diesel Particulate Filter (DPF)
DPFs are a control technology that is designed to physically filter particulate matter from the exhaust stream. Several designs exist which require cleaning and replacement of the filter media after soot has become caked onto the filter media. Regenerative filter designs are also available that burn the soot on a regular basis to regenerate the filter media. DPF can reduce PM-2.5 emissions by 85%. The Department considers DPF a technically feasible control technology for the large diesel-fired engines.

(b) Diesel Oxidation Catalyst (DOC)
DOC can reportedly reduce PM-2.5 emissions by 30% and PM emissions by 50%. A DOC is a form of "bolt on" technology that uses a chemical process to reduce pollutants in the diesel exhaust into decreased concentrations. They replace mufflers on vehicles, and require no modifications. More specifically, this is a honeycomb type structure that has a large area coated with an active catalyst layer. As CO and other gaseous hydrocarbon particles travel along the catalyst, they are oxidized thus reducing pollution. The Department considers DOC a technically feasible control technology for the large diesel-fired engines.

(c) Positive Crankcase Ventilation
Positive crankcase ventilation is the process of re-introducing the combustion air into the cylinder chamber for a second chance at combustion after the air has seeped into and collected in the crankcase during the downward stroke of the piston cycle. This process allows any unburned fuel to be subject to a second combustion opportunity. Any combustion products act as a heat sink during the second pass through the piston, which will lower the temperature of combustion and reduce the thermal NOx formation. The Department considers positive crankcase ventilation a technically feasible control technology for the large diesel-fired engines.

(d) Low Sulfur Fuel
Low sulfur fuel has been known to reduce particulate matter emissions. The Department considers low sulfur fuel as a technically feasible control technology for the large diesel-fired engine.

(e) Low Ash Diesel
Residual fuels and crude oil are known to contain ash forming components, while refined fuels are low ash. Fuels containing ash can cause excessive wear to equipment and foul engine components. The Department considers low ash diesel a technically feasible control technology for the large diesel-fired engines.

(f) Federal Emission Standards
RBLC NOx determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 NSPS Subpart IIII, 40 C.F.R 63 Subpart ZZZZ, non-road engines (NREs), or EPA tier certifications. NSPS Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or

reconstructed after July 11, 2005. The Department considers meeting the technology based New Source Performance Standards (NSPS) as a technically feasible control technology for the large diesel-fired engines.

(g) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. The Department considers limited operation as a feasible control technology for the large diesel-fired engines.

(h) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle gas turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of PM-2.5 emissions.The Department considers GCPs a technically feasible control technology for the large diesel-fired engines.

Step 2 - Eliminate Technically Infeasible PM-2.5 Control Technologies for the Large Engines
PM-2.5 emission rates for low sulfur fuel are not available and therefore a BACT emissions rate cannot be set for low sulfur fuel. Low sulfur fuel is not a technically feasible control technology.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Large Diesel-Fired Engines
The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 emissions from the large diesel-fired engines:

(g)	Limited Operation	(94% Control)
(a)	Diesel Particulate Filters	(85% Control)
(h)	Good Combustion Practices	(Less than 40% Control)
(b)	Diesel Oxidation Catalyst	(30% Control)
(e)	Low Ash Diesel	(25% Control)
(c)	Positive Crankcase Ventilation	(10% Control)
(f)	Federal Emission Standards	(Baseline)

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA proposes limited operation as BACT for PM-2.5 emissions from the large diesel-fired engines:

(a) Limit non-emergency operation of EUs 3 and 4 to no more than 500 hours per year each for maintenance checks and readiness testing; and

(b) PM-2.5 emissions from EUs 3 and 4 shall not exceed 0.1 lb/MMBtu[6] over a 4-hour averaging period.

Department Evaluation of BACT for PM-2.5 Emissions from the Large Diesel-Fired Engines
The Department reviewed GVEA's proposal finds that PM-2.5 emissions from the large diesel-fired engines can also be controlled by good combustion practices.

[6] Table 3.4-1 of US EPA's AP-42 Emission Factors (PM). https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s04.pdf

Step 5 - Selection of PM-2.5 BACT for the Large Diesel-Fired Engines
The Department's finding is that the BACT for PM-2.5 emissions from the large diesel-fired engines is as follows:

(a) Limit non-emergency operation of EUs 3 and 4 to no more than 100 hours per year each for maintenance checks and readiness testing;

(b) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation; and

(c) PM-2.5 emissions from EUs 3 and 4 shall not exceed 0.32 g/hp-hr[6] over a 3-hour averaging period.

Table 4-4 lists the proposed PM-2.5 BACT determination for the facility along with those for other diesel-fired engines rated at more than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 4-4. Comparison of PM-2.5 BACT for Large Diesel Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	Large Diesel-Fired Engine	13,266 hp	0.32 g/hp-hr	Positive Crankcase Ventilation Limited Operation
Fort Wainwright	8 Large Diesel-Fired Engines	> 500 hp	0.15 – 0.32 g/hp-hr	Limited Operation Ultra-Low Sulfur Diesel Federal Emission Standards
GVEA North Pole	Large Diesel-Fired Engine	600 hp	0.32 g/hp-hr	Positive Crankcase Ventilation Good Combustion Practices
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp (each)	0.32 g/hp-hr	Limited Operation Good Combustion Practices

4.3 PM-2.5 BACT for the Diesel Fired Boilers

Possible PM-2.5 emission control technologies for small diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.220, Commercial/Institutional Size Boilers (<100 MMBtu/hr). The search results for diesel-fired boilers are summarized in Table 4-5.

Table 4-5. RBLC Summary of PM-2.5 Control for Diesel Fired Boilers

Control Technology	Number of Determinations	Emission Limits
Good Combustion Practices	3	0.25 lb/gal
		0.1 tpy
		2.17 lb/hr

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices is the principle PM-2.5 control technology determined for small diesel-fired boilers. The lowest PM-2.5 emission rate listed in the RBLC is 0.1 tpy.

Step 1 - Identification of PM-2.5 Control Technology for the Diesel Fired Boilers
From research, the Department identified the following technologies as available for control of PM-2.5 emissions from diesel-fired boilers:

(a) Wet Scrubbers
Wet scrubbers use a scrubbing solution to remove PM/PM_{10}/$PM_{2.5}$ from exhaust gas streams. The mechanism for particulate collection is impaction and interception by water droplets. Wet scrubbers are configured as counter-flow, cross-flow, or concurrent flow, but typically employ counter-flow where the scrubbing fluid is in the opposite direction as the gas flow. Wet scrubbers have control efficiencies of 50% - 99%.[7] One advantage of wet scrubbers is that they can be effective on condensable particulate matter. A disadvantage of wet scrubbers is that they consume water and produce water and sludge. For fine particulate control, a venturi scrubber can be used, but typical loadings for such a scrubber are 0.1-50 grains/scf. The Department considers the use of wet scrubbers a technically feasible control technology for the diesel-fired boilers.

(b) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle gas turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of PM-2.5 emissions. The Department considers GCPs a technically feasible control technology for the diesel-fired boilers.

Step 2 - Eliminate Technically Infeasible PM-2.5 Control Technologies for the Diesel Fired Boilers
All identified control devices are technically feasible for the diesel-fired boilers.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Diesel Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 emissions from the diesel-fired boilers:

(a) Wet Scrubbers (50% - 99% Control)
(b) Good Combustion Practices (Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA proposes the following as BACT for PM-2.5 emissions from the diesel-fired boilers:

(a) Good Combustion Practices; and

(b) PM-2.5 emissions shall not exceed 2.13 lb/1,000 gallons[8] over a 4-hour averaging period.

Department Evaluation of BACT for PM-2.5 Emissions from Diesel-Fired Boilers

The Department reviewed GVEA's proposal and finds that the two diesel-fired boilers have a combined PTE of less than two tpy for PM-2.5 based on continuous operation of 8,760 hours per

[7] https://www3.epa.gov/ttn/catc/dir1/fcondnse.pdf
https://www3.epa.gov/ttn/catc/dir1/fiberbed.pdf
https://www3.epa.gov/ttn/catc/dir1/fventuri.pdf
[8] Tables 1.3-2 & 1.3-7 of US EPA's AP-42 Emission Factors: https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s03.pdf

year. At two tpy, the cost effectiveness in terms of dollars per ton for add-on pollution control for these units is economically infeasible.

Step 5 - Selection of PM-2.5 BACT for the Diesel-Fired Boilers

The Department's finding is that BACT for PM-2.5 emissions from the diesel-fired boilers is as follows:

(a) PM-2.5 emissions from the diesel-fired boilers shall not exceed 0.012 lb/MMBtu[9] over a 3-hour averaging period; and

(b) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation.

Table 4-6 lists the proposed PM-2.5 BACT determination for this facility along with those for other diesel-fired boilers rated at less than 100 MMBtu/hr in the Serious PM-2.5 nonattainment area.

Table 4-6. Comparison of PM-2.5 BACT for the Diesel-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	3 Small Diesel-Fired Boilers	< 100 MMBtu/hr	0.012 lb/MMbtu[9]	Limited Operation
Fort Wainwright	27 Small Diesel-Fired Boilers	< 100 MMBtu/hr	0.012 lb/MMbtu[9]	Good Combustion Practices
GVEA Zehnder	2 Small Diesel-Fired Boilers	1.7 MMBtu/hr (each)	0.012 lb/MMbtu[9]	Good Combustion Practices

5. BACT DETERMINATION FOR SO_2

The Department based its SO_2 assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by GVEA for the North Pole Power Plant and Zehnder Facility, Aurora for the Chena Power Plant, US Army for Fort Wainwright, and UAF for the Combined Heat and Power Plant.

5.1 SO_2 BACT for the Fuel Oil-Fired Simple Cycle Gas Turbines

Possible SO_2 emission control technologies for the large dual fuel fired boiler was obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.190, Liquid Fuel-Fired Simple Cycle Gas Turbines (> 25 MW). The search results for simple cycle gas turbines are summarized in Table 5-1.

Table 5-1. RBLC Summary of SO_2 Controls for Fuel Oil-Fired Simple Cycle Gas Turbines

Control Technology	Number of Determinations	Emission Limits
Ultra-Low Sulfur Diesel	7	0.0015 % S by wt.
Low Sulfur Fuel	2	0.0026 – 0.055 lb/MMBtu
Good Combustion Practices	3	0.6 lb/hr

RBLC Review

A review of similar units in the RBLC indicates that limiting the sulfur content of fuel and good combustion practices are the principle SO_2 control technologies determined as BACT for fuel

[9] Emission factor from AP-42 Table's 1.3-2 (total condensable particulate matter from No. 2 oil, 1.3 lb/1,000 gal) and 1.3-6 (PM-2.5 size-specific factor from distillate oil, 0.25 lb/1,000 gal) converted to lb/MMBtu.

oil-fired simple cycle gas turbines. The lowest SO_2 emission rate listed in the RBLC is combustion of ULSD at 0.0015 % S by wt.

Step 1 - Identification of SO_2 Control Technology for the Simple Cycle Gas Turbines
From research, the Department identified the following technologies as available for control of SO_2 emissions from fuel oil-fired simple cycle gas turbines:

(a) Ultra Low Sulfur Diesel (ULSD)
ULSD has a fuel sulfur content of 0.0015 percent sulfur by weight or less. Using ULSD would reduce SO_2 emissions because the fuel oil-fired simple cycle gas turbines are combusting standard diesel that has a sulfur content of up to 0.5 percent sulfur by weight. Switching to ULSD could reach a great than 99 percent decrease in SO_2 emissions from the fuel oil-fired simple cycle gas turbines. The Department considers ULSD a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(b) Low Sulfur Fuel
Low sulfur fuel has a fuel sulfur content of 0.05 percent sulfur by weight. Using low sulfur fuel would reduce SO_2 emissions because the fuel oil-fired simple cycle gas turbines are combusting standard diesel that has a sulfur content of up to 0.5 percent sulfur by weight. Switching to low sulfur fuel could reach a 93 percent decrease in SO_2 emissions from the fuel oil-fired simple cycle gas turbines during non-startup operation. The Department considers low sulfur diesel a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(c) Good Combustion Practices (GCPs)
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle gas turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2. The Department considers GCPs a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

Step 2 - Eliminate Technically Infeasible SO_2 Controls for the Simple Cycle Gas Turbines
All control technologies identified are technically feasible for the fuel oil-fired simple cycle gas turbines.

Step 3 - Rank Remaining SO_2 Control Technologies for the Simple Cycle Gas Turbines
The following control technologies have been identified and ranked for control of SO_2 emissions from the fuel oil-fired simple cycle turbines:

(a) Ultra Low Sulfur Diesel (99.7% Control)
(b) Low Sulfur Fuel (93% Control)
(c) Good Combustion Practices (Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA provided an economic analysis for switching the fuel combusted in the simple cycle gas turbines to ultra-low sulfur diesel (ULSD). A summary of the analysis for both of the turbines combined is shown below:

Table 5-2. GVEA Economic Analysis for Technically Feasible SO_2 Controls for Turbines

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD (0.0015 % S wt.)	580	578	$8,674,362	$8,239,935	$14,250
Low Sulfur Fuel (0.05 % S wt.)	580	522	???	???	???
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

GVEA contends that the economic analysis indicates the level of SO_2 reduction does not justify the fuel switch to ULSD in the simple cycle turbines based on the excessive cost per ton of SO_2 removed per year.

GVEA proposes the following as BACT for SO_2 emissions from the simple cycle gas turbines:

(a) SO_2 emissions from the operation of the fuel oil-fired simple cycle gas turbines will be controlled with good combustion practices; and

(b) Fuel burned in the fuel oil-fired simple cycle gas turbine will be limited to a sulfur content of 0.5 percent by weight.

Department Evaluation of BACT for SO_2 Emissions from the Simple Cycle Gas Turbines
The Department revised the cost analysis provided for the fuel switch to ULSD in the simple cycle gas turbines using the existing 580 tons of sulfur per year limit for the facility, an interest rate of 5.5% (current bank prime interest rate), a 20 year equipment life, and a fuel cost increase of $0.2668/gallon. Additionally, the Department reviewed the cost information provided by GVEA to appropriately evaluate the total capital investment of installing two new 1.5 million gallon ULSD storage tanks at GVEA's North Pole Facility. A summary of this analysis for both of the turbines combined is shown in Table 5-3:

Table 5-3. Department Economic Analysis for Technically Feasible SO_2 Controls for Turbines

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD	580	578	$8,674,362	$5,354,581	$9,260
Capital Recovery Factor = 0.0837 (5.5% interest rate for a 20 year equipment life)					

The Department's economic analysis indicates the level of SO_2 reduction justifies the use of ULSD as BACT for the fuel oil-fired simple cycle gas turbines located in the Serious PM-2.5 nonattainment area.

Step 5 - Selection of SO_2 BACT for the Simple Cycle Gas Turbines
The Department's finding is that BACT for SO_2 emissions from the fuel oil-fired simple cycle gas turbines is as follows:

(a) SO_2 emissions from EUs 1 and 2 shall be controlled by limiting the sulfur content of fuel combusted in the turbines to no more than 0.0015 percent by weight;

(b) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation; and

(c) Compliance with the proposed fuel sulfur content limit will be demonstrated with fuel shipment receipts and/or fuel test results for sulfur content.

Table 5-4 lists the proposed SO_2 BACT determination for this facility along with those for other fuel oil-fired simple cycle gas turbines located in the Serious PM-2.5 nonattainment area.

Table 5-4. Comparison of SO_2 BACT for Simple Cycle Gas Turbines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
GVEA – North Pole	Two Fuel Oil-Fired Simple Cycle Gas Turbines	1,344 MMBtu/hr	0.0015 % S wt.	ULSD
GVEA – Zehnder	Two Fuel Oil-Fired Simple Cycle Gas Turbines	536 MMBtu/hr	0.0015 % S wt.	ULSD

5.2 SO_2 BACT for the Large Diesel-Fired Engines

Possible SO_2 emission control technologies for large engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.100 to 17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 5-5.

Table 5-5. RBLC Summary Results for SO_2 Control for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Low Sulfur Diesel	27	0.005 – 0.02
Federal Emission Standards	6	0.001 – 0.005
Limited Operation	6	0.005 – 0.006
Good Combustion Practices	3	None Specified
No Control Specified	11	0.005 – 0.008

RBLC Review

A review of similar units in the RBLC indicates combustion of low sulfur fuel, limited operation, good combustion practices, and compliance with the federal emission standards are the principle SO_2 control technologies installed on large diesel-fired engines. The lowest SO_2 emission rate listed in the RBLC is 0.001 g/hp-hr.

Step 1 - Identification of SO_2 Control Technology for the Large Diesel-Fired Engines

From research, the Department identified the following technologies as available for control of SO_2 emissions from diesel fired engines rated at 500 hp or greater:

(a) Ultra Low Sulfur Diesel
The theory of ULSD was discussed in detail in the SO_2 BACT for the fuel oil-fired simple cycle gas turbines and will not be repeated here. The Department considers ULSD a technically feasible control technology for the large diesel-fired engines.

(b) Federal Emission Standards
The theory of federal emission standards was discussed in detail in the NOx BACT for the large diesel-fired engine and will not be repeated here. The Department considers meeting the technology based NSPS of Subpart IIII as a technically feasible control technology for the large diesel-fired engines.

(c) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation a technically feasible control technology for the large diesel-fired engines.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle gas turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the large diesel-fired engines.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for the Large Engines
All identified control technologies are technically feasible for the large diesel-fired engines.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Large Diesel-Fired Engines
The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from the large diesel-fired engines.

(a) Ultra-Low Sulfur Diesel (99% Control)
(c) Limited Operation (94% Control)
(d) Good Combustion Practices (Less than 40% Control)
(b) Federal Emission Standards (Baseline)

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA provided an economic analysis of the control technologies available for the large diesel-fired engine to demonstrate that the use of ULSD with limited operation is not economically feasible on these units. A summary of the analysis for EUs 3 and 4 is shown below:

Table 5-6. GVEA Economic Analysis for Technically Feasible SO_2 Controls per Engine

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD	3.71	3.70	--	$28,732	$7,768
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

GVEA contends that the economic analysis indicates the level of SO_2 reduction does not justify the use of ULSD for the large diesel-fired engines based on the excessive cost per ton of SO_2 removed per year.

GVEA proposes the following as BACT for SO_2 emissions from the diesel-fired engines:

(a) SO_2 emissions from the operation of the diesel fired engines will be controlled with good combustion practices; and

(b) Limit the sulfur content of fuel combusted in EUs 3 and 4 to no more than 0.5 percent sulfur by weight.

Department Evaluation of BACT for SO_2 Emissions from the Diesel-Fired Engines

The Department reviewed GVEA's proposal for EUs 3 and 4 and finds that ULSD is an economically feasible control technology for large diesel-fired engines located in the Serious PM-2.5 nonattainment area. The Department does not agree with some of the assumptions provided in GVEA's cost analysis that cause an overestimation of the cost effectiveness. However, since this overestimation is still cost effective, the Department did not revise the cost analysis. The Department further finds that SO_2 emissions from the large diesel-fired engines can additionally be controlled by limiting the use of the units during non-emergency operation.

Step 5 - Selection of SO_2 BACT for the Diesel Fired Engines

The Department's finding is that the BACT for SO_2 emissions from the diesel-fired engines is as follows:

(a) SO_2 emissions from EUs 3 and 4 shall be controlled limiting the sulfur content of fuel combusted in the engines to no more than 0.0015 percent by weight;

(b) Limit non-emergency operation of EUs 3 and 4 to no more than 100 hours per year each, for maintenance checks and readiness testing;

(c) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of operation; and

(d) Compliance with the proposed fuel sulfur content limit will be demonstrated with fuel shipment receipts and/or fuel test results for sulfur content.

Table 5-7 lists the proposed SO_2 BACT determination for this facility along with those for other diesel-fired engines rated at more than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 5-7. Comparison of SO_2 BACT for Large Diesel-Fired Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	8 Large Diesel-Fired Engines	> 500 hp	15 ppmw S in fuel	Limited Operation Good Combustion Practices Ultra-Low Sulfur Diesel
UAF	Large Diesel-Fired Engine	13,266 hp	15 ppmw S in fuel	Limited Operation Good Combustion Practices Ultra-Low Sulfur Diesel
GVEA North Pole	Large Diesel-Fired Engine	600 hp	500 ppmw S in fuel	Limited Operation Good Combustion Practices

Facility	Process Description	Capacity	Limitation	Control Method
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel

5.3 SO_2 BACT for the Diesel Fired Boilers

Possible SO_2 emission control technologies for small diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.220, Industrial Size Boilers (<100 MMBtu/hr). The search results for diesel-fired engines are summarized in Table 5-8.

Table 5-8. RBLC Summary of SO_2 Control for the Small Diesel-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Low Sulfur Fuel	5	0.0036 – 0.0094
Good Combustion Practices	4	0.0005
No Control Specified	5	0.0005

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and combustion of low sulfur fuel are the principle SO_2 control technologies installed on diesel-fired boilers. The lowest SO_2 emission rate listed in the RBLC is 0.0005 lb/MMBtu.

Step 1 - Identification of SO_2 Control Technology for the Diesel Fired Boilers
From research, the Department identified the following technologies as available for SO_2 control for the diesel-fired boilers:

(a) Ultra Low Sulfur Diesel
ULSD has a fuel sulfur content of 0.0015 percent sulfur by weight or less. Using ULSD would reduce SO_2 emissions because the mid-sized diesel boilers are combusting standard diesel that has a sulfur content of up to 0.5 percent sulfur by weight. Switching to ULSD could control 99 percent decrease in SO_2 emissions from the diesel fired boilers. The Department considers ULSD a technically feasible control technology for the diesel-fired boilers.

(b) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle gas turbine and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the diesel-fired boilers.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for the Diesel-Fired Boilers
All identified control technologies are technically feasible for the diesel-fired boilers.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Diesel-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from the diesel-fired boilers.

(a) Ultra Low Sulfur Diesel (99% Control)
(b) Good Combustion Practices (Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA proposes the following as BACT for SO_2 emissions from the diesel-fired boilers:

(a) Combust only ULSD.

Department Evaluation of BACT for SO_2 Emissions from Diesel-Fired Boilers
The Department reviewed GVEA's proposal and finds that SO_2 emissions from the diesel-fired boilers can additionally be controlled with good combustion practices.

Step 5 - Selection of SO_2 BACT for the Diesel-Fired Boilers
The Department's finding is that BACT for SO_2 emissions from the diesel-fired boilers is as follows:

(a) SO_2 emissions from EUs 10 and 11 shall be controlled limiting the sulfur content of fuel combusted in the turbines to no more than 0.0015 percent by weight;
(b) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation; and
(c) Compliance with the proposed fuel sulfur content limit will be demonstrated with fuel shipment receipts and/or fuel test results for sulfur content.

Table 5-9 lists the proposed SO_2 BACT determination for this facility along with those for other diesel-fired boilers rated at less than 100 MMBtu/hr in the Serious PM-2.5 nonattainment area.

Table 5-9. Comparison of SO_2 BACT for the Diesel-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Limited Operation Good Combustion Practices Ultra-Low Sulfur Diesel
	Waste Fuel-Fired Boilers		0.5 % S by weight	Good Combustion Practices
UAF	3 Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel
GVEA Zehnder	2 Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel

6. BACT DETERMINATION SUMMARY

Table 6-1. Proposed NOx BACT Limits

EU ID	Description of EU	Capacity	Proposed BACT Limit	Proposed BACT Control
1	Fuel Oil-Fired Regenerative Gas Simple Cycle Gas Turbine	268 MMBtu/hr	0.044 lb/MMBtu	Selective Cayalytic Reduction Water Injection
2	Fuel Oil-Fired Regenerative Gas Simple Cycle Gas Turbine	268 MMBtu/hr	0.044 lb/MMBtu	
3	Diesel-Fired Emergency Generator Engine	28 MMBtu/hr	10.9 g/hp-hr	Turbocharger & Aftercooler Good Combustion Practices Limited Operation (100 hours/year each, for non-emergency operation)
4	Diesel-Fired Emergency Generator Engine	28 MMBtu/hr	10.9 g/hp-hr	
10	Diesel-Fired Boiler	1.7 MMBtu/hr	0.15 lb/MMBtu	Good Combustion Practices
11	Diesel-Fired Boiler	1.7 MMBtu/hr	0.15 lb/MMBtu	

Table 6-2. Proposed PM-2.5 BACT Limits

EU ID	Description of EU	Capacity	Proposed BACT Limit	Proposed BACT Control
1	Fuel Oil-Fired Regenerative Gas Simple Cycle Gas Turbine	268 MMBtu/hr	0.012 lb/MMBtu	Low Ash Fuel Good Combustion Practices
2	Fuel Oil-Fired Regenerative Gas Simple Cycle Gas Turbine	268 MMBtu/hr	0.012 lb/MMBtu	
3	Diesel-Fired Emergency Generator Engine	28 MMBtu/hr	0.32 g/hp-hr	Good Combustion Practices Limited Operation (100 hours/year each, for non-emergency operation)
4	Diesel-Fired Emergency Generator Engine	28 MMBtu/hr	0.32 g/hp-hr	
10	Diesel-Fired Boiler	1.7 MMBtu/hr	0.012 lb/MMBtu	Good Combustion Practices
11	Diesel-Fired Boiler	1.7 MMBtu/hr	0.012 lb/MMBtu	

Table 6-3. Proposed SO_2 BACT Limits

EU ID	Description of EU	Capacity	Proposed BACT Limit	Proposed BACT Control
1	Fuel Oil-Fired Regenerative Gas Simple Cycle Gas Turbine	268 MMBtu/hr	15 ppmw S in Fuel	Ultra Low Sulfur Diesel
2	Fuel Oil-Fired Regenerative Gas Simple Cycle Gas Turbine	268 MMBtu/hr	15 ppmw S in Fuel	
3	Diesel-Fired Emergency Generator Engine	28 MMBtu/hr	15 ppmw S in Fuel	Ultra Low Sulfur Diesel Good Combustion Practices Limited Operation (100 hours/year each, for non-emergency operation)
4	Diesel-Fired Emergency Generator Engine	28 MMBtu/hr	15 ppmw S in Fuel	
10	Diesel-Fired Boiler	1.7 MMBtu/hr	15 ppmw S in Fuel	Ultra Low Sulfur Diesel Good Combustion Practices
11	Diesel-Fired Boiler	1.7 MMBtu/hr	15 ppmw S in Fuel	

3. Cost Analyses – Page 44 of the North Pole analysis indicates that EUs 1 and 2 have historically low run hours. Page 34 of the Zehnder analysis state that "GVEA believes that an economic analysis based on the actual emissions and operations of these turbines is more relevant for purposes of determining viable ways to reduce PM2.5 ambient concentrations in the Fairbanks area." However, all BACT cost effectiveness calculations must be based upon the potential to emit, and not on historic operation. Please update the cost analyses using the unrestricted potential to emit for each of the emissions units or propose operational limits (including control efficiencies associated with limited operation). Additionally, see Comments 4, 5, and 6 for additional information related to retrofit costs, baseline emissions, and factor of safety.
4. Retrofit Costs – EPA's Control Cost Manual indicates that study-level cost estimates (± 30 percent) should not include a retrofit factor greater than 30 percent, so detailed cost estimates (± 5 percent) is required for higher factors. High retrofit cost factors (50 percent or more) may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement). Provide detailed cost analyses and justification for any difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analyses.
5. Baseline Emissions – Include the baseline emissions for all emission units included in the analyses. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). NSPS and NESHAP requirements are not considered in calculating the baseline emissions. The baseline is usually the legal limit that would exist, but for the BACT determination. Baseline takes into account the effect of equipment that is part of the design of the unit (e.g., water injection and low NOx burners) because they are considered integral components to the unit's design. If the uncontrolled emission rate is 'soft,' run the cost effectiveness calculations using two or three different baselines.
6. Factor of Safety – If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.
7. Good Combustion Practices –For each emission unit type (oil fuel-fired turbines, combined cycle turbines, emergency generator engines, and boilers) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices. Include any work or operational practices that will be implemented and describe how continuous compliance with good combustion practices will be achieved.
8. Alternate Fuel – Page 96 of the North Pole analysis indicates that "the capital costs incurred to switch fuels [to ULSD] would include an estimated capital cost of $30,425,000 to install bulk fuel storage." Please provide a full evaluation of the fuel change impacts, fuel pricing, and bulk storage facility pricing. Based on the fuel supply information gathered for the BACM analysis for the Fairbanks Serious SIP, the Department is aware of more than one supplier of alternate fuels. Please make sure all supplier cost information is addressed for all emission units that are evaluating a fuel switch.
9. Cost Analysis Spreadsheets – The BACT analyses for North Pole and Zehnder Facilities include emissions, cost effectiveness, and incremental cost effectiveness calculations, but none of these calculations have been submitted in a spreadsheet format. Please submit the electronic versions of the spreadsheets used in determining the cost effectiveness for any control technology not selected as the highest level of control.

10. Confidential Documentation – The BACT analyses for North Pole and Zehnder Facilities have indicated that details related to costs were included in a separately submitted package under application for confidentiality of records. Please submit the supporting documentation so the Department can conduct a more detailed review of the analyses and calculations.
11. Control Technology Availability – For the North Pole Facility, include Flue Gas Recirculation in the review of NOx control technologies for diesel-fired boilers. Rank the control technologies by efficiency (specify % control). Select the best performing control technology as BACT or provide specific energy, environmental, and economic impacts and other costs justification for why each better performing control technology was not selected instead of good combustion practices. Provide a numerical NOx emission limit for the diesel-fired boilers or identify the work or operational practices that will be utilized to ensure compliance with proposed limits.

GVEA – North Pole and Zehnder Power Plants
BACT Analysis Review Comments
Reports dated August 2017 – GVEA

Zach Hedgpeth, PE
EPA Region 10 – Seattle
November 15, 2017

Note: These comments represent a partial review of the BACT analyses for the GVEA North Pole and Zehnder facilities, since none of the emission calculations or cost analysis calculations have been submitted in spreadsheet format. Also, certain documents forming the basis for costs used in the analyses have not been submitted due to confidentiality concerns. EPA Region 10 will conduct a more detailed review of the analysis and calculations following submittal of this information.

1. Equipment Life – Page 31 of the North Pole analysis[1] states "a standardized ten year return on investment at seven percent interest rate is assumed". This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in this far north location experiences more wear and tear than equipment in moderate climates". The analysis includes no further information to support the assumption of a ten year equipment life, nor the underlying assertion regarding wear and tear. The analyses must use a reasonable estimate of the actual life of the control equipment for each control technology, based on the best evidence available. In order to use an equipment life that is shortened based on the harsh climate, evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as turbines.
2. Control Technology Availability – Technically feasible control technologies may only be eliminated based on lack of availability if the analysis includes documented information from multiple control equipment vendors (who provide the technology in question) which confirms the technology is not available for the emission unit in question. For example, the North Pole analysis concludes that flue gas recirculation is not technically feasible for NO_X control based on the statement that "FGR is not available with the vendor-provided Low-NO_X combustor retrofit package for these boilers." Written documentation from multiple vendors must be included to support this statement.
3. Basis for Costs and Assumptions – Documents cited in the analyses which form the basis for costs used in the analyses and assumptions made in the analyses must be provided. For example, within the analysis of SCR for the North Pole facility (see page 30), many of the costs used for SCR appear to be based either on "past project experience" or "information from other projects". Detailed information forming the basis for these cost assumptions in the analysis must be submitted as part of the BACT analysis. Certain other costs are estimated based on a 1993 EPA document referred to as the "Alternative Control Techniques Document". A copy of this document must be included as an attachment to the analysis if this document forms the basis for information used in the analysis. EPA Region 10 will conduct a more detailed review of the calculations following submittal of this and other requested information.
4. EPA Cost Spreadsheets – Note that the EPA has recently updated the cost manual chapter pertaining to SCR, and developed a cost spreadsheet to be used for evaluation of this technology

[1] Golden Valley Electric Association, Voluntary $PM_{2.5}$ Serious Nonattainment Area BACT Analysis for the North Pole Facility, August 2017

for cost effectiveness[2]. The EPA spreadsheet was developed to evaluate cost effectiveness of SCR as applied to boilers, so cannot be directly applied to turbines. However, the cost analyses for SCR developed for the GVEA emission units must be consistent with the updated cost manual chapter.

5. SCR Space Constraints – The North Pole analysis includes a number of statements regarding space constraints and other installation challenges that the analysis claims complicate or possibly preclude installation of SCR on the turbines, however detailed drawings, site plans and other information have not been submitted to substantiate these claims. One aerial photo of the facility has been included, but all areas surrounding the buildings housing the emission units are marked as unavailable due to "maintenance access areas" or "fuel delivery truck route". Establishing the entire area surrounding the buildings as unavailable for control equipment based on these purposes would require substantially more detailed justification than has been provided. Additionally, in order to establish SCR as not technically feasible due to space constraints or other retrofit factors, detailed site specific information must be submitted in order to establish the basis for such a determination. Installation factors which would complicate the retrofit installation of the control technology should be evaluated by a qualified control equipment vendor and be reflected in a site-specific capital equipment purchase cost and site specific installation cost estimate or quote. Lacking site-specific cost information, all factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor.

6. Costs Not Included – In several locations (i.e., p. 40 of the North Pole analysis), the analyses include the statement that cost estimates are "conservatively low" because they do not include the cost of support systems needed to operate the control equipment. EPA Region 10 believes these costs should be included in the analyses, based on site-specific capital and installation estimates or quotes provided by qualified control equipment vendors. Justification for inclusion of each retrofit-related cost must be included in the analyses. Development of reasonably accurate cost estimates for these retrofit projects is necessary in order to inform the BACT determination for each emission unit and pollutant.

7. Potential vs. Actual Emissions – In some places, the analyses propose BACT determinations based on use of actual emissions. All BACT cost effectiveness calculations must use potential-to-emit (PTE), regardless of the emission unit usage history or actual historical emission rates. The facility should consider operating limits in cases where certain emission units do not need to retain relatively high PTE for facility operational purposes.

[2] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

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April 24, 2015

Naomi Knight, Environmental Officer
Golden Valley Electric Association
PO Box 71249
Fairbanks, AK 99707-1249

Subject: Voluntary BACT Analysis for Zehnder Facility and North Pole Power Plant

Dear Ms. Knight:

Portions of the Fairbanks North Star Borough are in nonattainment with the 24-hour National Ambient Air Quality Standard for Fine Particulate Matter (PM 2.5). The Alaska Department of Environmental Conservation (ADEC) expects that the Environmental Protection Agency (EPA) will change the nonattainment designation from a Moderate Area to a Serious Area in June 2016. Once EPA designates the area as Serious, an 18-month clock begins for submittal of an implementation plan that includes best available control technologies (BACT) analysis and determination for stationary sources with over 70 tons per year (TPY) potential to emit (PTE) for PM2.5 or its precursors.

ADEC has neither the funding nor the in depth knowledge of your facility's infrastructure to determine the most appropriate BACT for your facility. Without the information or resources necessary to conduct detailed cost analysis and produce supporting documentation, ADEC may select a more stringent BACT for your facility in order to be approvable by EPA. In addition, 18 months is likely not adequate to complete a thorough BACT analysis.

Therefore, ADEC requests that your facility voluntarily begin the BACT analysis. We request that you submit an initial BACT analysis to ADEC by December 2015 and the final BACT analysis by March 2016 to ADEC. ADEC is required to make a BACT determination for every eligible facility within the designated PM2.5 nonattainment area and final BACT determinations are ultimately reviewed by EPA and subject to federal approval as part of the federally required PM2.5 implementation plan.

Background

EPA required that ADEC submit a State Implementation Plan (SIP) because portions of the Fairbanks North Star Borough (FSNB) are in nonattainment with the health based 24-hour National

Ambient Air Quality Standard for PM2.5. ADEC submitted an initial, Moderate Area PM2.5 SIP for FNSB to EPA on December 31, 2014.

Unfortunately, this Moderate Area SIP was developed as an impracticable SIP because modeling was unable to demonstrate that attainment with the health standard was possible by December 30, 2015. Preliminary air monitoring results also indicate that FNSB will not demonstrate attainment in 2015. Attainment is calculated on a rolling three year average of the highest 98th percentile concentration at each monitor. When those monitoring results become final in May 2016 and an official three year design value is calculated, the FNSB non-attainment area will remain over the 24-hr PM 2.5 standard of 35 $\mu g/m^3$. The final determination of this design value will result in the FNSB non-attainment area being reclassified from a Moderate Area to a Serious Area[1] (40 CRF Parts 50, 51 and 93). This reclassification will happen by operation of law as outlined in Clean Air Act Sections 188 and 189. It is anticipated that the formal designation to Serious Area will occur in June 2016.

A Serious Area designation will result in several new, more stringent requirements, one of which is that all source categories in the nonattainment area that meet the BACT threshold of 70 TPY PTE for $PM_{2.5}$ and its precursor pollutants (NOx, SO2, VOC, NH3) must be analyzed for Best Available Control Measures (BACM). As part of BACM, a Best Available Control Technologies (BACT) analysis will be required. The Serious Area BACT trigger requires the same approach as a PSD/NSR BACT project. A Serious non-attainment area BACT limit is set using a top-down analysis on a case-by-case basis taking into account energy, environmental and economic impacts, and costs. The analysis must include all emission units at the source.

The timelines for completion of the BACT analysis, subsequent BACT determination, and the submittal of the Serious Area SIP are outlined in the preamble of the Particulate Matter 10 (PM10) rule and reconfirmed in the newly proposed $PM_{2.5}$ Implementation Rule[2]. Both rules require a completed SIP 18 months after designation to Serious. This 18 month time period does not allow enough time to thoroughly evaluate BACT, update the emission inventory, complete the modeling and allow for development and processing for a Serious Area SIP.

ADEC believes that it is best for facilities to complete the BACT analysis for their own facilities. ADEC does not have the funding to develop the analysis nor the in depth knowledge of each sources' infrastructure. ADEC would therefore base the cost analysis on the installation of control equipment without being able to factor in all the costs associated with retrofitting existing equipment. Without the detailed cost analysis and supporting documentation to support less stringent BACT options, it is doubtful that the BACT portions of the Serious SIP will be approvable without using the most stringent measures.

By requesting an early BACT analysis for facilities before the official Serious Area designation, it will help ADEC meet the following timelines and ultimately submit a Serious Area SIP to EPA by the required due date. Early analysis also has the potential to increase flexibility for each Stationary Source under the rules.

[1] 40 CFR Parts 50,51 and 93 http://www.epa.gov/airquality/particlepollution/actions.html

[2] http://www.epa.gov/airquality/particlepollution/actions.html

- Serious Area SIP inventory development starts: January, 2015
- BACT kick off meeting: March 5, 2015
- Submit initial BACT results to ADEC: December, 2015
- Submit complete/final BACT analysis to ADEC: March, 2016
- Serious Area SIP modeling by ADEC starts: March, 2016
- Serious Area designation by EPA (Expected): June, 2016
- Serious Area SIP draft: December, 2016
- Serious Area SIP public notice period: February, 2017
- Serious Area SIP submitted by ADEC to EPA: December, 2017

Meeting the BACT analysis requirements is a major component of a Serious SIP. This is a challenging issue. It is important that ADEC accurately reflect the contributions of industrial sources to the air pollution problem and the potential improvements available within this emission sector along with the other emission sources in the community.

ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Denise Koch, Director
Division of Air Quality

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
John Kuterbach, ADEC/ Air Quality
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality

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Denise Koch, Director
Division of Air Quality
Department of Environmental Conservation
410 Willoughby Avenue, Suite 303
PO Box 111800
Juneau, AK 99811-1800

RE: Response to request for additional information for the Best Available Control Technology Technical Memorandum from Golden Valley Electric Association (GVEA) for the North Pole Power Plant and Zehnder Facility.

Dear Ms. Koch,

Golden Valley Electric Association (GVEA) received a request for additional information from the Alaska Department of Environmental Conservation (ADEC) on November 16, 2017 regarding the Best Available Control Technology (BACT) analyses previously submitted for the North Pole Power Plant and Zehnder Facility. The request for additional information included a set of 11 comments from ADEC and 7 comments from EPA region 10. Listed below is each comment followed by GVEA's response.

Overall, GVEA understands from a regulatory perspective that ADEC and EPA wish to have as much information as possible available to substantiate BACT determinations, and that the highest level of engineering detail would require hundreds of thousands of dollars in engineering studies; the real studies that would identify true retrofit feasibility and true costs. In preparing the BACT analyses GVEA worked to provide a level of detail that is commonly commensurate with BACT analyses and practical to obtain. With respect to the evaluation of NOx BACT in particular, GVEA finds itself in a dilemma while waiting for the outcome of ADEC's NOx precursor demonstration, hesitant to over invest in costly engineering studies that many not be necessary.

ADEC Comments

1. Equipment Life – Page 31 of the North Pole analysis and Page 27 of the Zehnder analysis state "Because of the harsh climate, equipment in this far north location experiences more wear and tear than equipment in moderate climates. On this basis, a ten year return on the [water injection and] SCR system is assumed to be reasonable." This same assumption is made for the other control devices. ADEC identified that the EPA Air Pollution Control Cost Manual uses a hypothetical example that assumes the control equipment has a useful life of ten years. However the cost analyses must use a reasonable estimate of the actual life of the control equipment for each control technology. In order to use an equipment life that is shorter than 30 years, evidence must be provided to support the claim that 10 years is a reasonable timeframe for equipment life. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as turbines.

   GVEA response:

   The 10-year equipment life as used in the calculations for capital recover in the Zehnder Plant and North Pole Plant BACT analyses is consistent with established ADEC practice and previously approved PSD permitting BACT analyses evaluated by ADEC over the past 20 years. GVEA believes this 10-year equipment life timeframe is appropriate for equipment operated in the harsh Alaska climate and falls within the equipment lifetimes used in the EPA Air Pollution Control Cost Manual (sixth edition, EPA/452/B-02-001, Control Cost Manual) which uses equipment lifetimes between 5 and 30 years. Ten, 15, and 20-year lifespans are frequently used in the manual.

   As examples, two recent Alaskan permits with BACT analyses based on a 10-year equipment life include

   - *The BACT analysis for the Doyon Utilities JBER Electric, Gas & Sanitary Services Permit AQ0237CPT04 dated May 8, 2013. See the footnote to Table B-4 of the TAR to that permit.*
   - *The BACT analysis for the Agrium U.S. Inc. Kenai Nitrogen Operations Permit AQ0083CPT06 dated January 6, 2015. See the table on page 24 (of 171) in the TAR to that permit.*

2. BACT limits – BACT limits by definition, are numerical emission limits. However regulation allows a design, equipment, or work/operational practices if technological or economic limitations make a measurement methodology infeasible. Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for pollutant for each emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. Measures to minimize the occurrence of these periods, or to minimize emissions during these periods are control options. Combinations of steady-state control options and SSM control options can be combined to create distinct control strategies. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

GVEA response:

BACT Limits for Normal Operation

The numerical emissions limits that were proposed as BACT selections and that were provided in the Zehnder Power Plant and North Pole Power Plant BACT analyses are summarized in attached Tables 2-1 and 2-2, respectively. Averaging periods, which were inadvertently omitted from the BACT analysis reports, are also included in Tables 2-1 and 2-2.

The averaging periods provided in Tables 2-1 and 2-2 are not an indication of compliance demonstration methodology. Source testing is not an appropriate compliance demonstration methodology for the Zehnder plant and North Pole plant boilers because the units are very small, diesel-fired, and not operated continuously. Startups and shutdowns are typically unscheduled events, but source test planning and mobilization can required up to several months in Alaska because source testing teams and equipment frequently must be brought to Alaska from the Lower 48. The requirement to provide a 30 to 60 -day source test notification to ADEC and/or EPA and to prepare and obtain agency approval of a source test plan also reduces scheduling flexibility. The agency-mandated source testing protocol typically requires that three 1-hour test runs be completed for a test to be valid, while typical startups and shutdowns have a much shorter duration. As a result, retaining records demonstrating proper operation and maintenance is the appropriate compliance demonstration method. Based on the same rationale, the compliance demonstration methodology for the Zehnder plant and North Pole plant emergency diesel-fired reciprocating engines should be retaining records demonstrating proper operation and maintenance.

GVEA wishes to note that while preparing this response, one emission factor error was found in each of the Zehnder plant and North Pole plant BACT analysis reports, but in neither case is the BACT analyses affected.[1]

BACT Limits for Startup, Shutdown, and Malfunction (SSM)

The BACT affected emission units at the Zehnder and North Pole plants have short startup durations, normally ranging from 15 to 30 minutes. The shutdown durations are similarly short, typically less than 15 minutes for all of the BACT affected emission units. For startup, shutdown BACT available options are numerical emission limits, or duration

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[1] *Table 3-15 of the Zehnder report incorrectly lists the nitrogen oxides (NO_x) emission rate for EUs 3 and 4 as 0.0022 pounds per horsepower-hour (lb/hp-hr). The correct BACT emission rate for NO_x emissions from EUs 3 and 4 is 0.024 lb/hp-hr. The NO_x BACT analysis in Section 3 of the Zehnder plant report is based on the correct emission factor. Table 3-23 of the North Pole report incorrectly lists the NO_x emission rate for EU 7 as 0.0022 lb/hp-hr. The correct BACT emission rate for NO_x emissions from EU 7 is 0.031 lb/hp-hr. The NO_x BACT analysis in Section 3 of the North Pole plant report is based on the correct emission factor.*

limits. For malfunction BACT available options are numerical emission limits, or the expeditious return to normal operation or shut down for repairs.

For startup and shutdown, numerical emission limits are not a practical BACT selection for these emission units because demonstrating compliance with such a limit is not technically feasible as a practical matter. Specifically, the startup and shutdown periods are too short to enable performance testing using the methods provided in Appendix A to 40 Code of Federal Regulations (CFR) 60.

As an allowed alternative, the BACT limit available for all emission units and for all air pollutants is the specification of duration limits for startup and shutdown. This proposed work and operational practice is consistent with the BACT guidance and enables a practical methodology for demonstrating compliance during startup and shutdown period. Table 2-3 shows the proposed BACT startup and shutdown durations for emission units at the Zehnder Facility while Table 2-4 shows the proposed BACT startup and shutdown durations for emission units at the North Pole Plant.

For malfunctions, numerical emission limits are not a practical BACT selection for the Zehnder and North Pole emission units during a malfunction because demonstrating compliance with such a limit is not technically feasible as a practical matter. Specifically, predicting when or for how long a malfunction might occur is not possible because of the nature of malfunction events. As a result, demonstrating compliance with numerical emission limits during a malfunction is not practical using the performance testing methods provided in Appendix A to 40 CFR 60.

As an allowed alternative, the BACT limit for all air pollutants and emission units is to restore the malfunctioning emission unit to normal operation as soon as is practical or proceed with shutting down the emission unit until repairs can be made. This proposed work and operational practice is consistent with the BACT guidance and enables a practical methodology for demonstrating compliance during malfunction. Table 2-2 also shows the proposed malfunction BACT for the emission units at the Zehnder Facility and Table 2-4 shows the proposed BACT for the emission units at the North Pole Plant.

3. Cost Analyses – Page 44 of the North Pole analysis indicates that EUs 1 and 2 have historically low run hours. Page 34 of the Zehnder analysis state that "GVEA believes that an economic analysis based on the actual emissions and operations of these turbines is more relevant for purposes of determining viable ways to reduce PM2.5 ambient concentrations in the Fairbanks area." However, all BACT cost effectiveness calculations must be based upon the potential to emit, and not on historic operation. Please update the cost analyses using the unrestricted potential to emit for each of the emissions units or propose operational limits (including control efficiencies associated with limited operation). Additionally, see Comments 4, 5, and 6 for additional information related to retrofit costs, baseline emissions, and factor of safety.

GVEA response:

The North Pole Plant and Zehnder Plant BACT analyses reports submitted in August 2017 do provide the cost effectiveness based on potential to emit (PTE). The cost effectiveness tables and associated page numbers for each pollutant and each control evaluated are provided below in Table 3-1.

Table 3-1. Location of BACT Cost Effectiveness Based on PTE

North Pole Plant				
EU ID	**Pollutant**	**Control Cost Effectiveness Evaluated**	**Table**	**Page**
EU ID 1	NO_x	SCR with Water Injection	Table 3-5	51
EU ID 2	NO_x	SCR with Water Injection	Table 3-7	53
EU ID 1	NO_x	SCR	Table 3-9	55
EU ID 2	NO_x	SCR	Table 3-11	57
EU ID 1	NO_x	Water Injection	Table 3-13	59
EU ID 2	NO_x	Water Injection	Table 3-15	61
EU ID 1	SO_2	ULSD	Table 5-4	103
EU ID 2	SO_2	ULSD	Table 5-5	104
Zehnder Plant				
EU ID	**Pollutant**	**Control Cost Effectiveness Evaluated**	**Table**	**Page**
EU IDs 1 and 2	NO_x	SCR with Water Injection	Table 3-5	42
	NO_x	SCR	Table 3-7	44
	NO_x	Water Injection	Table 3-9	46
	SO_2	ULSD	Table 5-4	81

GVEA understands that a traditional BACT process typically evaluates control cost effectiveness based on PTE and did present those costs. GVEA also understands that BACT decisions are made on a case-by-case basis so that criteria specific to each BACT situation can be properly considered. In this case, GVEA believes that the historically low actual operating hours and associated emissions from the North Pole Plant EUs 1 and 2, and the Zehnder Plant EUs 1 and 2 are representative of the actual contribution emissions from these plants have made to the measured ambient $PM_{2.5}$ concentrations. Because the GVEA cooperative members would bear the economic burden of paying for emission controls that would in practical reality do very little to reduce regional ambient $PM_{2.5}$ concentrations, GVEA proposes that basing the BACT cost effectiveness on the historical actual operating hours is appropriate.

GVEA believes it is premature to commit to any operating limitations. Though these emission units have historically operated only a few hours on an annual basis, all of the emission units are critical to providing reliable power to our cooperative members in the event GVEA loses other generating units or is unable to receive purchased power from Southcentral Alaska. Having available generation is especially important during the coldest winter months when reliable power is critical to maintain the health and safety of

our members. Before knowing the outcome of the ADEC NO_x precursor demonstration, GVEA is uncomfortable committing to restrictions on available operating hours that may be unnecessary if the NOx precursor demonstration is successful.

4. Retrofit Costs – EPA's Control Cost Manual indicates that study-level cost estimates (± 30 percent) should not include a retrofit factor greater than 30 percent, so detailed cost estimates (± 5 percent) is required for higher factors. High retrofit cost factors (50 percent or more) may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement). Provide detailed cost analyses and justification for any difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analyses.

   GVEA response:
   GVEA did not use stand-alone retrofit factors in the BACT cost analyses presented in the August 2017 reports, rather vendor supplied cost information took into account the retrofit installation along with potential complications and cost increases associated with the Alaskan location.

5. Baseline Emissions – Include the baseline emissions for all emission units included in the analyses. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). NSPS and NESHAP requirements are not considered in calculating the baseline emissions. The baseline is usually the legal limit that would exist, but for the BACT determination. Baseline takes into account the effect of equipment that is part of the design of the unit (e.g., water injection and low NOx burners) because they are considered integral components to the unit's design. If the uncontrolled emission rate is "soft," run the cost effectiveness calculations using two or three different baselines.

   GVEA response:
   For both the Zehnder plant and North Pole plant analyses submitted in August 2017, baseline emissions were provided in Section 1, in Tables 1-2 through 1-5. The baseline emission rates incorporate existing emission control devices and enforceable emission and operating limits.

6. Factor of Safety – If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.

   GVEA response:
   GVEA did not feel safety factors were warranted and they were not included in the BACT emission limits proposed in the BACT analysis reports submitted in August 2017.

7. Good Combustion Practices –For each emission unit type (oil fuel-fired turbines, combined cycle turbines, emergency generator engines, and boilers) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices. Include any work or operational practices that will be implemented and describe how continuous compliance with good combustion practices will be achieved.

   GVEA response:
   GVEA's current practice and proposed practice to achieve good combustion practices is the adherence to the original equipment manufacturer (OEM) recommendations for operation and maintenance of all emission units. Good combustion practices are integral to these OEM recommendations, so following the recommendations intrinsically assures compliance with good combustion practices. Set points for efficient combustion are also set into the control systems and those parameters are kept constant. For building heaters the OEM guidelines are followed for tuning and operation and O_2 balance is periodically measured.

8. Alternate Fuel – Page 98 of the North Pole analysis indicates that "the capital costs incurred to switch fuels [to ULSD] would include an estimated capital cost of $30,425,000 to install bulk fuel storage." Please provide a full evaluation of the fuel change impacts, fuel pricing, and bulk storage facility pricing. Based on the fuel supply information gathered for the BACM analysis for the Fairbanks Serious SIP, the Department is aware of more than one supplier of alternate fuels. Please make sure all supplier cost information is addressed for all emission units that are evaluating a fuel switch.

   GVEA response:
   Ensuring the resilient and economical supply of fuel for both normal and emergency operations is extremely important to GVEA and as such the evaluation of fuel vendors within Alaska and the Pacific Northwest is a normal part of strategic planning. The capital costs used in the BACT were developed with the assistance of a technical memo provided by PDC Engineers, and a summary analysis provided by an Energy Analyst with Leidos Engineering. The supporting documentation is provided in the separately submitted package under request for confidentiality.

9. Cost Analysis Spreadsheets – The BACT analyses for North Pole and Zehndar Facilities include emissions, cost effectiveness, and incremental cost effectiveness calculations, but none of these calculations have been submitted in a spreadsheet format. Please submit the electronic versions of the spreadsheets used in determining the cost effectiveness for any control technology not selected as the highest level of control.

   GVEA response:
   The enclosed disk contains the electronic versions of the spreadsheets used in determining the cost effectiveness for all control technologies evaluated.

10. Confidential Documentation – The BACT analyses for North Pole and Zehnder Facilities have indicated that details related to costs were included in a separately submitted package under application for confidentiality of records. Please submit the supporting documentation so the Department can conduct a more detailed review of the analyses and calculations.

    GVEA response:
    The supporting documentation has been submitted under separate cover dated December 22, 2017

11. Control Technology Availability – For the North Pole Facility, include Flue Gas Recirculation in the review of NOx control technologies for diesel-fired boilers. Rank the control technologies by efficiency (specify % control). Select the best performing control technology as BACT or provide specific energy, environmental, and economic impacts and other costs justification for why each better performing control technology was not selected instead of good combustion practices. Provide a numerical NOx emission limit for the diesel-fired boilers or identify the work or operational practices that will be utilized to ensure compliance with proposed limits.

    GVEA response:
    Aaron Simpson of ADEC and Courtney Kimball of SLR (a GVEA consultant) discussed this question during a phone call on November 30, 2017. The North Pole facility does not have any diesel-fired boilers. Mr. Simpson indicated that the comment was meant to address the diesel-fired boilers at the Zehnder facility (EUs 10 and 11). Mr. Simpson and Ms. Kimball agreed that while Flue Gas Recirculation (FGR) is an available emission control technology, vendor information indicates that boiler efficiency would decrease as a result of FGR use. This information is provided in Section 3.2.3 of the Zehnder BACT analysis report. Upon further review of this section of the report, Mr. Simpson stated that no further response to this question was necessary.

EPA Comments

1. Equipment Life – Page 31 of the North Pole analysis states "a standardized ten year return on investment at seven percent interest rate is assumed". This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in this far north location experiences more wear and tear than equipment in moderate climates". The analysis includes no further information to support the assumption of a ten year equipment life, nor the underlying assertion regarding wear and tear. The analyses must use a reasonable estimate of the actual life of the control equipment for each control technology, based on the best evidence available. In order to use an equipment life that is shortened based on the harsh climate, evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as turbines.

GVEA response:
Please see response to ADEC Comment 1 above.

2. Control Technology Availability – Technically feasible control technologies may only be eliminated based on lack of availability if the analysis includes documented information from multiple control equipment vendors (who provide the technology in question) which confirms the technology is not available for the emission unit in question. For example, the North Pole analysis concludes that flue gas recirculation is not technically feasible for NO_x control based on the statement that "FGR is not available with the vendor-provided Low-NO_x combustor retrofit package for these boilers." Written documentation from multiple vendors must be included to support this statement.

   GVEA response:
   Please see response to ADEC Comment 11 above, Aaron Simpson of ADEC and Courtney Kimball of SLR (a GVEA consultant) discussed flue gas recirculation during a phone call on November 30, 2017. The North Pole facility does not have any diesel-fired boilers. Mr. Simpson indicated that his comment was meant to address the diesel-fired boilers at the Zehnder facility (EUs 10 and 11). Mr. Simpson and Ms. Kimball agreed that while Flue Gas Recirculation (FGR) is an available emission control technology, vendor information indicates that boiler efficiency would decrease as a result of FGR use. This information is provided in Section 3.2.3 of the Zehnder BACT analysis report. Upon further review of this section of the report, Mr. Simpson stated that no further response to this question was necessary for ADEC Comment 11. GVEA defers to this conversation in response to this comment.

3. Basis for Costs and Assumptions – Documents cited in the analyses which form the basis for costs used in the analyses and assumptions made in the analyses must be provided. For example, within the analysis of SCR for the North Pole facility (see page 30), many of the costs used for SCR appear to be based either on "past project experience" or "information from other projects". Detailed information forming the basis for these cost assumptions in the analysis must be submitted as part of the BACT analysis. Certain other costs are estimated based on a 1993 EPA document referred to as the "Alternative Control Techniques Document". A copy of this document must be included as an attachment to the analysis if this document forms the basis for information used in the analysis. EPA Region 10 will conduct a more detailed review of the calculations following submittal of this and other requested information.

   GVEA response:
   GVEA believes providing cost estimate elements based on "past project experience" or "information from other projects" without providing detailed information is appropriate for this BACT analysis, and is commensurate with an acceptable level of engineering study and cost. Stanley Consultants Inc. (SCI), is a multi-disciplinary engineering company that has provided decades of service to the power generation industry. Services that include new plant design and upgrades and retrofits. SCI assisted in the gathering of engineering estimates, vendor estimates, and did supply information based on their previous project experience. Providing additional detail would require additional time and expense and GVEA is concerned that is may not be warranted pending results from

ADEC about the modeled impacts that NO_x emissions may or may not be having on actual ambient $PM_{2.5}$ concentrations.

The 1993 EPA Alternative Control Techniques Document is specifically cited in the References section (immediately following Section 6) of the North Pole BACT Analysis Report. The document is available on the EPA website[8] and has been supplied with other files on the included DVD-ROM

4. EPA Cost Spreadsheets – Note that the EPA has recently updated the cost manual chapter pertaining to SCR, and developed a cost spreadsheet to be used for evaluation of this technology for cost effectiveness. The EPA spreadsheet was developed to evaluate cost effectiveness of SCR as applied to boilers, so cannot be directly applied to turbines. However, the cost analyses for SCR developed for the GVEA emission units must be consistent with the updated cost manual chapter.

GVEA response:
The NO_x BACT analyses for SCR do not incorporate the November 2017 changes to Section 4, Chapter 2 of the EPA Control Cost Manual (which was posted to the EPA website in December 2017) because EPA issued those changes after the BACT analysis reports were submitted to ADEC. The August 2017 submittal was prepared to be consistent with the previous version. GVEA is aware that interest rates were modified and lowered from 7 percent to 4.25 percent, however in the short time allowed to prepare these responses has not modified the reports and the analyses to reflect this change.

5. SCR Space Constraints – The North Pole analysis includes a number of statements regarding space constraints and other installation challenges that the analysis claims complicate or possibly preclude installation of SCR on the turbines, however detailed drawings, site plans and other information have not been submitted to substantiate these claims. One aerial photo of the facility has been included, but all areas surrounding the buildings housing the emission units are marked as unavailable due to "maintenance access areas" or "fuel delivery truck route". Establishing the entire area surrounding the buildings as unavailable for control equipment based on these purposes would require substantially more detailed justification than has been provided. Additionally, in order to establish SCR as not technically feasible due to space constraints or other retrofit factors, detailed site specific information must be submitted in order to establish the basis for such a determination. Installation factors which would complicate the retrofit installation of the control technology should be evaluated by a qualified control equipment vendor and be reflected in a site-specific capital equipment purchase cost and site specific installation cost estimate or quote. Lacking site-specific cost information, all factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor.

[8] https://www3.epa.gov/ttncatc1/dir1/gasturb.pdf

GVEA response:

As stated in the BACT analyses and intended to be demonstrated on the aerial photographs, GVEA is very concerned with space constraints at both the Zehnder and North Pole sites. This concern is born from our experience in operating and maintaining the units, and maneuvering on the property. The stacks for EU ID's 1 and 2 are split, each having exits on the south and north sides of the building, there is a high voltage substation to the south, and the blue lines represent the circular routes fuel tanker trucks travel to deliver fuel in the most efficient cycle. Marked maintenance areas include access locations for the use of cranes. GVEA believes it would take a very detailed and expensive engineering effort to fully determine the feasibility and cost of SCR installation on EU ID's 1 and 2, and has difficulty justifying that effort until additional information is available from ADEC about the modeled impacts that NO_x emissions may or may not be having on actual ambient $PM_{2.5}$ concentrations. It is very difficult, if not impossible, to gain detailed evaluations and site specific installation estimates from equipment vendors without significant investment.

6. Costs Not Included – In several locations (i.e., p. 40 of the North Pole analysis), the analyses include the statement that cost estimates are "conservatively low" because they do not include the cost of support systems needed to operate the control equipment. EPA Region 10 believes these costs should be included in the analyses, based on site-specific capital and installation estimates or quotes provided by qualified control equipment vendors. Justification for inclusion of each retrofit-related cost must be included in the analyses. Development of reasonably accurate cost estimates for these retrofit projects is necessary in order to inform the BACT determination for each emission unit and pollutant.

GVEA response:

GVEA made every effort to include as many of the support system costs as possible within the scope of this project, however without more detailed and costly engineering and vendor estimates not all equipment is estimated. When available vendor quotes were included. As presented in the separately submitted package under request for confidentiality, recent project incurred costs were apportioned to include reagent preparation equipment. As much available information as possible was gathered, balancing time and expense.

7. Potential vs. Actual Emissions – In some places, the analyses propose BACT determinations based on use of actual emissions. All BACT cost effectiveness calculations must use potential-to emit (PTE), regardless of the emission unit usage history or actual historical emission rates. The facility should consider operating limits in cases where certain emission units do not need to retain relatively high PTE for facility operational purposes.

GVEA response:

Please see response to ADEC Comment 3 above.

In conclusion, GVEA's mission is *to safely provide its member Owners with quality electric service, quality customer service and innovative energy solutions at fair and reasonable prices.* GVEA is committed to being a constructive contributor to improving regional $PM_{2.5}$ concentrations with practical solutions that do not unfairly burden our cooperative members. We recognize that the ultimate path to attainment will be comprised of many smaller contributions, and appeal to ADEC and EPA to work with all stakeholders to find effective and economically viable solutions.

Sincerely,

Nabmi Motton Knight, P.E.
Environmental Health & Safety Officer

Attachments/Enclosures:
Tables 2-1 through 2-4
DVD Disk

cc: Aaron Simpson, ADEC/Air Quality

Table 3-1. Dehydrator Power Plant - Suggested BACT Limits Summary

Emission Unit		Fuel	NO_x BACT			PM_{10} BACT[1]			SO_2 BACT		
ID	Description		Description	Emission Rate[2]	Averaging Period[3]	Description	Emission Rate[2]	Averaging Period[3]	Description	Fuel Sulfur Content	Averaging Period[3]
1_3	Simple Cycle Gas Turbines	Fuel Oil	Good Combustion Practices (existing)	0.94 lb/MMBtu	4 hour block	Good Combustion Practices (existing)	0.033 lb/MMBtu	4 hour block	Fuel Oil and Good Combustion Practices (existing)	0.5 wt. pct. S	4 hour block
3,4	Generator Engines	Diesel	Turbocharger and Aftercooler + Limited Operation (existing)	0.024 lb/hp-hr[4]	4 hour block	Limited Operation (existing)	0.1 lb/MMBtu	4 hour block	Fuel Oil and Good Combustion Practices (existing)	0.5 wt. pct. S	4 hour block
10, 11	Boilers	Diesel	Good Combustion Practices (existing)	20 lb/kgal	4 hour block	Good Combustion Practices (existing)	2.13 lb/kgal	4 hour block	ULSD	0.0015 wt. pct. S	4 hour block

Notes:

[1] CVEA provided direct PM_{10} emissions in the analysis even though Dehydrator Power Plant is not a Serious Nonattainment Area major source for direct PM_{10} emissions. A BACT analysis is not required for this air pollutant.

[2] Emissions are on a per unit basis.

[3] The averaging period is not an indication of compliance demonstration methodology. In some cases, compliance is adequately demonstrated using operating and maintenance records or fuel sulfur content reports.

[4] The NO_x emission factor for EUs 3 and 4 that was provided in Table 3-15 of the Dehydrator BACT analysis report is incorrect. The correct NO_x emission factor is 0.024 lb/hp-hr (3.2 lb/MMBtu of fuel input) consistent with Table 1-3 of the report. The calculations in Section 3 of that report are correctly based on the NO_x emission factor of 0.024 lb/hp-hr.

Table 3-5. North Pole Power Plant - Suggested BACT Limits Summary

Emission Unit		Fuel	NO_x BACT			PM_{10} BACT			SO_2 BACT [3]		
ID	Description		Description	Emission Rate [1]	Averaging Period [2]	Description	Emission Rate [1]	Averaging Period [2]	Description	Emission Rate [1]	Averaging Period [2]
1	Simple Cycle Gas Turbine	Fuel Oil	Limited Operation (existing)	0.58 lb/MMBtu	4 hour block	Good Combustion Practices (existing)	0.12 lb/MMBtu	4 hour block	Good Combustion Practices (existing)	500 ppm S in fuel	4 hour block
2	Simple Cycle Gas Turbine	Fuel Oil	Limited Operation (existing)	0.58 lb/MMBtu	4 hour block	Good Combustion Practices (existing)	0.12 lb/MMBtu	4 hour block	Good Combustion Practices (existing)	500 ppm S in fuel	4 hour block
8,9	Combined Cycle Gas Turbine	LSR	Water Injection (existing)	0.24 lb/MMBtu	4 hour block	Good Combustion Practices (existing)	0.12 lb/MMBtu	4 hour block	LSR (existing)	10 ppm S in fuel	4 hour block
7	Emergency Generator Engine	Fuel Oil	Turbocharger and Aftercooler + Limited Operation (existing)	0.031 lb/hp-hr [3]	4 hour block	Limited Operation + Good Combustion Practices (existing)	0.0022 lb/hp-hr	4 hour block	Good Combustion Practices (existing)	500 ppm S in fuel	4 hour block
11,12	Boiler	Propane	Good Combustion Practices (existing)	13 lb/hgal	4 hour block	Low Sulfur Fuel (existing)	0.7 lb/hgal	4 hour block	Low Sulfur Fuel - Propane (existing)	0.0012 lb/hgal	4 hour block

Notes:

[1] Emissions are on a per unit basis.

[2] The averaging period is not an indication of compliance demonstration methodology. In some cases, compliance is adequately demonstrated using operating and maintenance records or fuel sulfur content reports.

[3] The NO_x emission factor for EU7 that was provided in Table 3-23 of the North Pole BACT analysis report is incorrect. The correct NO_x emission factor is 0.031 lb/hp-hr (0.41 lb/MMBtu of heat input), consistent with Table 1-3 of the report. The calculations in Section 3 of that report are correctly based on the NO_x emission factor of 0.031 lb/hp-hr.

Table 3-3. Zehnder Power Plant - Suggested Startup, Shutdown, and Malfunction BACT Limits Summary

Emission Unit		Startup, Shutdown, and malfunction (SSM) BACT for All Air Pollutants		
ID	Description	Startup	Shutdown	Malfunction
1, 2	Simple Cycle Gas Turbines	Reach stable operation within 30 minutes of initiating startup	Complete shutdown within 15 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.
3,4	Generator Engines	Reach stable operation within 15 minutes of initiating startup	Complete shutdown within 10 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.
10, 11	Boilers	Reach stable operation within 15 minutes of initiating startup	Complete shutdown within 10 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.

Table 2-4. North Pole Power Plant - Suggested Startup, Shutdown, and Malfunction BACT Limits Summary

Emission Unit		Startup, Shutdown, and malfunction (SSM) BACT for All Air Pollutants		
ID	Description	Startup	Shutdown	Malfunction
1	Simple Cycle Gas Turbine	Reach stable operation within 30 minutes of initiating startup	Complete shutdown within 15 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.
2	Simple Cycle Gas Turbine	Reach stable operation within 30 minutes of initiating startup	Complete shutdown within 15 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.
5,6	Combined Cycle Gas Turbine	Reach stable operation within 30 minutes of initiating startup	Complete shutdown within 15 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.
7	Emergency Generator Engine	Reach stable operation within 15 minutes of initiating startup	Complete shutdown within 10 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.
11,12	Boiler	Reach stable operation within 15 minutes of initiating startup	Complete shutdown within 10 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.

EPA-453/R-93-007

Alternative Control Techniques Document— NO_x Emissions from Stationary Gas Turbines

Emission Standards Division

U. S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711
January 1993

ALTERNATIVE CONTROL TECHNIQUES DOCUMENTS

This report is issued by the Emission Standards Division, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, to provide information to State and local air pollution control agencies. Mention of trade names and commercial products is not intended to constitute endorsement or recommendation for use. Copies of this report are available—as supplies permit—from the Library Services Office (MD-35), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711 ([919] 541-2777) or, for a nominal fee, from the National Technical Information Services, 5285 Port Royal Road, Springfield, Virginia 22161 ([800] 553-NTIS).

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1.0 INTRODUCTION

Congress, in the Clean Air Act Amendments of 1990 (CAAA), amended Title I of the Clean Air Act (CAA) to address ozone nonattainment areas. A new Subpart 2 was added to Part D of Section 103. Section 183(c) of the new Subpart 2 provides that:

> [w]ithin 3 years after the date of the enactment of the CAAA, the Administrator shall issue technical documents which identify alternative controls for all categories of stationary sources of...oxides of nitrogen which emit or have the potential to emit 25 tons per year or more of such air pollutant.

These documents are to be subsequently revised and updated as determined by the Administrator.

Stationary gas turbines have been identified as a category that emits more than 25 tons of nitrogen oxide (NO_x) per year. This alternative control techniques (ACT) document provides technical information for use by State and local agencies to develop and implement regulatory programs to control NO_x emissions from stationary gas turbines. Additional ACT documents are being developed for other stationary source categories.

Gas turbines are available with power outputs ranging from 1 megawatt (MW) (1,340 horsepower [hp]) to over 200 MW (268,000 hp) and are used in a broad scope of applications. It must be recognized that the alternative control techniques and the corresponding achievable NO_x emission levels presented in this document may not be applicable for every gas turbine application. The size and design of the turbine, the operating duty cycle, site conditions, and other site-specific factors must be taken into consideration, and the suitability of an

alternative control technique must be determined on a case-by-case basis.

The information in this ACT document was generated through a literature search and from information provided by gas turbine manufacturers, control equipment vendors, gas turbine users, and regulatory agencies. Chapter 2.0 presents a summary of the findings of this study. Chapter 3.0 presents information on gas turbine operation and industry applications. Chapter 4.0 contains a discussion of NO_x formation and uncontrolled NO_x emission factors. Alternative control techniques and achievable controlled emission levels are included in Chapter 5.0. The cost and cost effectiveness of each control technique are presented in Chapter 6.0. Chapter 7.0 describes environmental and energy impacts associated with implementing the NO_x control techniques.

2.0 SUMMARY

This chapter summarizes the more detailed information presented in subsequent chapters of this document. It presents a summary of nitrogen oxide (NO_x) formation mechanisms and uncontrolled NO_x emission factors, available NO_x emission control techniques, achievable controlled NO_x emission levels, the costs and cost effectiveness for these NO_x control techniques applied to combustion gas turbines, and the energy and environmental impacts of these control techniques. The control techniques included in this analysis are water or steam injection, dry low-NO_x combustors, and selective catalytic reduction (SCR).

Section 2.1 includes a brief discussion of NO_x formation and a summary of uncontrolled NO_x emission factors. Section 2.2 describes the available control techniques and achievable controlled NO_x emission levels. A summary of the costs and cost-effectiveness for each control technique is presented in Section 2.3. Section 2.4 reviews the range of controlled emission levels, capital costs, and cost effectiveness. Section 2.5 discusses energy and environmental impacts.

2.1 NO_x FORMATION AND UNCONTROLLED NO_x EMISSIONS

The two primary NO_x formation mechanisms in gas turbines are thermal and fuel NO_x. In each case, nitrogen and oxygen present in the combustion process combine to form NO_x. Thermal NO_x is formed by the dissociation of atmospheric nitrogen (N_2) and oxygen (O_2) in the turbine combustor and the subsequent formation of NO_x. When fuels containing nitrogen are combusted, this additional source of nitrogen results in fuel NO_x formation. Because most turbine installations burn natural gas or light

distillate oil fuels with little or no nitrogen content, thermal NO_x is the dominant source of NO_x emissions. The formation rate of thermal NO_x increases exponentially with increases in temperature. Because the flame temperature of oil fuel is higher than that of natural gas, NO_x emissions are higher for operations using oil fuel than natural gas.

Uncontrolled NO_x emission levels were provided by gas turbine manufacturers in parts per million, by volume (ppmv). Unless stated otherwise, all emission levels shown in ppmv are corrected to 15 percent O_2. These emission levels were used to calculate uncontrolled NO_x emission factors, in pounds (lb) of NO_x per million British thermal units (Btu) (lb NO_x/MMBtu). Sample calculations are shown in Appendix A. These uncontrolled emission levels and emission factors for both natural gas and oil fuel are presented in Table 2-1

TABLE 2-1. UNCONTROLLED NO_x EMISSION FACTORS FOR GAS TURBINES

Manufacturer	Model No.	Output, MW	NO_x emissions, ppmv, dry and corrected to 15% 0_2		NO_x emissions factor, lb NO_x/MMBtu[a]	
			Natural gas	Distillate oil No. 2	Natural gas	Distillate oil No. 2
Solar	Saturn	1.1	99	150	0.397	0.551
	Centaur	3.3	130	179	0.521	0.658
	Centaur "H"	4.0	105	160	0.421	0.588
	Taurus	4.5	114	168	0.457	0.618
	Mars T12000	8.8	178	267	0.714	0.981
	Mars T14000	10.0	199	NA[b]	0.798	NA[b]
GM/Allison	501-KB5	4.0	155	231	0.622	0.849
	570-KA	4.9	101	182	0.405	0.669
	571-KA	5.9	101	182	0.405	0.669
General Electric	LM1600	12.8	144	237	0.577	0.871
	LM2500	21.8	174	345	0.698	1.27
	LM5000	33.1	185	364	0.742	1.34
	LM6000	41.5	220	417	0.882	1.53
	MS5001P	26.3	142	211	0.569	0.776
	MS6001B	38.3	148	267	0.593	0.981
	MS7001EA	83.5	154	228	0.618	0.838
	MS7001F	123	179	277	0.718	1.02
	MS9001EA	150	176	235	0.706	0.864
	MS9001F	212	176	272	0.706	1.00
Asea Brown Boveri	GT8	47.4	430	680	1.72	2.50
	GT10	22.6	150	200	0.601	0.735
	GT11N	81.6	390	560	1.56	2.06
	GT35	16.9	300	360	1.20	1.32
Westinghouse	W261B11/12	52.3	220	355	0.882	1.31
	W501D5	119	190	250	0.762	0.919
Siemens	V84.2	105	212	360	0.850	1.32
	V94.2	153	212	360	0.850	1.32
	V64.3	61.5	380	530	1.52	1.95
	V84.3	141	380	530	1.52	1.95
	V94.3	203	380	530	1.52	1.95

[a]Based on emission levels provided by gas turbine manufacturers, corresponding to rated load at ISO conditions. NO_x emissions calculations are shown in Appendix A.

[b]Not available.

. Uncontrolled NO_x emission levels range from 99 to 430 ppmv for natural gas fuel and from 150 to 680 ppmv for distillate oil fuel. Corresponding uncontrolled emission factors range from 0.397 to 1.72 lb NO_x/MMBtu and 0.551 to 2.50 lb NO_x/MMBtu for natural gas and distillate oil fuels, respectively. Because thermal NO_x is primarily a function of combustion temperature, NO_x emission rates vary with combustor design. There is no discernable correlation between turbine size and NO_x emission levels evident in Table 2-1.

2.2 CONTROL TECHNIQUES AND CONTROLLED NO_x EMISSION LEVELS

Reductions in NO_x emissions can be achieved using combustion controls or flue gas treatment. Available combustion controls are water or steam injection and dry low-NO_x combustion designs. Selective catalytic reduction is the only available flue gas treatment.

2.2.1 Combustion Controls

Combustion control using water or steam lowers combustion temperatures, which reduces thermal NO_x formation. Fuel NO_x formation is not reduced with this technique. Water or steam, treated to quality levels comparable to boiler feedwater, is injected into the combustor and acts as a heat sink to lower

flame temperatures. This control technique is available for all new turbine models and can be retrofitted to most existing installations.

Although uncontrolled emission levels vary widely, the range of achievable controlled emission levels using water or steam injection is relatively small. Controlled NO_x emission levels range from 25 to 42 ppmv for natural gas fuel and from 42 to 75 ppmv for distillate oil fuel. Achievable guaranteed controlled emission levels, as provided by turbine manufacturers, are shown for individual turbine models in Figures 2-1 and 2-2

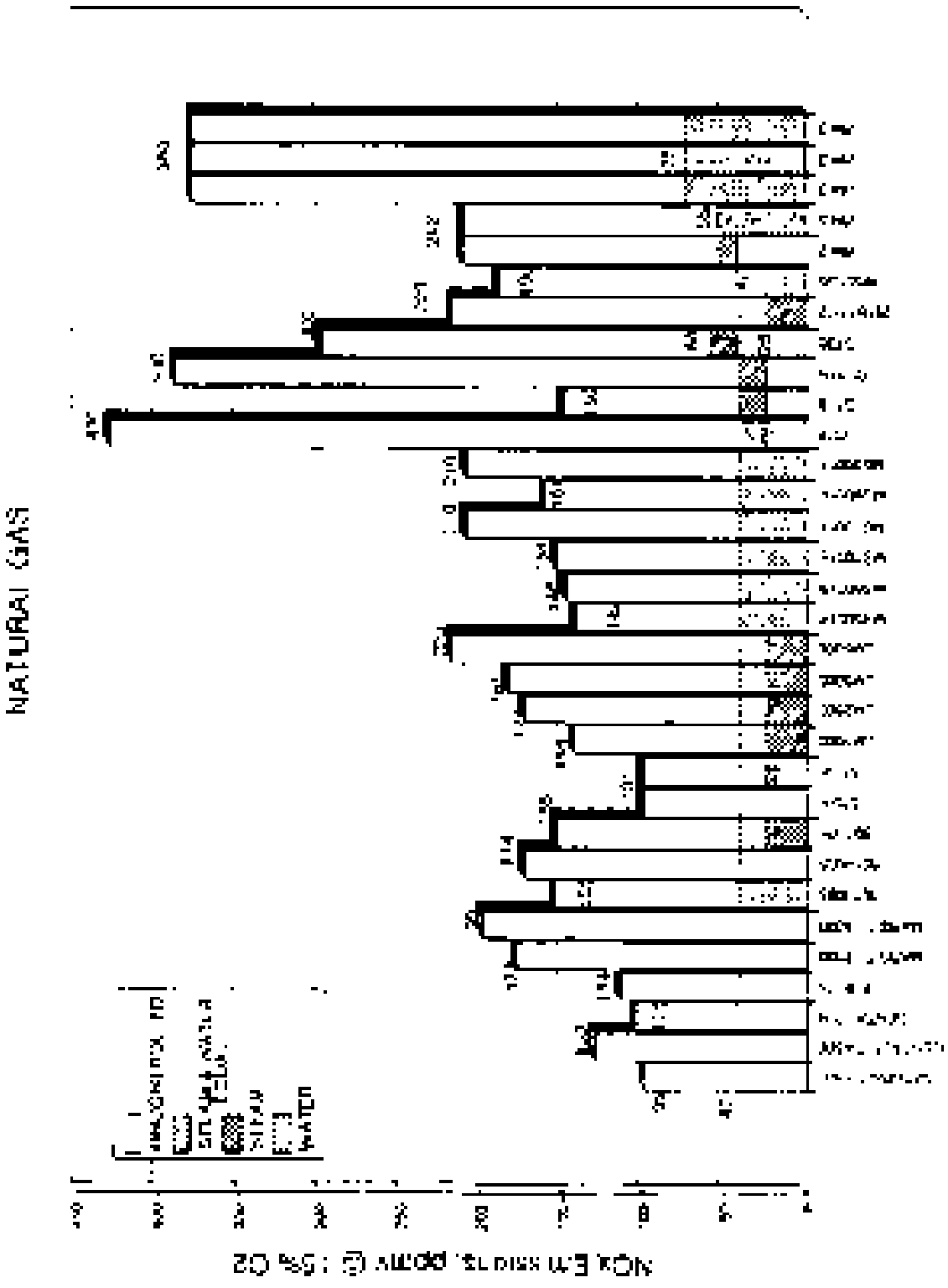


Figure 2-1. **Uncontrolled NOx emission levels and gas turbine manufacturers' guaranteed controlled levels using wet injection. Natural gas fuel.**

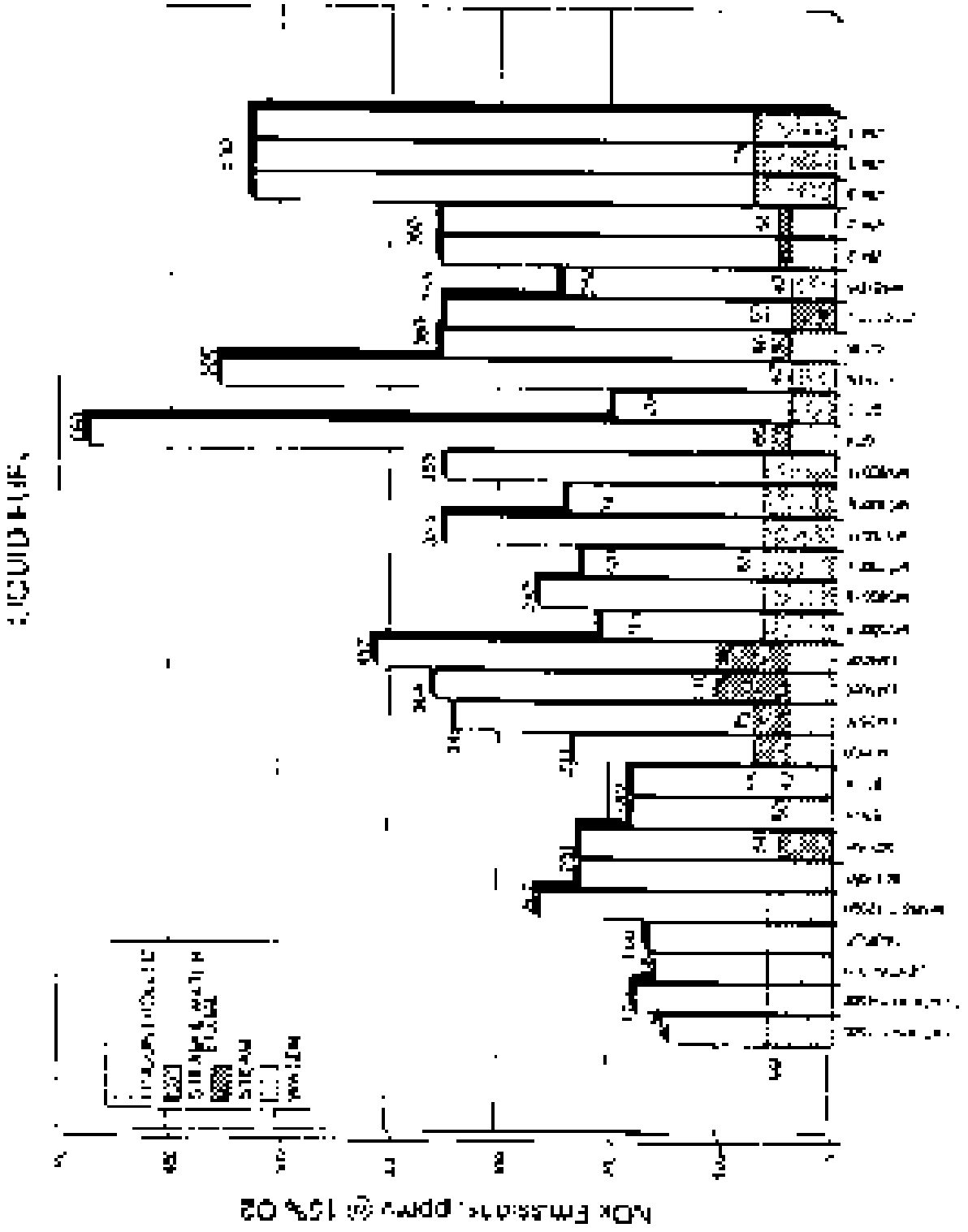


Figure 2-2. **Uncontrolled NO_x emission levels and gas turbine manufacturers' guaranteed controlled levels using wet injection. Distillate oil fuel.**

for natural gas and oil fuels, respectively.

The decision whether to use water versus steam injection for NO_x reduction depends on many factors, including the availability of steam injection nozzles and controls from the turbine manufacturer, the availability and cost of steam at the site, and turbine performance and maintenance impacts. This decision is usually driven by site-specific environmental and economic factors.

A system that allows treated water to be mixed with the fuel prior to injection is also available. Limited testing of water-in-oil emulsions injected into the turbine combustor have achieved NO_x reductions equivalent to direct water injection but at reduced water-to-fuel rates. The vendor reports a similar system is available for natural gas-fired applications.

Dry low-NO_x combustion control techniques reduce NO_x emissions without injecting water or steam. Two designs, lean premixed combustion and rich/quench/lean staged combustion have been developed.

Lean premixed combustion designs reduce combustion temperatures, thereby reducing thermal NO_x. Like wet injection, this technique is not effective in reducing fuel NO_x. In a conventional turbine combustor, the air and fuel are introduced at an approximately stoichiometric ratio and air/fuel mixing occurs simultaneously with combustion. A lean premixed combustor design premixes the fuel and air prior to combustion. Premixing results in a homogeneous air/fuel mixture, which minimizes

localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions. A lean air-to-fuel ratio approaching the lean flammability limit is maintained, and the excess air acts as a heat sink to lower combustion temperatures, which lowers thermal NO_x formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

Lean premixed combustors are currently available from several turbine manufacturers for a limited number of turbine models. Development of this technology is ongoing, and availability should increase in the coming years. All turbine manufacturers state that lean premixed combustors are designed for retrofit to existing installations.

Controlled NO_x emission levels using dry lean premixed combustion range from 9 to 42 ppmv for operation on natural gas fuel. The low end of this range (9 to 25 ppmv) has been limited to turbines above 20 megawatts (MW) (27,000 horsepower [hp]); to date, three manufacturers have guaranteed controlled NO_x emission levels of 9 ppmv at one or more installations for utility-sized turbines. Controlled NO_x emissions from smaller turbines typically range from 25 to 42 ppmv. For operation on distillate oil fuel, water or steam injection is required to achieve controlled NO_x emissions levels of approximately 65 ppmv. Development continues for oil-fueled operation in lean premixed designs, however, and one turbine manufacturer reports having achieved controlled NO_x emission levels below 50 ppmv in limited testing on oil fuel without wet injection.

A second dry low-NO_x combustion design is a rich/quench/lean staged combustor. Air and fuel are partially combusted in a fuel-rich primary stage, the combustion products are then rapidly quenched using water or air, and combustion is completed in a fuel-lean secondary stage. The fuel-rich primary stage inhibits NO_x formation due to low O_2 levels. Combustion temperatures in the fuel-lean secondary stage are below NO_x formation temperatures as a result of the quenching process and the presence of excess air. Both thermal and fuel NO_x are controlled with this design. Limited testing with fuels including natural

gas and coal have achieved controlled NO_x emissions of 25 ppmv. Development of this design continues, however, and currently the rich/quench/lean combustor is not available for production turbines.

2.2.2 Selective Catalytic Reduction

This flue gas treatment technique uses an ammonia (NH_3) injection system and a catalytic reactor to reduce NO_x. An injection grid disperses NH_3 in the flue gas upstream of the catalyst, and NH_3 and NO_x are reduced to N_2 and water (H_2O) in the catalyst reactor. This control technique reduces both thermal NO_x and fuel NO_x.

Ammonia injection systems are available that use either anhydrous or aqueous NH_3. Several catalyst materials are available. To date, most SCR installations use a base-metal catalyst with an operating temperature window ranging from approximately 260° to 400°C (400° to 800°F). The exhaust temperature from the gas turbine is typically above 480°C (900°F), so the catalyst is located within a heat recovery steam generator (HRSG) where temperatures are reduced to a range compatible with the catalyst operating temperature. This operating temperature requirement has, to date, limited SCR to cogeneration or combined-cycle applications with HRSG's to reduce flue gas temperatures. High-temperature zeolite catalysts, however, are now available and have operating temperature windows of up to 600°C (1100°F), which is suitable for installation directly downstream of the turbine. This high-temperature zeolite catalyst offers the potential for SCR applications with simple cycle gas turbines.

To achieve optimum long-term NO_x reductions, SCR systems must be properly designed for each application. In addition to temperature considerations, the NH_3 injection rate must be carefully controlled to maintain an NH_3/NO_x molar ratio that effectively reduces NO_x and avoids excessive NH_3 emissions downstream of the catalyst, known as ammonia slip. The selected catalyst formulation must be resistant to potential masking and/or poisoning agents in the flue gas.

To date, most SCR systems in the United States have been installed in gas-fired turbine applications, but improvements in SCR system designs and experience on alternate fuels in Europe and Japan suggest that SCR systems are suitable for firing distillate oil and other sulfur-bearing fuels. These fuels produce sulfur dioxide (SO_2), which may oxidize to sulfite (SO_3) in the catalyst reactor. This SO_3 reacts with NH_3 slip to form ammonium salts in the low-temperature section of the HRSG and exhaust ductwork. The ammonium salts must be periodically cleaned from the affected surfaces to avoid fouling and corrosion as well as increased back-pressure on the turbine. Advances in catalyst formulations include sulfur-resistant catalysts with low SO_2 oxidation rates. By limiting ammonia slip and using these sulfur-resistant catalysts, ammonium salt formation can be minimized.

Catalyst vendors offer NO_x reduction efficiencies of 90 percent with ammonia slip levels of 10 ppmv or less. These emission levels are warranted for 2 to 3 years, and all catalyst vendors contacted accept return of spent catalyst reactors for recycle or disposal.

Controlled NO_x emission levels using SCR are typically 9 ppmv or less for gas-fueled turbine installations. With the exception of one site, all identified installations operate the SCR system in combination with combustion controls that reduce NO_x emission levels into the SCR to a range of 25 to 42 ppmv. Most continuous-duty turbine installations fire natural gas; there is limited distillate oil-fired operating experience in the United States. Several installations with SCR in the northeast United States that use distillate oil as a back-up fuel have controlled NO_x emission limits of 18 ppmv for operation on distillate oil fuel.

2.3 COSTS AND COST EFFECTIVENESS FOR NO_x CONTROL TECHNIQUES

Capital costs and cost effectiveness were developed for the available NO_x control techniques. Capital costs are presented in Section 2.3.1. Cost-effectiveness figures, in $/ton of NO_x

removed, are shown in Section 2.3.2. All costs presented are in 1990 dollars.

2.3.1 Capital Costs

Capital costs are the sum of purchased equipment costs, taxes and freight charges, and installation costs. Purchased equipment costs were estimated based on information provided by equipment manufacturers, vendors, and published sources. Taxes, freight, and installation costs were developed based on factors recommended in the Office of Air Quality and Planning and Standards Control Cost Manual (Fourth Edition). Capital costs for combustion controls and SCR are presented in Sections 2.3.1.1 and 2.3.1.2, respectively.

2.3.1.1 Combustion Controls Capital Costs. Capital costs for wet injection include a mixed bed demineralizer and reverse-osmosis water treatment system and an injection system consisting of pumps, piping and hardware, metering controls, and injection nozzles. All costs for wet injection are based on the availability of water at the site; no costs have been included for transporting water to the site. These costs apply to new installations; retrofit costs would be similar except that turbine-related injection hardware and metering controls purchased from the turbine manufacturer may be higher for retrofit applications.

The capital costs for wet injection are shown in Figure 2-3, and range from $388,000 for a 3.3 MW (4,430 hp) turbine to $4,830,000 for a 161 MW (216,000 hp) turbine.

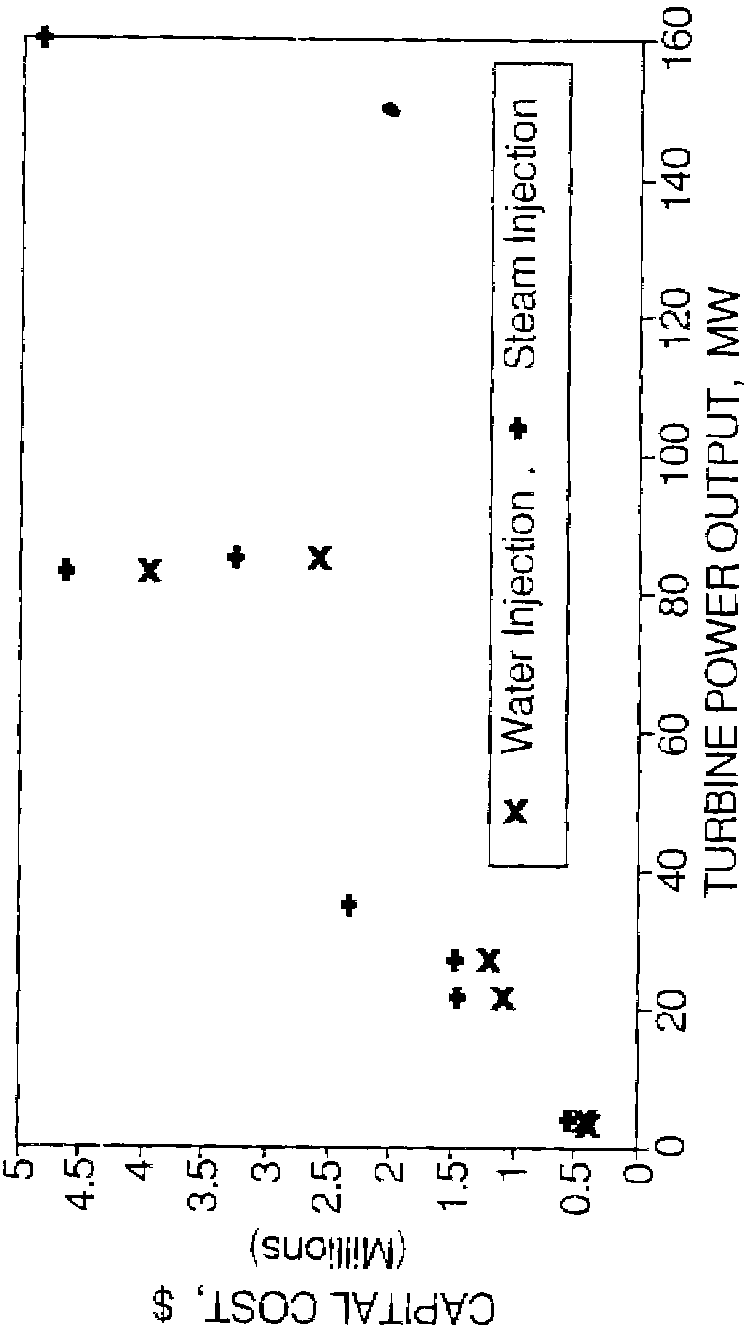


Figure 2-3. Capital costs for water or steam injection.

These capital costs include both water and steam injection systems for use with either gas or distillate oil fuel applications. Figure 2-3 shows that the capital costs for steam injection are slightly higher than those for water injection for turbines in the 3 to 25 MW (4,000 to 33,500 hp) range.

The capital costs for dry low-NO_x combustors are the incremental costs for this design over a conventional combustor and apply to new installations. Turbine manufacturers estimate retrofit costs to be approximately 40 to 60 percent higher than new equipment costs. Incremental capital costs for dry low-NO_x

combustion were provided by turbine manufacturers and are presented in Figure 2-4.

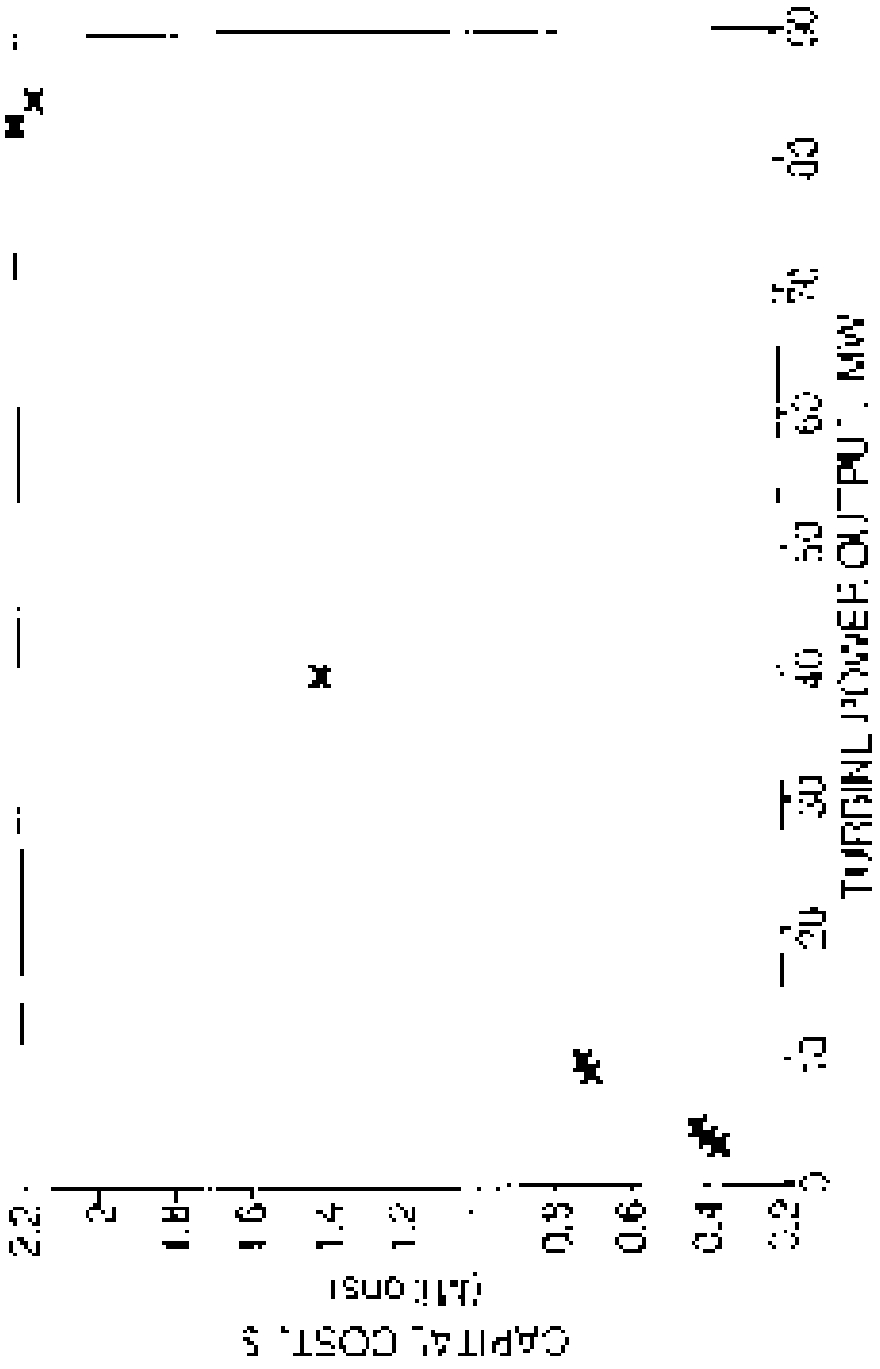


Figure 2-4. Capital costs for dry low-NO_x combustion.

The incremental capital costs range from $375,000 for a 3.3 MW (4,430 hp) turbine to $2.2 million for an 85 MW (114,000 hp) machine. Costs were not available for turbines above 85 MW (114,000 hp).

When evaluated on a $/MW ($/hp) basis, the capital costs for wet injection or dry low-NO_x combustion controls are highest for the smallest turbines and decrease exponentially with increasing turbine size. The range of capital costs for combustion controls, in $/MW, and the effect of turbine size on capital costs are shown in Figure 2-5.

Figure 2-5. Capital costs, in $/MW, for cumbustion controls.

For wet injection, the capital costs range from a high of $138,000/MW ($103/hp) for a 3.3 MW (4,430 hp) turbine to a low of $29,000/MW ($22/hp) for a 161 MW (216,000 hp) turbine. Corresponding capital cost figures for dry low-NO_x combustion range from $114,000/MW ($85/hp) for a 3.3 MW (4,430 hp) unit to $26,000/MW ($19/hp) for an 85 MW (114,000 hp) machine.

2.3.1.2 SCR Capital Costs. Capital costs for SCR include the catalyst reactor, ammonia storage and injection system, and controls and monitoring equipment. A comparison of available cost estimates for base-metal catalyst systems and high-temperature zeolite catalyst systems indicates that the costs for these systems are similar, so a single range of costs was developed that represents all SCR systems, regardless of catalyst type or turbine cycle (i.e., simple, cogeneration, or combined cycle).

The capital costs for SCR, shown in Figure 2-6, range from $622,000 for a 3.3 MW (4,430 hp) turbine to $8.46 million for a 161 MW (216,000 hp) turbine.

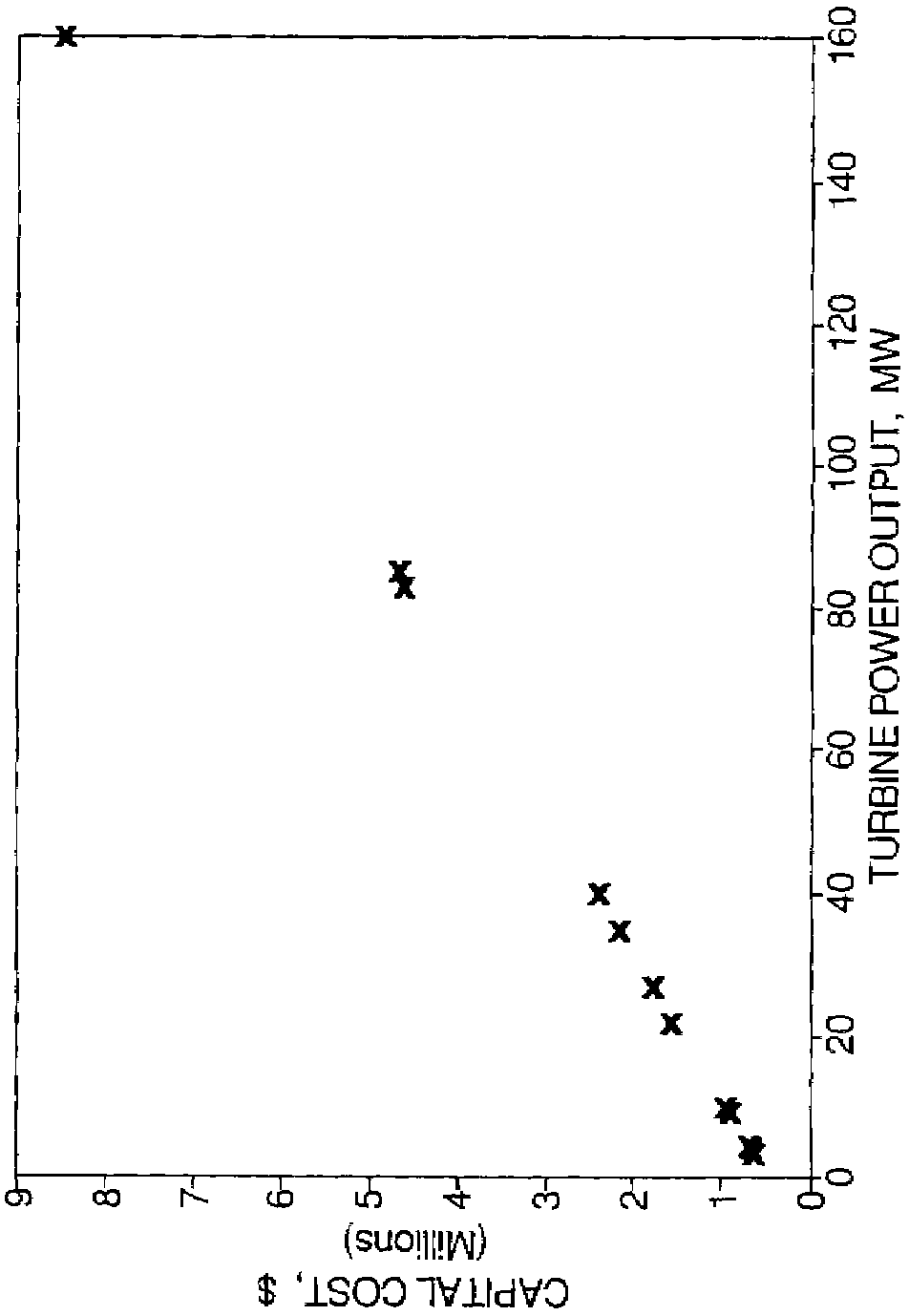


Figure 2-6. Capital costs for selective catalytic reduction.

Figure 2-7 plots capital costs on a $/MW basis and shows that these costs are highest for the smallest turbine, at $188,000/MW ($140/hp) for a 3.3 MW (4,430 hp) unit, and decrease exponentially with increasing turbine size to $52/MW ($40/hp) for a 161 MW (216,000 hp) machine.

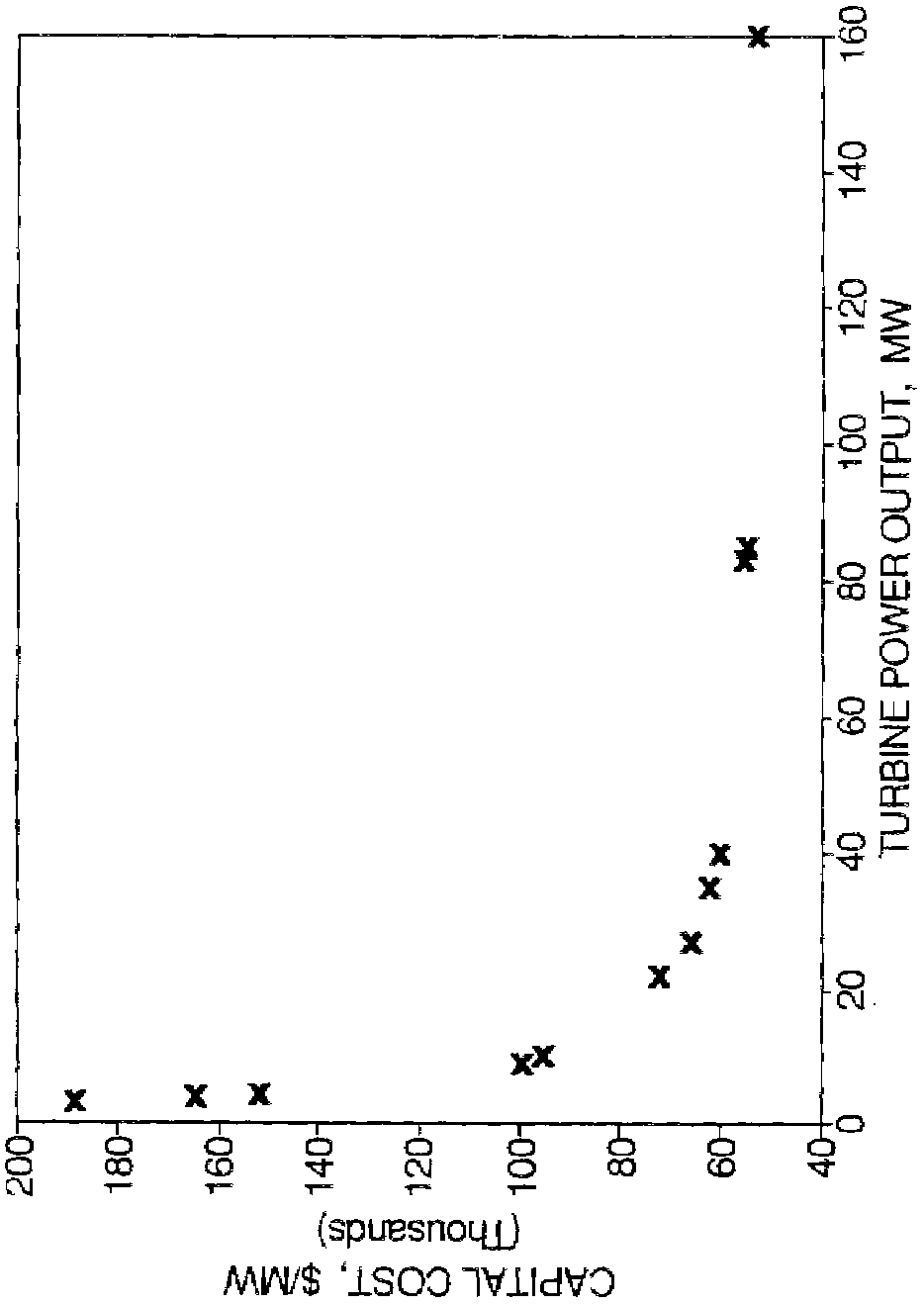


Figure 2-7. Capital costs, in $/MW, for selective catalytic reduction.

These costs apply to new installations firing natural gas as the primary fuel. No SCR sites using oil as the primary fuel were identified, and costs were not available. For this

reason, the costs for gas-fired applications were also used for oil-fired sites. Retrofit SCR costs could be considerably higher than those shown here for new installations, especially if an existing HRSG and ancillary equipment must be moved or modified to accommodate the SCR system.

2.3.2 Cost Effectiveness

The cost effectiveness, in $/ton of NO_x removed, was developed for each NO_x control technique. The cost effectiveness for a given control technique is calculated by dividing the total annual cost by the annual NO_x reduction, in tons. The cost effectiveness presented in this section correspond to 8,000 annual operating hours. Total annual costs were calculated as the sum of all annual operating costs and annualized capital costs. Annual operating costs include costs for incremental fuel, utilities, maintenance, applicable performance penalties, operating and supervisory labor, plant overhead, general and administrative, and taxes and insurance. Capital costs were annualized using the capital recovery factor method with an equipment life of 15 years and an annual interest rate of 10 percent. Cost-effectiveness figures for combustion controls and SCR are presented in Sections 2.3.2.1 and 2.3.2.2, respectively.

2.3.2.1 Combustion Controls Cost Effectiveness. Cost effectiveness for combustion controls is shown in Figure 2-8.

Figure 2-8. Cost effectiveness of combustion controls.

Figure 2-8 indicates that cost effectiveness for combustion controls is highest for the smallest turbines and decreases exponentially with decreasing turbine size. Figure 2-8 also shows that the range of cost effectiveness for water injection is similar to that for steam injection, primarily because the total annual costs and achievable controlled NO_x emission levels for water and steam injection are similar. The cost-effectiveness range for dry low-NO_x combustion is lower than that for wet

$_x$ levels are similar (25 to 42 ppmv), due to the lower total annual costs for dry low-NO_x combustion.

For water injection, cost effectiveness, in $/ton of NO_x removed, ranges from $2,080 for a 3.3 MW (4,430 hp) unit to $575 for an 83 MW (111,000 hp) turbine and $937 for an 85 MW (114,000 hp) turbine. For steam injection, cost effectiveness is $1,830 for a 3.3 MW (4,430 hp), decreasing to $375 for an 83 MW (111,000 hp) turbine, and increasing to $478 for a 161 MW (216,000 hp) turbine. The relatively low cost effectiveness for the 83 MW (111,000 hp) turbine is due to this particular turbine's high uncontrolled NO emissions, which result in a relatively high NO_x removal efficiency and lower cost effectiveness. The cost effectiveness shown in Figure 2-8

number of oil-fired applications with water injection indicates that the cost effectiveness ranges from 70 to 85 percent of the

NO_x removal efficiency achieved in oil-fired applications.

For dry low-NO_x combustion, cost effectiveness, in $/ton of NO_x removed, ranges from $1,060 for a 4.0 MW (5,360 hp) turbine down to $154 for an 85 MW (114,000 hp) machine. A cost effectiveness of $57 was calculated for the 83 MW (111,000 hp) unit. Again, the relatively high uncontrolled NO_x emissions and the resulting high NO_x removal efficiency for this turbine model yields a relatively low cost-effectiveness figure. Current dry low-NO_x combustion designs do not achieve NO_x reductions with oil fuels, so the cost-effectiveness values shown in this section apply only to gas-fired applications.

2.3.2.2 SCR Cost Effectiveness. Cost effectiveness for SCR was calculated based on the use of combustion controls upstream of the catalyst to reduce NO_x emissions to a range of 25 to 42 ppmv at the inlet to the catalyst. This approach was used because all available SCR cost information is for SCR applications used in combination with combustion controls and all but one of the 100+ SCR installations in the United States operate in combination with combustion controls. For this cost analysis, a 5-year catalyst life and a 9 ppmv controlled NO_x emission level was used to calculate cost effectiveness for SCR.

Figure 2-9 presents SCR cost effectiveness. Figure 2-9 shows that, like combustion controls, SCR cost effectiveness is highest for the smallest turbines and decreases exponentially with decreasing turbine size.

Figure 2-9. Cost effectiveness for selective catalytic reduction installed downstream of combustion controls.

Also, because this cost analysis uses a 9 ppmv controlled NO_x emission level for SCR, NO_x reduction efficiencies are higher where the NO_x emission level into the SCR is 42 ppmv than for applications with a 25 ppmv level. Cost effectiveness corresponding to an inlet NO_x emission level of 42 ppmv, in $/ton of NO_x removed, ranges from a high of $10,800 for a 3.3 MW (4430 hp) turbine to $3,580 for a 161 MW (216,000 hp) turbine. For an inlet NO_x emission level of 25 ppmv, the cost-effectiveness range shifts higher, from $22,100 for a 3.3 MW (4,430 hp) installation to $6,980 for an 83 MW (111,000 hp) site.

The range of cost effectiveness for SCR shown in Figure 2-9 applies to gas-fired applications. Cost effectiveness developed for a limited number of oil-fired installations using capital costs from gas-fired applications yields cost-effectiveness values ranging from approximately 70 to 77 percent of those for gas-fired sites. The lower cost-effectiveness figures for oil-fired applications result primarily from the greater annual NO_x reductions for oil-fired applications; the gas-fired capital costs used for these oil-fired applications may understate the actual capital costs for these removal rates and actual oil-fired cost-effectiveness figures may be higher.

Combined cost-effectiveness figures, in $/ton of NO_x removed, were calculated for the combination of combustion controls plus SCR by dividing the sum of the total annual costs by the sum of the NO_x removed for both control techniques. The controlled NO_x emission level for the combination of controls is 9 ppmv. These combined cost-effectiveness figures are presented in Figure 2-10.

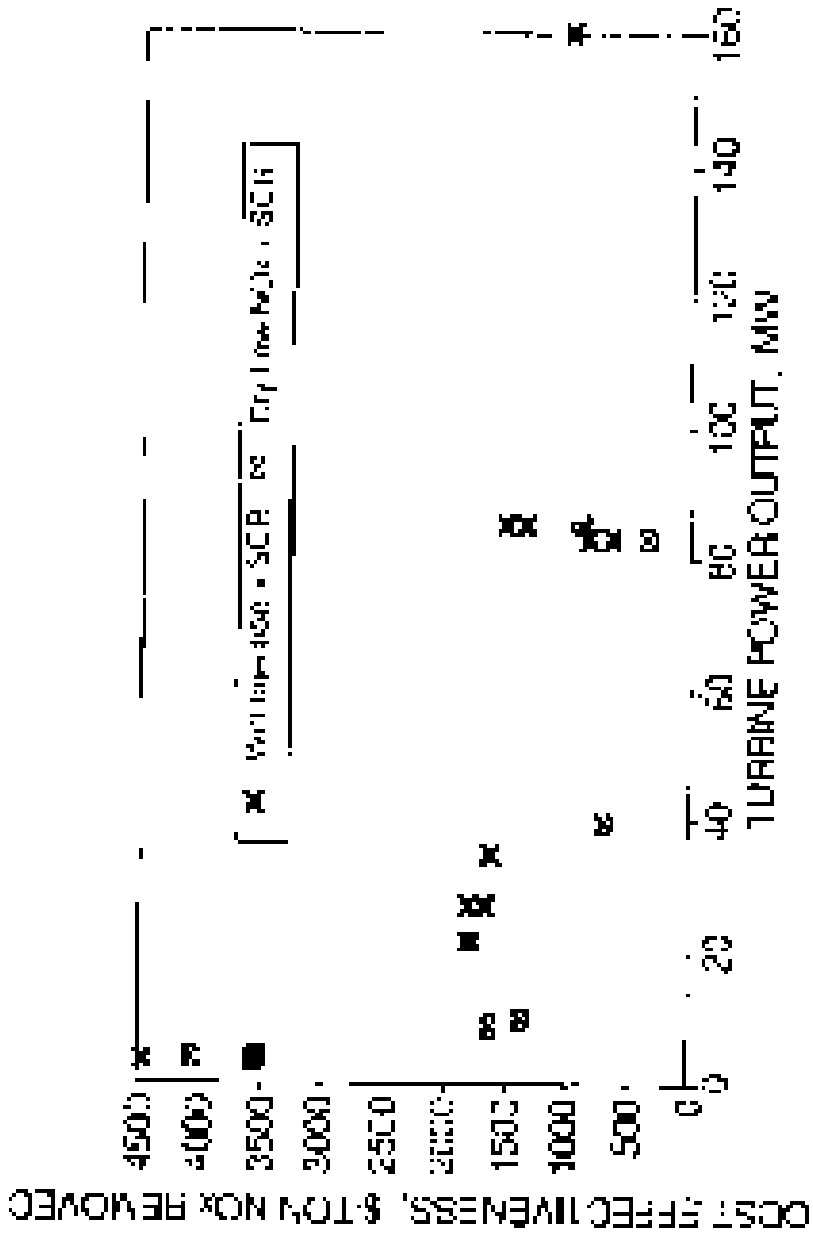


Figure 2-10. Combined cost effectiveness for combustion controls plus selective catalytic reduction.

For wet injection plus SCR, the combined cost effectiveness ranges from $4,460 for a 3.3 MW (4,430 hp) application to $988 for a 160 MW (216,000 hp) site. The $645 cost-effectiveness value for the 83 MW (111,000 hp) turbine is lower than the other turbine models shown in Figure 2-10 due to

the relatively high uncontrolled NO_x emission level for this turbine, which results in relatively high NO_x removal rates and a lower cost effectiveness. For dry low-NO_x combustion plus SCR, combined cost-effectiveness values range from $4,060 to $348 for this turbine size range.

2.4 REVIEW OF CONTROLLED NO_x EMISSION LEVELS AND COSTS

An overview of the performance and costs for available NO_x control techniques is presented in Figure 2-11.

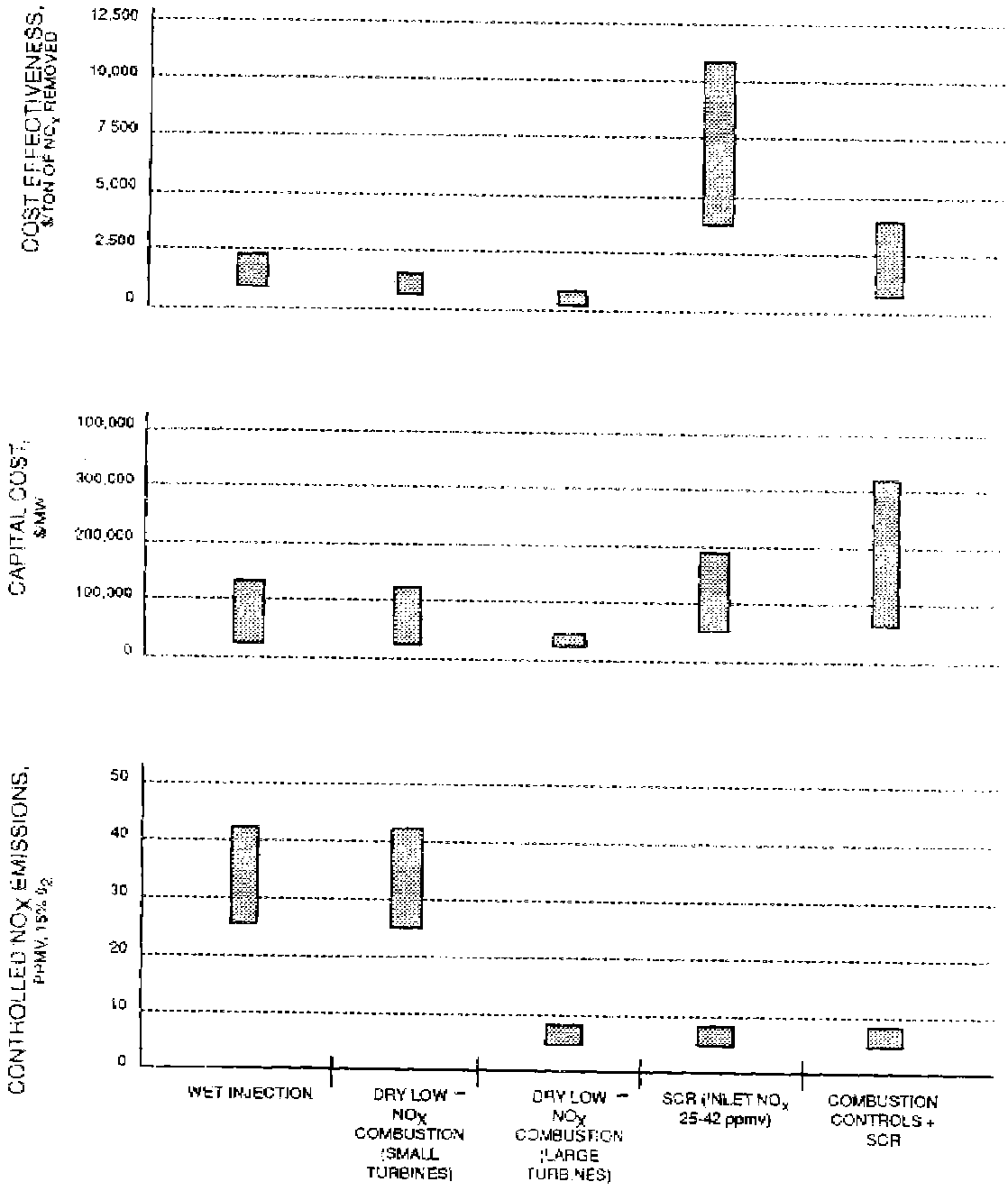


Figure 2-11. Controlled NO_x emission levels and associated capital costs and cost effectiveness for available NO_x control techniques. Natural gas fuel.

Figure 2-11 shows relative achievable controlled NO_x emission levels, capital costs, and cost effectiveness for gas-fired turbine applications. Controlled NO_x emission levels of 25 to 42 ppmv can be achieved using either wet injection or, where available, dry low-NO_x combustion. Wet injection capital costs range from $30,000 to $140,000 per MW ($22 to $104 per hp), and cost effectiveness ranges from $375 to $2,100 per ton of NO_x removed. Dry low-NO_x combustion capital costs range from $25,000 to $115,000 per MW ($19 to $86 per hp), and cost effectiveness ranges from $55 to $1,050 per ton of NO_x removed.

A controlled NO_x emission level of 9 ppmv requires the addition of SCR, except for a limited number of large turbine models for which dry low-NO_x combustion designs can achieve this level. For turbine models above 40 MW (53,600 hp), the capital costs of dry low-NO_x combustion range from $25,000 to $36,000 per MW ($25 to $27 per hp), and the cost effectiveness ranges from $55 to $138 per ton of NO_x removed. Adding SCR to reduce NO_x emission levels from 42 or 25 ppmv to 9 ppmv adds capital costs ranging from $53,000 to $190,000 per MW ($40 to $142 per hp) and yields cost-effectiveness values ranging from $3,500 to $10,500 per ton of NO_x removed. The combination of combustion controls plus SCR yields combined capital costs ranging from $78,000 to $330,000 per MW ($58 to $246 per hp) and cost-effectiveness values ranging from $350 to $4,500 per ton of NO_x removed.

2.5 ENERGY AND ENVIRONMENTAL IMPACTS OF NO_x CONTROL TECHNIQUES

The use of the NO_x control techniques described in this document may affect the turbine performance and maintenance

requirements and may result in increased emissions of carbon monoxide (CO), hydrocarbons (HC), and NH_3. These potential energy and environmental impacts are discussed in this section.

Water or steam injection affects turbine performance and in some turbines also affects maintenance requirements. The increased mass flow through the turbine resulting from water or steam injection increases the available power output. The quenching effect in the combustor, however, decreases combustion efficiency, and consequently the efficiency of the turbine decreases in most applications. The efficiency reduction is greater for water than for steam injection, largely because the heat of vaporization energy cannot be recovered in the turbine. In applications where the steam can be produced from turbine exhaust heat that would otherwise be rejected to the atmosphere, the net gas turbine efficiency is increased with steam injection. Injection of water or steam into the combustor increases the maintenance requirements of the hot section of some turbine models. Water injection generally has a greater impact than steam on increased turbine maintenance. Water or steam injection has the potential to increase CO and, to a lesser extent, HC emissions, especially at water-to-fuel ratios above 0.8.

Turbine manufacturers report no significant performance impacts for lean premixed combustors. Power output and efficiency are comparable to conventional designs. No maintenance impacts are reported, although long-term operating experience is not available. Impacts on CO emissions vary for different combustor designs. Limited data from three manufacturers showed minimal or no increases in CO emissions for controlled NO_x emission levels of 25 to 42 ppmv. For a controlled NO_x level of 9 ppmv, however, CO emissions increased in from 10 to 25 ppmv in one manufacturer's combustor design.

For SCR, the catalyst reactor increases the back-pressure on the turbine, which decreases the turbine power output by approximately 0.5 percent. The addition of the SCR system and associated controls and monitoring equipment increases plant maintenance requirements, but it is expected that these

maintenance requirements are consistent with maintenance schedules for other plant equipment. There is no impact on CO or HC emissions from the turbine caused by the SCR system, but ammonia slip through the catalyst reactor results in NH_3 emissions. Ammonia slip levels are typically guaranteed by SCR vendors at 10 ppmv, and operating experience indicates actual NH_3 emissions are at or below this level.

3.0 STATIONARY GAS TURBINE DESCRIPTION AND INDUSTRY APPLICATIONS

This section describes the physical components and operating cycles of gas turbines and how turbines are used in industry. Projected growth in key industries is also presented.

3.1 GENERAL DESCRIPTION OF GAS TURBINES

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. A common example of a gas turbine is the aircraft jet engine. In stationary applications, the hot combustion gases are directed through one or more fan-like turbine wheels to generate shaft horsepower rather than the thrust propulsion generated in an aircraft engine. Often the heat from the exhaust gases is recovered through an add-on heat exchanger.

Figure 3-1

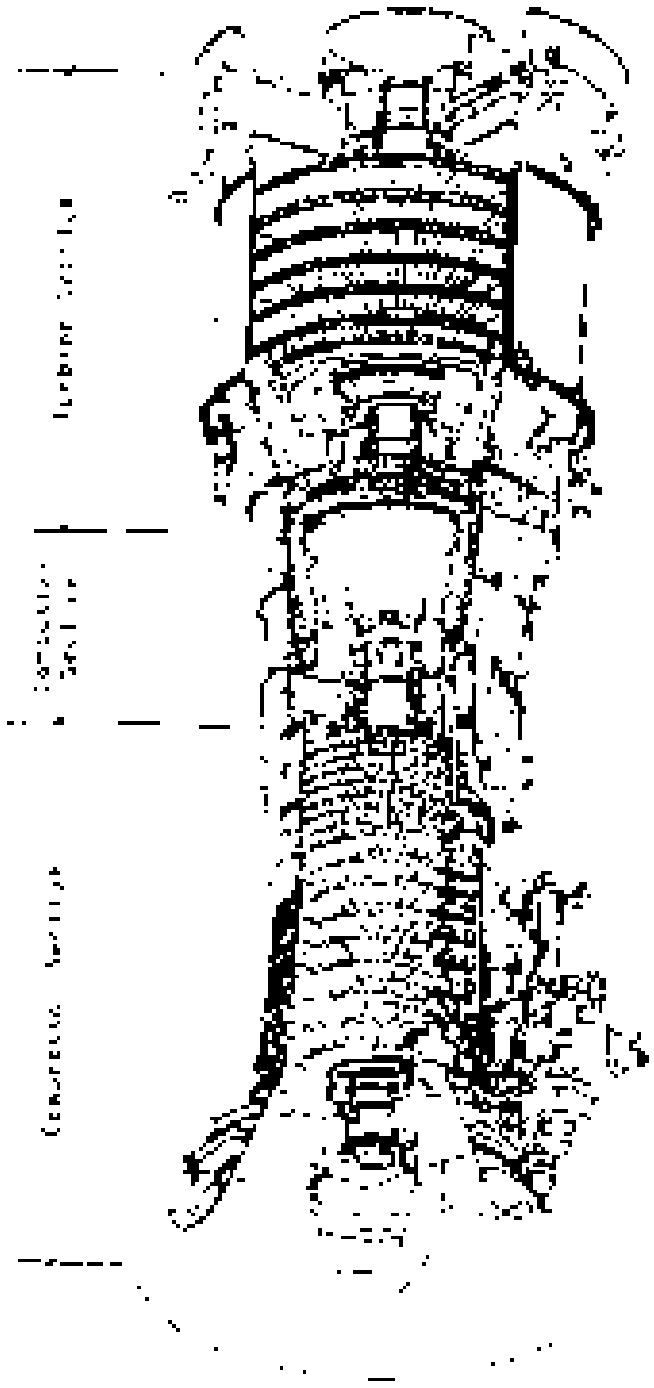


Figure 3-1. The three primary sections of a gas turbine.[1]

presents a cutaway view showing the three primary sections of a gas turbine: the compressor, the combustor, and the turbine.[1] The compressor draws in ambient air and compresses it by a pressure ratio of up to 30 times ambient pressure.[2] The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. There are three types of combustors: annular, can-annular, and silo. An annular combustor is a single continuous chamber roughly the shape of a doughnut that rings the turbine in a plane perpendicular to the air flow. The can-annular type uses a similar configuration but is a series of can-shaped chambers rather than a single continuous chamber. The silo combustor type is one or more chambers mounted external to the gas turbine body. These three combustor types are shown in Figure 3-2

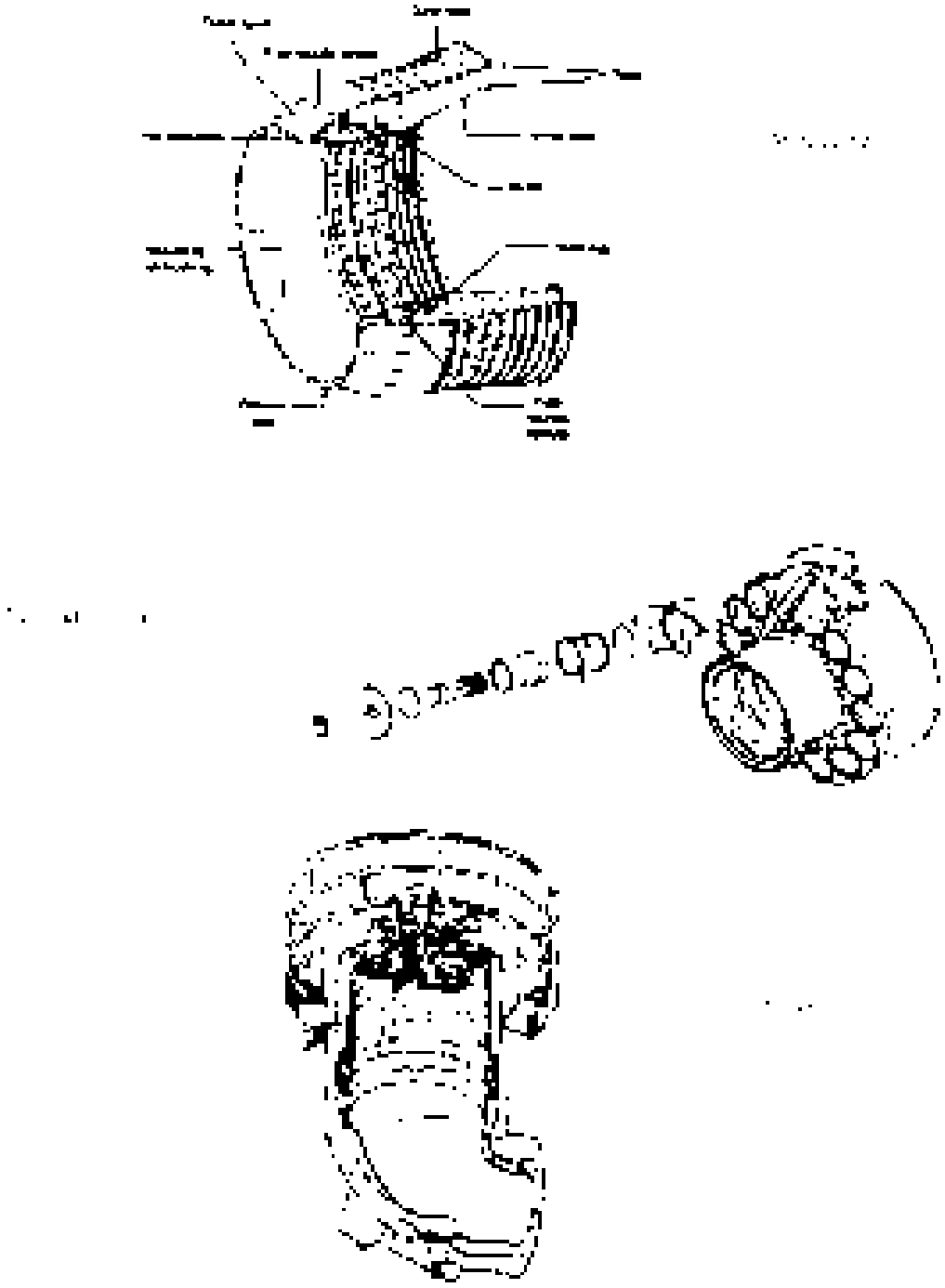
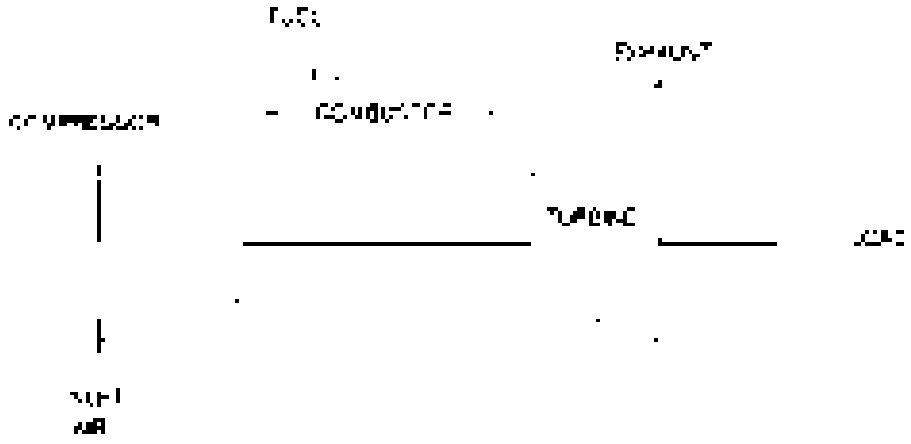


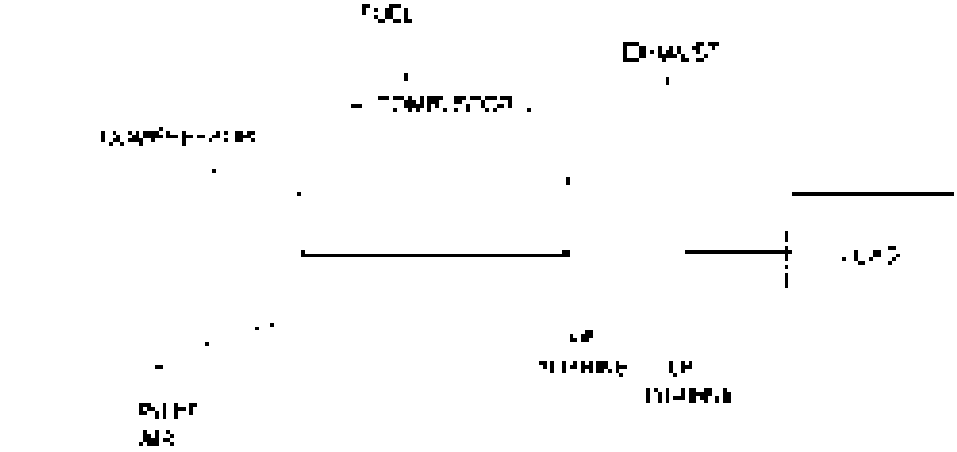
Figure 3-2. Types of gas turbine combustors.[3-5]

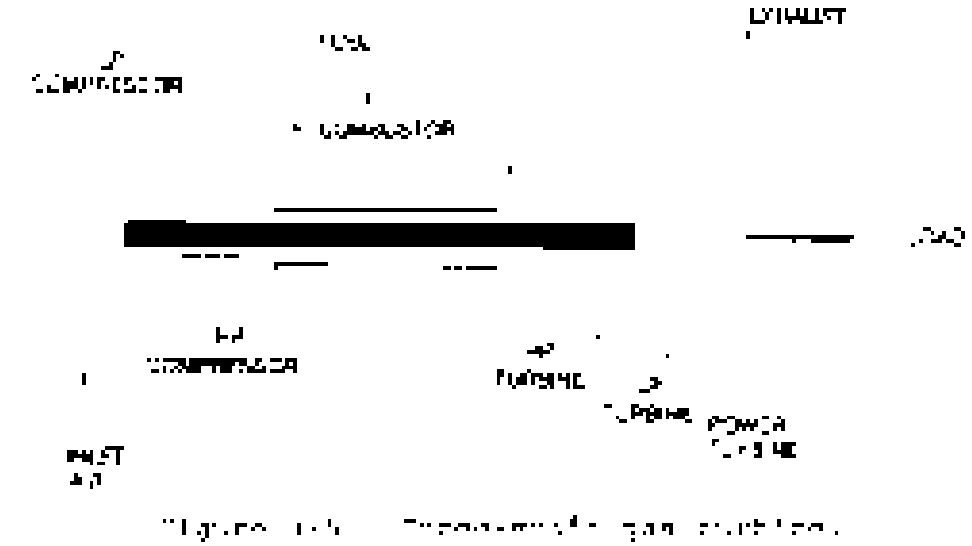
; further discussion of combustors is found in Chapter 5.[3-5] Flame temperatures in the combustor can reach 2000°C (3600°F).[6] The hot combustion gases

are then diluted with additional cool air from the compressor section and directed to the turbine section at temperatures up to 1285°C (2350°F).[6] Energy is recovered in the turbine section in the form of shaft horsepower, of which typically greater than 50 percent is required to drive the internal compressor section.[7] The balance of the recovered shaft energy is available to drive the external load unit.

The compressor and turbine sections can each be a single fan-like wheel assembly, or stage, but are usually made up of a series of stages. In a single-shaft gas turbine, shown in Figure 3-3







, all compressor and turbine stages are fixed to a single, continuous shaft and operate at the same speed. A single-shaft gas turbine is typically used to drive electric generators where there is little speed variation.

A two-shaft gas turbine is shown in Figure 3-4. In this design, the turbine section is divided into a high-pressure and low-pressure arrangement, where the high-pressure turbine is mechanically tied to the compressor section by one shaft, while the low-pressure turbine, or power turbine, has its own shaft and is connected to the external load unit. This configuration allows the high-pressure turbine/compressor shaft assembly, or rotor, to operate at or near optimum design speeds, while the power turbine rotor speed can vary over as wide a range as is required by most external-load units in mechanical drive applications (i.e., compressors and pumps).

A third configuration is a three-shaft gas turbine. As shown in Figure 3-5, the compressor section is divided into a low-pressure and high-pressure configuration. The low-pressure compressor stages are mechanically tied to the low-pressure turbine stages, and the high-pressure compressor stages are similarly connected to the high-pressure turbine stages in a concentric shaft arrangement. These low-pressure and high-pressure rotors operate at optimum design speeds independent of each other. The power turbine stages are mounted on a third independent shaft and form the power turbine rotor, the speed of

which can vary over as wide a range as is necessary for mechanical drive applications.

Gas turbines can burn a variety of fuels. Most burn natural gas, waste process gases, or liquid fuels such as distillate oils (primarily No. 2 fuel oil). Some gas turbines are capable of burning lower-grade residual or even crude oil with minimal processing. Coal-derived gases can be burned in some turbines.

The capacity of individual gas turbines ranges from approximately 0.08 to over 200 megawatts (MW) (107 to 268,000 horsepower [hp]).[2] Manufacturers continue to increase the horsepower of individual gas turbines, and frequently they are "ganged," or installed in groups so that the total horsepower output from one location can meet virtually any installation's power requirements.

Several characteristics of gas turbines make them attractive power sources. These characteristics include a high horsepower-to-size ratio, which allows for efficient space utilization, and a short time from order placement to on-line operation. Many suppliers offer the gas turbine, load unit, and all accessories as a fully assembled package that can be performance tested at the supplier's facility. This packaging is cost effective and saves substantial installation time. Other advantages of gas turbines are:

1. Low vibration;
2. High reliability;
3. No requirement for cooling water;
4. Suitability for remote operation;
5. Lower capital costs than reciprocating engines; and
6. Lower capital costs than boiler/steam turbine-based electric power generating plants.[8]

3.2 OPERATING CYCLES

The four basic operating cycles for gas turbines are simple, regenerative, cogeneration, and combined cycles. Each of these cycles is described separately below.

3.2.1 Simple Cycle

The simple cycle is the most basic operating cycle of a gas turbine. In a simple cycle application, a gas turbine functions with only the three primary sections described in Section 3.1, as depicted in Figure 3-6.

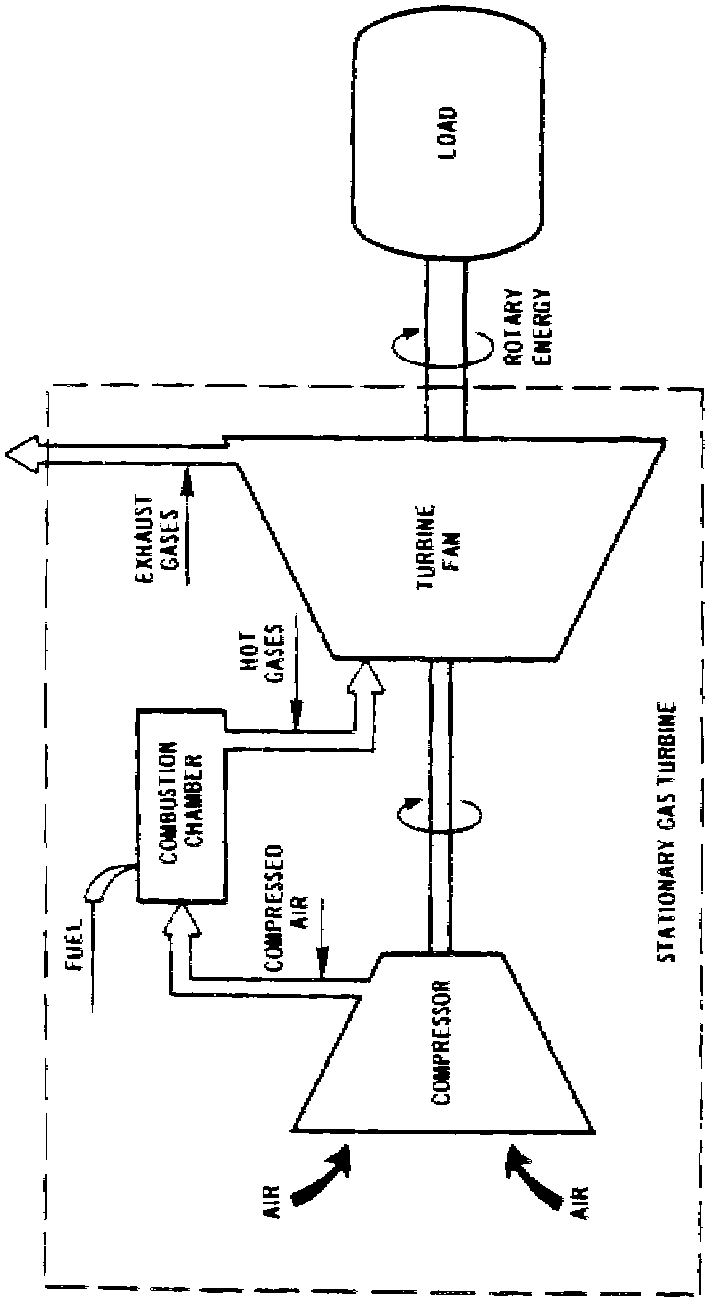


Figure 3-6. Simple cycle gas turbine appplication.[10]

[10] Cycle efficiency, defined as a percentage of useful shaft energy output to fuel energy input, is typically in the 30 to 35 percent range, although one manufacturer states an efficiency of 40 percent for an engine recently introduced to the market.[9] In addition to shaft energy output, 1 to 2 percent of the fuel input energy can be attributed to mechanical losses; the balance is exhausted from the turbine in the form of heat.[7] Simple cycle operation is typically used when there is a requirement for shaft horsepower without recovery of the exhaust heat. This cycle offers the lowest installed capital cost but also provides the least efficient use of fuel and therefore the highest operating cost.

3.2.2 Regenerative Cycle

The regenerative cycle gas turbine is essentially a simple cycle gas turbine with an added heat exchanger, called a regenerator or recuperator, to preheat the combustion air. In the regenerative cycle, thermal energy from the exhaust gases is transferred to the compressor discharge air prior to being introduced into the combustor. A diagram of this cycle is depicted in Figure 3-7

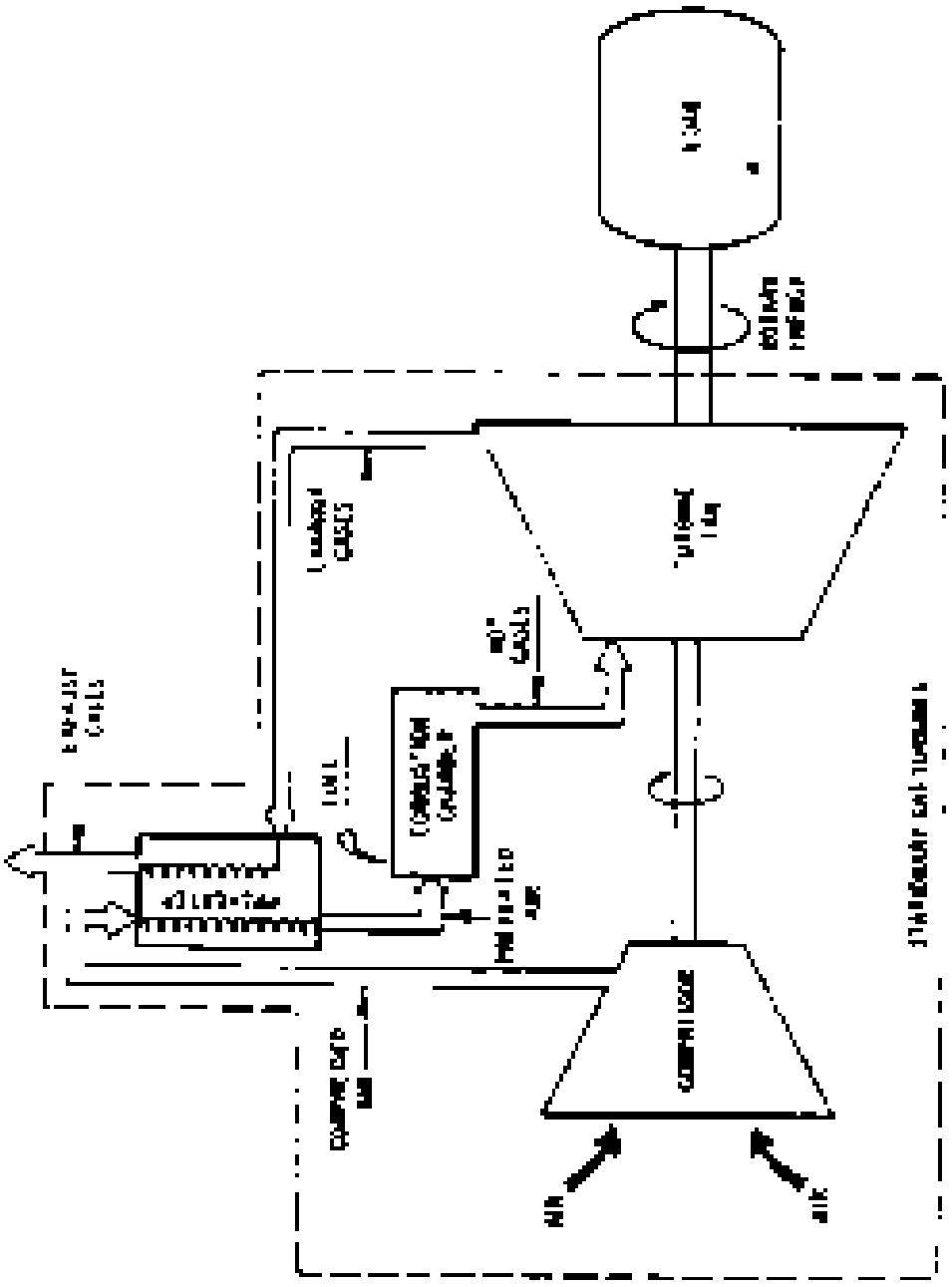


Figure 3-7. Regenerative cycle gas turbine.[11]

.[11] Preheating the combustion air reduces the amount of fuel required to reach design combustor temperatures and therefore improves the overall cycle efficiency over that of simple cycle operation. The efficiency gain is directly proportional to the differential temperature between the exhaust gases and compressor discharge air. Since the compressor discharge air temperature increases with an increase in pressure ratio, higher regenerative cycle efficiency gains are realized from lower compressor pressure ratios typically found in older gas turbine models.[7] Most new or updated gas turbine models with high compressor pressure ratios render regenerative cycle operation economically unattractive because the capital cost of the regenerator cannot be justified by the marginal fuel savings.

3.2.3 Cogeneration Cycle

A gas turbine used in a cogeneration cycle application is essentially a simple cycle gas turbine with an added exhaust heat exchanger, called a heat recovery steam generator (HRSG). This configuration is shown in Figure 3-8

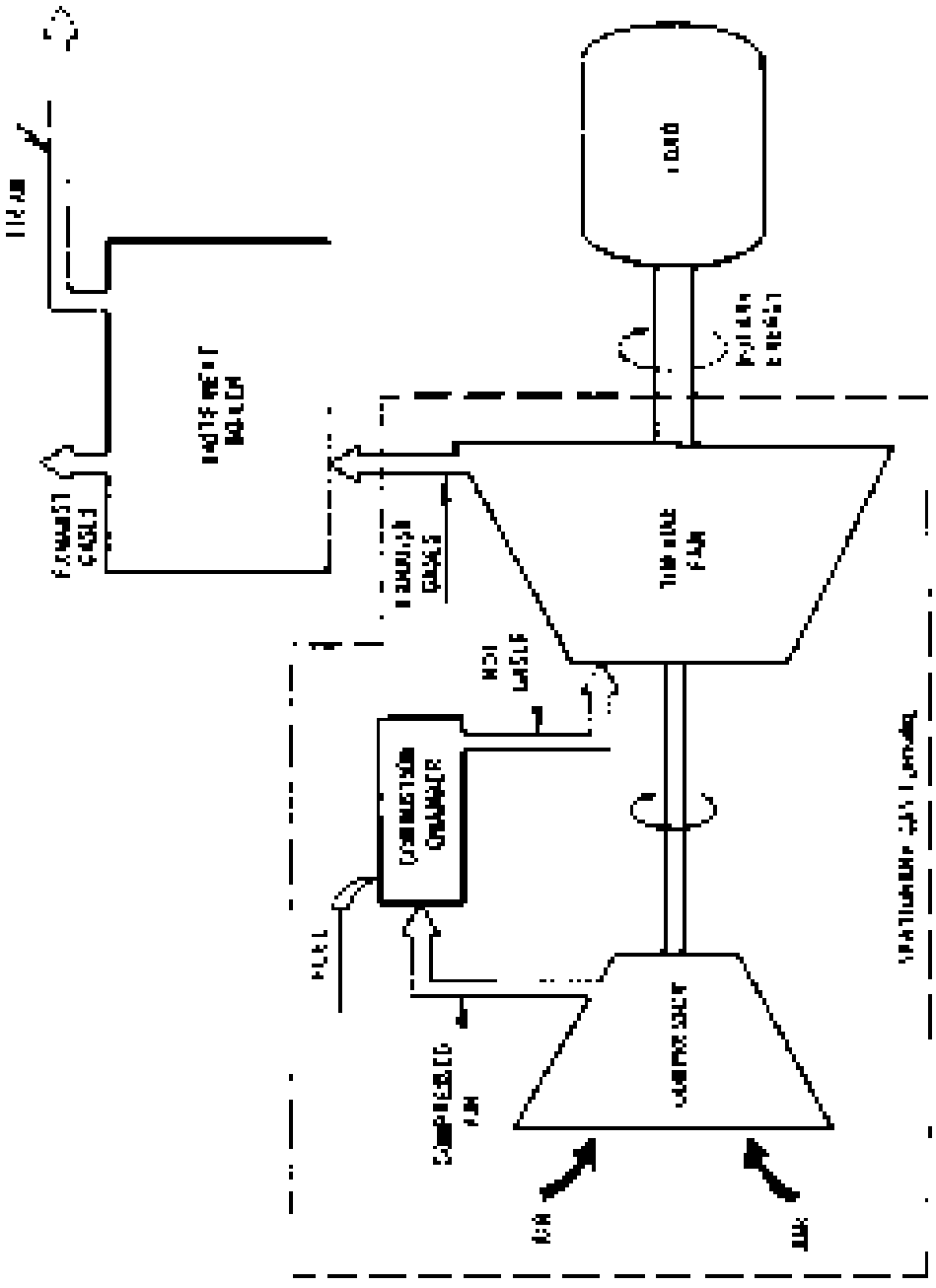


Figure 3-8. Cogeneration cycle gas turbine application.[12]

.[12] The steam generated by the exhaust heat can be delivered at a variety of pressure and temperature conditions to meet site thermal process requirements. Where the exhaust heat is not sufficient to meet site requirements, a supplementary burner, or duct burner, can be placed in the exhaust duct upstream of the HRSG to increase the exhaust heat energy. Adding the HRSG equipment increases the capital cost, but recovering the exhaust heat increases the overall cycle efficiency to as high as 75 percent.[13]

3.2.4 Combined Cycle

A combined cycle is the terminology commonly used for a gas turbine/HRSG configuration as applied at an electric utility. This cycle, shown in Figure 3-9

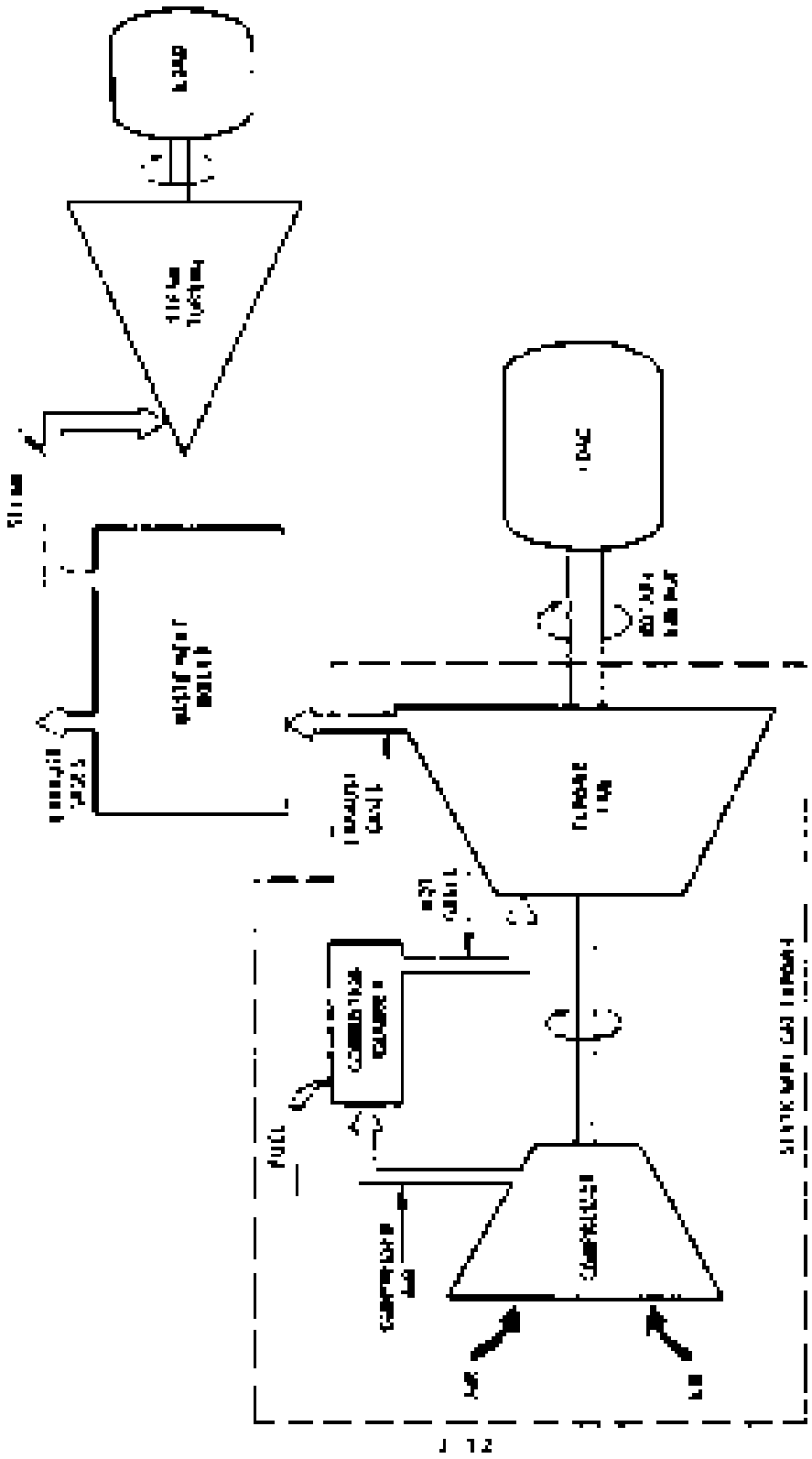


Figure 3-9. Combined cycle gas turbine application.[12]

, is used to generate electric power.[12] The gas turbine drives an electric generator, and the steam produced in the HRSG is delivered to a steam turbine, which also drives an electric generator. The boiler may be supplementary-fired to increase the steam production where desired. Cycle efficiencies can exceed 50 percent.

3.3 INDUSTRY APPLICATIONS

Gas turbines are used by industry in both mechanical and electrical drive applications. Compressors and pumps are most often the driven load unit in mechanical drive applications, and electric generators are driven in electrical drive installations. Few sites have gas/air compression or fluid pumping requirements that exceed 15 MW (20,100 hp), and for this reason mechanical drive applications generally use gas turbines in the 0.08- to 15.0-MW (107- to 20,100-hp) range.[14] Electric power requirements range over the entire available range of gas turbines, however, and all sizes can be found in electrical drive applications, from 0.08 to greater than 200 MW (107 to 268,000 hp).[15]

The primary applications for gas turbines can be divided into five broad categories: the oil and gas industry,

stand-by/emergency electric power generation, independent electric power producers, electric utilities, and other industrial applications.[16] Where a facility has a requirement for mechanical shaft power only, the installation is typically simple or regenerative cycle. For facilities where either electric power or mechanical shaft power and steam generation are required, the installation is often cogeneration or combined cycle to capitalize on these cycles' higher efficiencies.

3.3.1 Oil and Gas Industry

The bulk of mechanical drive applications are in the oil and gas industry. Gas turbines in the oil and gas industry are used primarily to provide shaft horsepower for oil and gas extraction and transmission equipment, although they are also used in downstream refinery operations. Most gas turbines found in this industry are in the 0.08- to 15.0-MW (107- to 20,100-hp) range.

Gas turbines are particularly well suited to this industry, as they can be fueled by a wide range of gaseous and liquid fuels often available at the site. Natural gas and distillate oil are the most common fuels. Many turbines can burn waste process gases, and some turbines can burn residual oils and even crude oil. In addition, gas turbines are suitable for remote installation sites and unattended operation. Most turbines used in this industry operate continuously, 8,000+ hours per year, unless the installation is a pipeline transmission application with seasonal operation.

Competition from reciprocating engines in this industry is significant. Although gas turbines have a considerable capital cost advantage, reciprocating engines require less fuel to produce the same horsepower and consequently have a lower operating cost.[17] Selection of gas turbines vs. reciprocating engines is generally determined by site-specific criteria such as installed capital costs, costs for any required emissions control equipment, fuel costs and availability, annual operating hours, installation and structural considerations, compatibility with existing equipment, and operating experience.

3.3.2 Stand-By/Emergency Electric Power Generation

Small electric generator sets make up a considerable number of all gas turbine sales under 3.7 MW (5,000 hp). The majority of these installations provide backup or emergency power to critical networks or equipment and use liquid fuel. Telephone companies are a principal user, and hospitals and small municipalities also are included in this market. These turbines operate on an as-needed basis, which typically is between 75 and 200 hours per year.

Gas turbines offer reliable starting, low weight, small size, low vibration, and relatively low maintenance, which are important criteria for this application. Gas turbines in this size range have a relatively high capital cost, however, and reciprocating engines dominate this market, especially for applications under 2,000 kW (2,700 hp).[18,19]

3.3.3 Independent Electrical Power Producers

Large industrial complexes and refining facilities consume considerable amounts of electricity, and many sites choose to generate their own power. Gas turbines can be used to drive electric generators in simple cycle operation, or an HRSG system may be added to yield a more efficient cogeneration cycle. The vast majority of cogeneration installations operate in a combined cycle capacity, using a steam turbine to provide additional electric power. The Public Utility Regulatory Policies Act (PURPA) of 1978 encourages independent cogenerators to generate electric power by requiring electric utilities to (1) purchase electricity from qualifying producers at a price equal to the cost the utility can avoid by not having to otherwise supply that power (avoided cost) and (2) provide backup power to the cogenerator at reasonable rates. Between 1980 and 1986, approximately 20,000 MW of gas turbine-produced electrical generating capacity was certified as qualifying for PURPA benefits. This installed capacity by private industry power generators is more than the sum of all utility gas turbine orders for all types of central power plants during this period.[20] The Department of Energy (DOE) expects an additional 27,000 MW

capacity to be purchased by private industry in the next 10 years.[21]

Gas turbines installed in this market range in power from 1 to over 100 MW (1,340 to 134,000 hp) and operate typically between 4,000 and 8,000 hours per year. While reciprocating engines compete with the gas turbine at the lower end of this market (under approximately 7.5 MW [10,000 hp]), the advantages of lower installed costs, high reliability, and low maintenance requirements make gas turbines a strong competitor.

3.3.4 Electric Utilities

Electric utilities are the largest user of gas turbines on an installed horsepower basis. They have traditionally installed these turbines for use as peaking units to meet the electric power demand peaks typically imposed by large commercial and industrial users on a daily or seasonal basis; consequently, gas turbines in this application operate less than 2,000 hours per year.[22] The power range used by the utility market is 15 MW to over 150 MW (20,100 to 201,000 hp). Peaking units typically operate in simple cycle.

The demand for gas turbines from the utility market was flat through the late 1970's and 1980's as the cost of fuel increased and the supplies of gas and oil became unpredictable. There are signs, however, that the utility market is poised to again purchase considerable generating capacity. The capacity margin, which is the utility industry's measure of excess generation capacity, peaked at 30 percent in 1982. By 1990, the capacity margin had dropped to approximately 20 percent, and, based on current construction plans, will reach the industry rule-of-thumb minimum of 15 percent by 1995.[21] The utility industry is adding new capacity and repowering existing older plants, and gas turbines are expected to play a considerable role.

Many utilities are now installing gas turbine-based combined cycle installations with provisions for burning coal-derived gas fuel at some future date. This application is known as integrated coal gasification combined cycle (IGCC). At least five power plant projects have been announced, and several more

are being negotiated. Capital costs for these plants are in many cases higher than comparable natural gas-fueled applications, but future price increases for natural gas could make IGCC an attractive option for the future.[23]

Utility orders for gas turbines have doubled in each of the last 2 years. The DOE says that electric utilities will need to add an additional 73,000 MW to capacity to meet demand by the year 2000, and as Figure 3-10

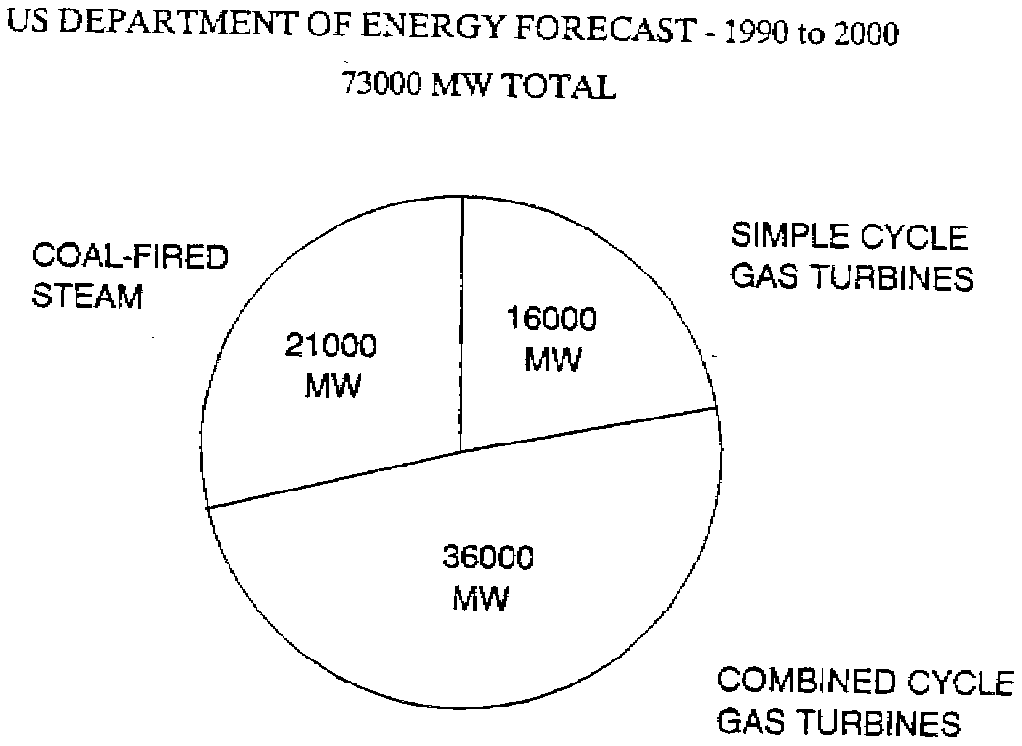


Figure 3-10. Total capacity to be purchased by the utility industry.[21]

shows, DOE expects 36,000 MW of combined cycle and 16,000 MW of simple cycle gas turbines to be purchased. This renewed interest in gas turbines is a result of:

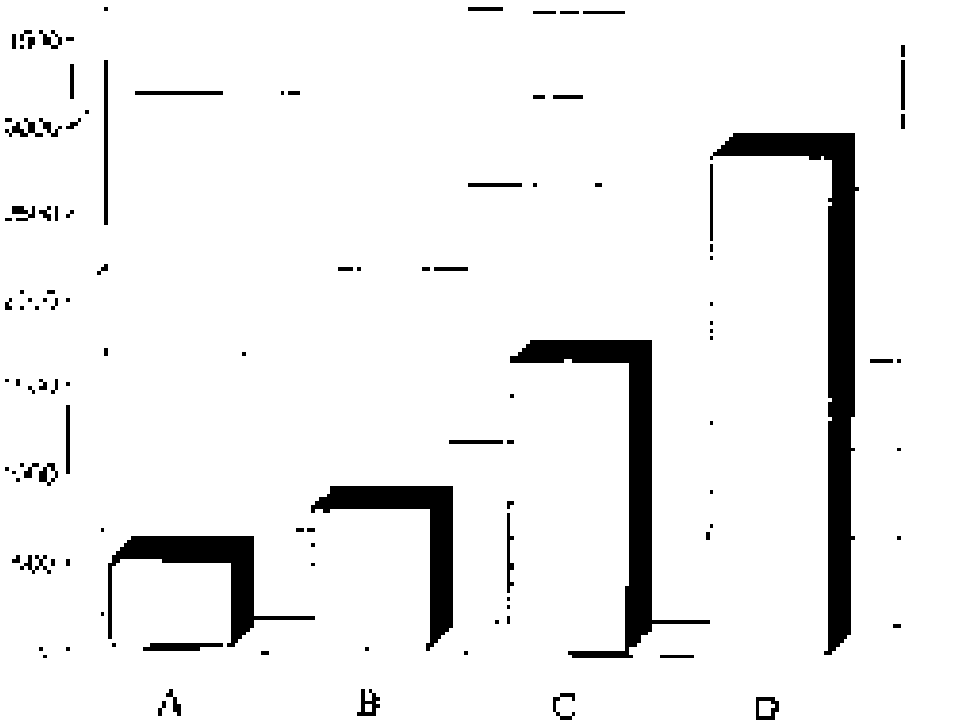
1. The introduction of new, larger, more efficient gas turbines;

2. Lower natural gas prices and proven reserves to meet current demand levels for more than 100 years;

3. Shorter lead times than those of competing equipment; and

4. Lower capital costs for gas turbines.[21]

Utility capital cost estimates, as shown in Figure 3-11



A - Repower existing plant using combined cycle gas turbines
B - New plant using combined cycle gas turbines
C - New plant using coal fired boilers
D - New plant using nuclear power

Figure 3-11. Capital costs for electric utility plants.[24]

, are (1) $500 per KW for repowering existing plants with combined cycle gas turbines, (2) $800 per KW for new combined cycle plants, (3) $1,650 per KW for new coal-fired plants, and (4) $2,850 per KW for new nuclear-powered plants.[24]

Gas turbines are also an alternative to displace planned or existing nuclear facilities. A total of 1,020 MW of gas turbine-generated electric power was recently commissioned in Michigan at a plant where initial design and construction had begun for a nuclear plant. Four additional idle nuclear sites are considering switching to gas turbine-based power production due to the legal, regulatory, financial, and public obstacles facing nuclear facilities.[24]

3.3.5 Other Industrial Applications

Industrial applications for gas turbines include various types of mechanical drive and air compression equipment. These applications peaked in the late 1960's and declined through the 1970's.[25] With the promulgation of PURPA in 1978 (see Section 3.3.3), many industrial facilities have found it

economically feasible to install a combined cycle gas turbine to meet power and steam requirements. Review of editions of Gas Turbine World over the last several years shows that a broad range of industries (e.g., pulp and paper, chemical, and food processing) have installed combined cycle gas turbines to meet their energy requirements.

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4.0 CHARACTERIZATION OF NO_x EMISSIONS

This section presents the principles of NO_x formation, the types of NO_x emitted (i.e., thermal NO_x, prompt NO_x, and fuel NO_x), and how they are generated in a gas turbine combustion process. Estimated NO_x emission factors for gas turbines and the bases for the estimates are also presented.

4.1 THE FORMATION OF NO_x

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of nitrogen (N_2) and oxygen (O_2) into N and O, respectively. Reactions following this dissociation result in seven known oxides of nitrogen: NO, NO_2, NO_3, N_2O, N_2O_3, N_2O_4, and N_2O_5. Of these, nitric oxide (NO) and nitrogen dioxide (NO_2) are formed in sufficient quantities to be significant in atmospheric pollution.[1] In this document, "NO_x" refers to either or both of these gaseous oxides of nitrogen.

Virtually all NO_x emissions originate as NO. This NO is further oxidized in the exhaust system or later in the atmosphere to form the more stable NO_2 molecule.[2] There are two mechanisms by which NO_x is formed in turbine combustors: (1) the oxidation of atmospheric nitrogen found in the combustion air (thermal NO_x and prompt NO_x) and (2) the conversion of nitrogen chemically bound in the fuel (fuel NO_x). These mechanisms are discussed below.

4.1.1 Formation of Thermal and Prompt NO_x

Thermal NO_x is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form oxides of nitrogen.

The major contributing chemical reactions are known as the Zeldovich mechanism and take place in the high temperature area of the gas turbine combustor.[3] Simply stated, the Zeldovich mechanism postulates that thermal NO_x formation increases exponentially with increases in temperature and linearly with increases in residence time.[4]

Flame temperature is dependent upon the equivalence ratio, which is the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.[5] An equivalence ratio of 1.0 corresponds to the stoichiometric ratio and is the point at which a flame burns at its highest theoretical temperature.[5] Figure 4-1

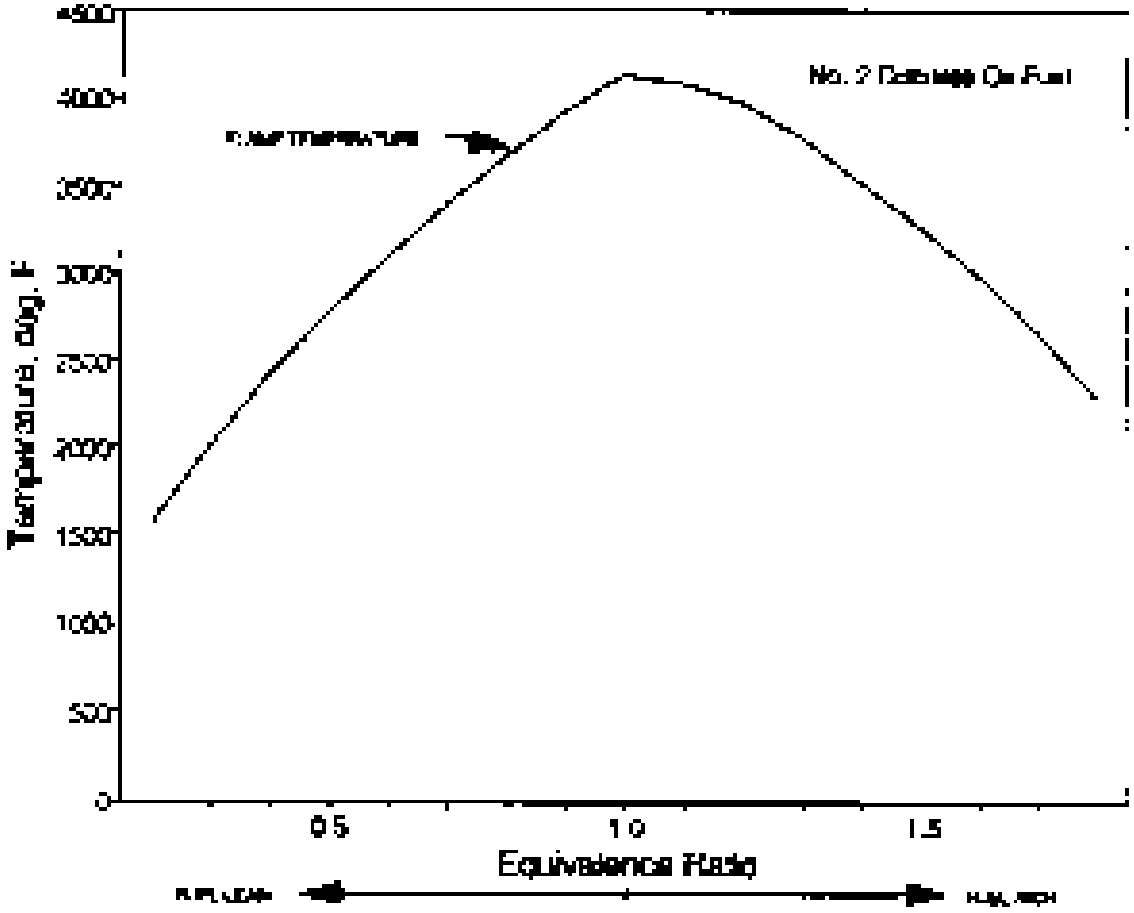


Figure 4-1. Influence of equivalence ratio on flame temperature.[4]

shows the flame temperature and equivalence ratio relationship for combustion using No. 2 distillate fuel oil (DF-2).[4]

The series of chemical reactions that form thermal NO_x according to the Zeldovich mechanism are presented below.[3]

1. $O_2 \rightleftharpoons 2O$;

2. $N_2 \rightleftharpoons 2N$;

3. $N + O \rightleftharpoons NO$;

4. $N + O_2 \rightleftharpoons NO + O$; and

5. $O + N_2 \rightleftharpoons NO + N$.

This series of equations applies to a fuel-lean combustion process. Combustion is said to be fuel-lean when there is excess oxygen available (equivalence ratio <1.0). Conversely, combustion is fuel-rich if insufficient oxygen is present to burn all of the available fuel (equivalence ratio >1.0). Additional equations have been developed that apply to fuel-rich combustion. These equations are an expansion of the above series to add an intermediate hydroxide molecule (OH):[3]

6. $N + OH \rightleftharpoons NO + H$,

and further to include an intermediate product, hydrogen cyanide (HCN), in the formation process:[3]

7. $N_2 + CH \rightleftharpoons HCN + N$ and

8. $N + OH \rightleftharpoons H + NO$.

The overall equivalence ratio for gases exiting the gas turbine combustor is less than 1.0.[4] Fuel-rich areas do exist in the overall fuel-lean environment, however, due to less-than-ideal fuel/air mixing prior to combustion. This being the case, the above equations for both fuel-lean and fuel-rich combustion apply for thermal NO_x formation in gas turbines.

Prompt NO_x is formed in the proximity of the flame front as intermediate combustion products such as HCN, N, and NH are oxidized to form NO_x as shown in the following equations:

1. $CH + N_2 \rightleftharpoons HCN + N$;

2. $CH_2 + N_2 \rightleftharpoons HCN + NH$; and

3. $HCN, N, NH + O_x \rightleftharpoons NO + ...$[6]

Prompt NO_x is formed in both fuel-rich flame zones and fuel-lean premixed combustion zones. The contribution of prompt NO_x to overall NO_x emissions is relatively small in conventional near-stoichiometric combustors, but this contribution increases with decreases in the equivalence ratio (fuel-lean mixtures). For this reason, prompt NO_x becomes an important consideration for the low-NO_x combustor designs described in Chapter 5 and establishes a minimum NO_x level attainable in lean mixtures.[7]

4.1.2 Formation of Fuel NO_x

Fuel NO_x (also known as organic NO_x) is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as

N_2 in some natural gas, does not contribute significantly to fuel NO_x formation.[8] However, nitrogen compounds are present in coal and petroleum fuels as pyridine-like (C_5H_5N) structures that tend to concentrate in the heavy resin and asphalt fractions upon distillation. Some low-British thermal unit (Btu) synthetic fuels contain nitrogen in the form of ammonia (NH_3), and other low-Btu fuels such as sewage and process waste-stream gases also contain nitrogen. When these fuels are burned, the nitrogen bonds break and some of the resulting free nitrogen oxidizes to form NO_x.[9] With excess air, the degree of fuel NO_x formation is primarily a function of the nitrogen content in the fuel. The fraction of fuel-bound nitrogen (FBN) converted to fuel NO_x decreases with increasing nitrogen content, although the absolute magnitude of fuel NO_x increases. For example, a fuel with 0.01 percent nitrogen may have 100 percent of its FBN converted to fuel NO_x, whereas a fuel with a 1.0 percent FBN may have only a 40 percent fuel NO_x conversion rate. The low-percentage FBN fuel has a 100 percent conversion rate, but its overall NO_x emission level would be lower than that of the high-percentage FBN fuel with a 40 percent conversion rate.[10]

Nitrogen content varies from 0.1 to 0.5 percent in most residual oils and from 0.5 to 2 percent for most U.S. coals.[11] Traditionally, most light distillate oils have had less than 0.015 percent nitrogen content by weight. However, today many distillate oils are produced from poorer-quality crudes, especially in the northeastern United States, and these distillate oils may contain percentages of nitrogen exceeding the 0.015 threshold; this higher nitrogen content can increase fuel NO_x formation.[4] At least one gas turbine installation burning coal-derived fuel is in commercial operation in the United States.[12]

Most gas turbines that operate in a continuous duty cycle are fueled by natural gas that typically contains little or no FBN. As a result, when compared to thermal NO_x, fuel NO_x is not

currently a major contributor to overall NO_x emissions from stationary gas turbines.

4.2 UNCONTROLLED NO_x EMISSIONS

The NO_x emissions from gas turbines are generated entirely in the combustor section and are released into the atmosphere via the stack. In the case of simple and regenerative cycle operation, the combustor is the only source of NO_x emissions. In cogeneration and combined cycle applications, a duct burner may be placed in the exhaust ducting between the gas turbine and the heat recovery steam generator (HRSG); this burner also generates NO_x emissions. (Gas turbine operating cycles are discussed in Section 3.2.) The amount of NO_x formed in the combustion zone is "frozen" at this level regardless of any temperature reductions that occur at the downstream end of the combustor and is released to the atmosphere at this level.[1]

4.2.1 Parameters Influencing Uncontrolled NO_x Emissions

The level of NO_x formation in a gas turbine, and hence the NO_x emissions, is unique (by design factors) to each gas turbine model and operating mode. The primary factors that determine the amount of NO_x generated are the combustor design, the types of fuel being burned, ambient conditions, operating cycles, and the power output level as a percentage of the rated full power output of the turbine. These factors are discussed below.

4.2.1.1 Combustor Design. The design of the combustor is the most important factor influencing the formation of NO_x. Design considerations are presented here and discussed further in Chapter 5.

Thermal NO_x formation, as discussed in Section 4.1.1, is influenced primarily by flame temperature and residence time. Design parameters controlling equivalence ratios and the introduction of cooling air into the combustor strongly influence thermal NO_x formation. The extent of fuel/air mixing prior to combustion also affects NO_x formation. Simultaneous mixing and combustion results in localized fuel-rich zones that yield high flame temperatures in which substantial thermal NO_x production

takes place.[13] The dependence of thermal NO_x formation on flame temperature and equivalence ratio is shown in Figure 4-2

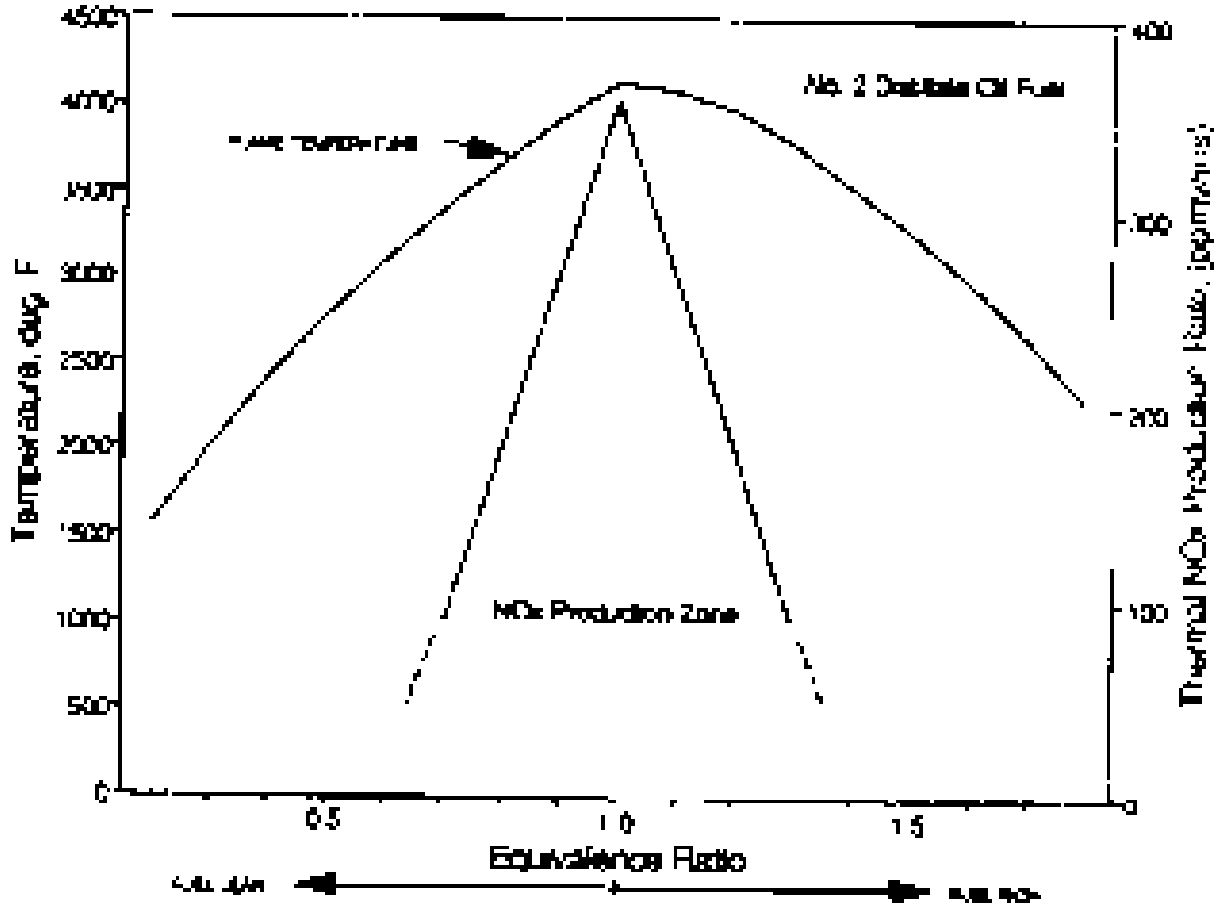


Figure 4-2. Thermal NO_x production as a function of flame temperature and equivalence ratio.[4]

for DF-2.[4] Conversely, prompt NO_x is largely insensitive to changes in temperature and pressure.[7]

Fuel NO_x formation, as discussed in Section 4.1.2, is formed when FBN is released during combustion and oxidizes to form NO_x. Design parameters that control equivalence ratio and residence time influence fuel NO_x formation.[14]

4.2.1.2 Type of Fuel. The level of NO_x emissions varies for different fuels. In the case of thermal NO_x, this level increases with flame temperature. For gaseous fuels, the constituents in the gas can significantly affect NO_x emissions levels. Gaseous fuel mixtures containing hydrocarbons with molecular weights higher than that of methane (e.g., ethane, propane, and butane) burn at higher flame temperatures and as a result can increase NO_x emissions greater than 50 percent over NO_x levels for methane gas fuel. Refinery gases and some unprocessed field gases contain significant levels of these higher molecular weight hydrocarbons. Conversely, gas fuels that contain significant inert gases, such as CO_2, generally produce lower NO_x emissions. These inert gases serve to absorb heat during combustion, thereby lowering flame temperatures and reducing NO_x emissions. Examples of this type of gas fuel are air-blown gasifier fuels and some field gases.[15] Combustion of hydrogen also results in high flame temperatures, and gases with significant hydrogen content produce relatively high NO_x emissions. Refinery gases can have hydrogen contents exceeding 50 percent.[16]

As is shown in Figure 4-3

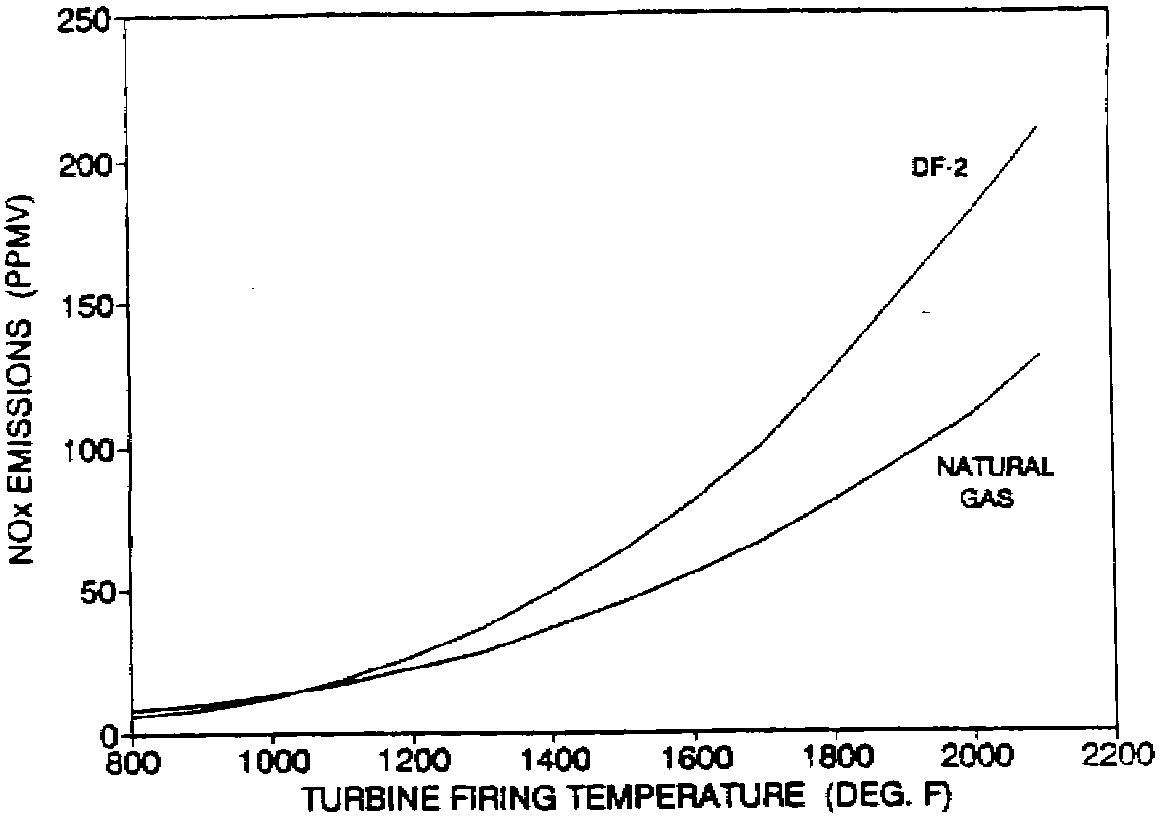


Figure 4-3. Influence of firing temperature on thermal NO_x formation.[17]

, DF-2 burns at a flame temperature that is approximately 75°C (100°F) higher than that of natural gas, and as a result, NO_x emissions are higher when burning DF-2 than they are when burning natural gas.[17] Low-Btu fuels such as coal gas burn with lower flame temperatures, which result in

substantially lower thermal NO_x emissions than natural gas or DF-2.[18] For fuels containing FBN, the fuel NO_x production increases with increasing levels of FBN.

4.2.1.3 Ambient Conditions. Ambient conditions that affect NO_x formation are humidity, temperature, and pressure. Of these ambient conditions, humidity has the greatest effect on NO_x formation.[19] The energy required to heat the airborne water vapor has a quenching effect on combustion temperatures, which reduces thermal NO_x formation. At low humidity levels, NO_x emissions increase with increases in ambient temperature. At high humidity levels, the effect of changes in ambient temperature on NO_x formation varies. At high humidity levels and low ambient temperatures, NO_x emissions increase with increasing temperature. Conversely, at high humidity levels and ambient temperatures above 10°C (50°F), NO_x emissions decrease with increasing temperature.

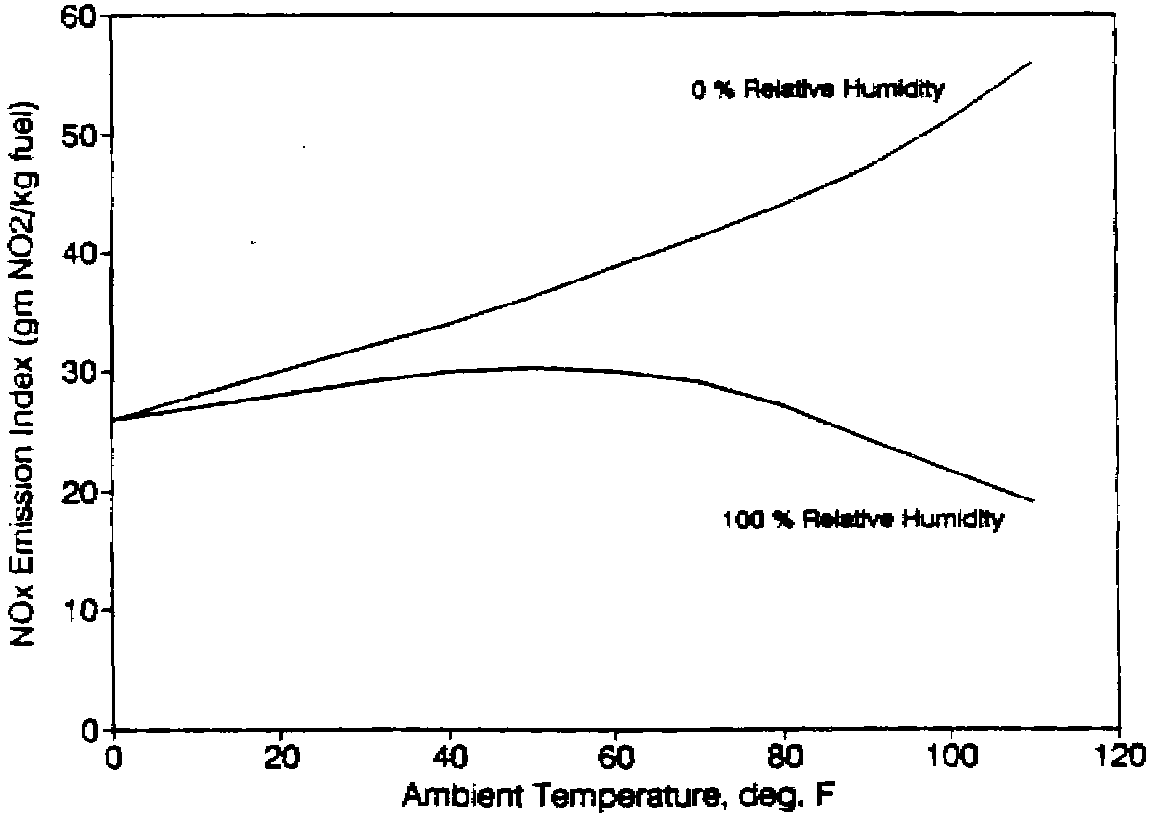


Figure 4-4. Influence of relative humidity and ambient temperature on NO_x formation.[19]

This effect of humidity and temperature on NO_x formation is shown in Figure 4-4. A rise in ambient pressure results in higher pressure and temperature levels entering the combustor and so No_x production levels increase with increases in ambient pressure.[19]

The influence of ambient conditions on measured NO_x emission levels can be corrected using the following equation:[20]

$$NO_x = (NO_{xo})(P_r/P_o)^{0.5} e^{19(Ho-0.00633)} (288°K/T_a)^{1.53}$$

where:

NO_x = emission rate of NO_x at 15 percent O_2 and International Standards Organization (ISO) ambient conditions, volume percent;

NO_{xo} = observed NO_x concentration, parts per million by volume (ppmv) referenced to 15 percent O_2;

P_r = reference compressor inlet absolute pressure at 101.3 kilopascals ambient pressure, millimeters mercury (mm Hg);

P_o = observed compressor inlet absolute pressure at test, mm Hg;

H_o = observed humidity of ambient air, g H_2O/g air;

e = transcendental constant, 2.718; and

T_a = ambient temperature, K.

At least two manufacturers state that this equation does not accurately correct NO_x emissions for their turbine models.[8,12] It is expected that these turbine manufacturers could provide corrections to this equation that would more accurately correct NO_x emissions for the effects of ambient conditions based on test data for their turbine models.

4.2.1.4 Operating Cycles. Emissions from identical turbines used in simple and cogeneration cycles have similar NO_x emissions levels, provided no duct burner is used in heat recovery applications. The NO_x emissions are similar because, as stated in Section 4.2, NO_x is formed only in the turbine combustor and remains at this level regardless of downstream temperature reductions. A turbine operated in a regenerative cycle produces higher NO_x levels, however, due to increased combustor inlet temperatures present in regenerative cycle applications.[21]

4.2.1.5 Power Output Level. The power output level of a gas turbine is directly related to the firing temperature, which is directly related to flame temperature. Each gas turbine has a base-rated power level and corresponding NO_x level. At power outputs below this base-rated level, the flame temperature is lower, so NO_x emissions are lower. Conversely, at peak power outputs above the base rating, NO_x emissions are higher due to higher flame temperature. The NO_x emissions for a range of firing temperatures are shown in Figure 4-3 for one manufacturer's gas turbine.[17]

4.2.2 NO_x Emissions From Duct Burners

In some cogeneration and combined cycle applications, the exhaust heat from the gas turbine is not sufficient to produce the desired quantity of steam from the HRSG, and a supplemental burner, or duct burner, is placed in the exhaust duct between the gas turbine and HRSG to increase temperatures to sufficient

levels. In addition to providing additional steam capacity, this burner also increases the overall system efficiency since essentially all energy added by the duct burner can be recovered in the HRSG.[22]

The level of NO_x produced by a duct burner is approximately 0.1 pound per million Btu (lb/MMBtu) of fuel burned. The ppmv level depends upon the flowrate of gas turbine exhaust gases in which the duct burner is operating and thus varies with the size of the turbine.[23]

Typical NO_x production levels added by a duct burner operating on natural gas fuel are:[23]

Gas turbine output, megawatts (MW)	Duct burner NO_x, ppmv, referenced to 15 percent O_2
3 to 50	10 to 30
50+	5 to 10

4.3 UNCONTROLLED EMISSION FACTORS

TABLE 4-1. UNCONTROLLED NO_x EMISSIONS FACTORS FOR GAS TURBINES AND DUCT BURNERS[8,12,15,24-29]

Manufacturer	Model No.	Output, MW	NO_x emissions, ppmv, dry and corrected to 15% O_2		NO_x emissions factor, lb NO_x/MMBtu[a]	
			Natural gas	Distillate oil No. 2	Natural gas	Distillate oil No. 2
Solar	Saturn	1.1	99	150	0.397	0.551
	Centaur	3.3	130	179	0.521	0.658
	Centaur "H"	4.0	105	160	0.421	0.588
	Taurus	4.5	114	168	0.457	0.618
	Mars T12000	8.8	178	267	0.714	0.981
	Mars T14000	10.0	199	NA[b]	0.798	NA[b]
GM/Allison	501-KB5	4.0	155	231	0.622	0.849
	570-KA	4.9	101	182	0.405	0.669
	571-KA	5.9	101	182	0.405	0.669
General Electric	LM1600	12.8	144	237	0.577	0.871
	LM2500	21.8	174	345	0.698	1.27
	LM5000	33.1	185	364	0.742	1.34
	LM6000	41.5	220	417	0.882	1.53
	MS5001P	26.3	142	211	0.569	0.776
	MS6001B	38.3	148	267	0.593	0.981
	MS7001EA	83.5	154	228	0.618	0.838
	MS7001F	123	179	277	0.718	1.02
	MS9001EA	150	176	235	0.706	0.864
	MS9001F	212	176	272	0.706	1.00
Asea Brown Boveri	GT8	47.4	430	680	1.72	2.50
	GT10	22.6	150	200	0.601	0.735
	GT11N	81.6	390	560	1.56	2.06
	GT35	16.9	300	360	1.20	1.32
Westinghouse	W261B11/12	52.3	220	355	0.882	1.31
	W501D5	119	190	250	0.762	0.919
Siemens	V84.2	105	212	360	0.850	1.32
	V94.2	153	212	360	0.850	1.32
	V64.3	61.5	380	530	1.52	1.95
	V84.3	141	380	530	1.52	1.95
	V94.3	203	380	530	1.52	1.95
Duct burners	All	NA[c]	≤30	NA[b]	<0.100[d]	NA[b]

[a]Based on emission levels provided by gas turbine manufacturers, corresponding to rated load at ISO conditions. NO_x emissions calculations are shown in Appendix A.

[b]Not available.

[c]Not applicable.

[d]References 16 and 22.

Uncontrolled emission factors are presented in Table 4-1. These factors are based on uncontrolled emission levels provided by manufacturers in ppmv, dry, and corrected to 15 percent O_2, corresponding to 100 percent output load and International Standards Organization (ISO) conditions of 15°C (59°F) and 1 atmosphere (14.7 psia). Sample calculations are given in Appendix A. The uncontrolled emissions factors range from 0.397 to 1.72 lb/MMBtu (99 to 430 ppmv) for natural gas and 0.551 to 2.50 lb/MMBtu (150 to 680 ppmv) for DF-2.

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27. Letters and attachments from Swingle, R., Solar Turbines Incorporated, to Snyder, R.B., MRI. February 1991. Response to gas turbine questionnaire.

28. Letters and attachments from Kimsey, D.L., Allison Gas Turbine Division of General Motors, to Snyder, R.B., MRI. February 1991. Response to gas turbine questionnaire.

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5.0 NO_x CONTROL TECHNIQUES

Nationwide NO_x emission limits have been established for stationary gas turbines in the new source performance standards (NSPS) promulgated in 1979.[1] This standard, summarized in Table 5-1

TABLE 5-1. NO_x EMISSION LIMITS AS ESTABLISHED BY THE NEW SOURCE PERFORMANCE STANDARDS FOR GAS TURBINES[1]

Fuel input MMBtu/hr	Size, MW	Application(s)	NO_x limit, ppmv at 15% O_2, dry[a] [b]
<10	1[c]	All	None
10-100	1-10[c]	All	150
>100	10+[c] <30[c] >30[c]	Utility[d] Nonutility Nonutility	75 150 None
<100	10[c]	Regenerative cycle	None
All	All	e	None

[a]Based on thermal efficiency of 25 percent. This limit may be increased for higher efficiencies by multiplying the limit in the table by 14.4/actual heat rate, in kJ/watt-hr.

[b]A fuel-bound nitrogen allowance may be added to the limits listed in the table according to the table listed below:

Fuel-bound nitrogen (N), percent by weight	Allowable increase, ppmv
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	400 x N
$0.1 < N \leq 0.25$	40 + [6.7 x (N - 0.1)]
$N > 0.25$	50

[c]Based on gas turbine heat rate of 10,000 Btu/kW-hr.

[d]An installation is considered a utility if more than 1/3 of its potential electrical output is sold.

[e]Emergency/stand-by, military (except garrison facilities), military training, research and development, firefighting, and emergency fuel operation applications are exempt from NO_x emission limits.

, effectively sets a limit for new, modified, or reconstructed gas turbines greater than 10.7 gigajoules per hour (approximately 3,800 horsepower [hp]) of 75 or 150 parts per million by volume (ppmv), corrected to 15 percent oxygen (O_2) on a dry basis, depending upon the size and application of the turbine. State and regional regulatory agencies may set more restrictive limits, and two organizations have established limits as low as 9 ppmv: the South Coast Air Quality Management District (SCAQMD) has defined limits as listed in Table 5-2

TABLE 5-2. NO_x COMPLIANCE LIMITS AS ESTABLISHED BY THE SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT (SCAQMD) FOR EXISTING TURBINES. RULE 1134. ADOPTED AUGUST 1989.[a,2]

Unit size, megawatt rating (MW)	NO_x limit, ppmv, 15% O_2 dry[b]
0.3 to <2.9 MW	25
2.9 to <10.0 MW	9
2.9 to <10.0 MW No SCR	15
10.0 MW and over	9
10.0 MW and over No SCR	12
60 MW and over Combined cycle No SCR	15
60 MW and over Combined cycle	9
Compliance limit = Reference limit X EFF/25 percent	
where: $EFF = \frac{3,413 \times 100\%}{\text{Actual heat rate at HHV of fuel (Btu/kW-hr)}}$ or EFF^c = (Manufacturer's rated efficiency at LHV) x $\frac{LHV}{HHV}$	

[a]The NO_x reference limits to be effective by December 31, 1995.
[b]Averaged over 15 consecutive minutes.
[c]EFF = the demonstrated percent efficiency of the gas turbine only as calculated without consideration of any down-stream energy recovery from the actual heat rate (Btu/kW-hr), or 1.34 (Btu/hp-hr); corrected to the higher heating value (HHV) of the fuel and ISO conditions, as measured at peak load for that facility; or the manufacturer's continuous rated percent efficiency (manufacturer's rated efficiency) of the gas turbine after correction from lower heating value (LHV) to the HHV of the fuel, whichever efficiency is higher. The value of EFF shall not be less than 25 percent. Gas turbines with lower efficiencies will be assigned a 25 percent efficiency for this calculation.

; and the Northeast States for Coordinated Air Use Management (NESCAUM) has recommended limits as listed in Table 5-3.

TABLE 5-3. NO_x EMISSION LIMITS RECOMMENDED BY THE NORTHEAST STATES FOR COORDINATED AIR USE MANAGEMENT (NESCAUM)

NEW TURBINES[3]

Fuel input, MMBtu/hr	Size, MW[a]	Fuel type	NO_x limit, ppmv[b]
1-100	1-10	Gas Oil	42 65
>100	10+	Gas Oil Gas/oil back-up	9[c] 9[c] 9[c]/18[c d]

[a]Based on gas turbine heat rate of 10,000 Btu/kW-hr.
[b]Dry basis, corrected to 15 percent oxygen.
[c]Based on use of selective catalytic reduction (SCR). Limits for operation without SCR, where permitted, should be the turbine manufacturer's lowest guaranteed NO_x limit.
[d]Based on the use of SCR and a fuel-bound nitrogen content of 600 ppm or less.

EXISTING TURBINES[4]

Operating cycle	Fuel	NO_x emission limit, ppmv, 15 percent O_2
Simple	Gas, no oil back-up	55
	Oil	75
	Gas, with oil back-up	55 (Gas fuel) 75 (Oil fuel)
Combined	Gas, no oil back-up	42
	Oil	65
	Gas, with oil back-up	42 (Gas fuel) 65 (Oil fuel)

Note: Applies to existing turbines rated at 25 MMBtu/hr or above (maximum heat input rate).

This chapter discusses the control techniques that are available to reduce NO_x emissions for stationary turbines, the use of duct burners, the use of alternate fuels to lower NO_x emissions, and the applicability of NO_x control techniques to offshore applications. Each control technique is structured into categories to discuss the process description, applicability, factors that affect performance, and achievable controlled NO_x emission levels. Where information for a technique is limited, one or more categories may be combined. Section 5.1 describes wet controls, including water and steam injection. Section 5.2 describes combustion controls, including lean and staged combustion. Selective catalytic reduction (SCR), a postcombustion technique, is described in Section 5.3, and the combination of SCR with other control techniques is described in

Section 5.4. Emissions from duct burners and their impact on total NO_x emissions are described in Section 5.5. Section 5.6 describes NO_x emission impacts when using alternate fuels. Two control techniques that show potential for future use, selective noncatalytic reduction (SNCR) and catalytic combustion, are described in Sections 5.7 and 5.8, respectively. Control technologies for offshore oil platforms are described in Section 5.9. Finally, references for Chapter 5 are found in Section 5.10.

5.1 WET CONTROLS

The injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_x formation. This control technique is available from all gas turbine manufacturers contacted for this study.[5-11]

The process description, applicability, factors affecting performance, emissions data and manufacturers' guarantees, impacts on other emissions, and gas turbine performance and maintenance impacts are discussed in this section.

5.1.1 Process Description

Injecting water into the flame area of a turbine combustor provides a heat sink that lowers the flame temperature and thereby reduces thermal NO_x formation. Injection rates for both water and steam are usually described by a water-to-fuel ratio (WFR) and are usually given on a weight basis (e.g., lb water to lb fuel).

A water injection system consists of a water treatment system, pump(s), water metering valves and instrumentation, turbine-mounted injection nozzles, and the necessary interconnecting piping. Water purity is essential to prevent or mitigate erosion and/or the formation of deposits in the hot section of the turbine; Table 5-4

TABLE 5-4. WATER QUALITY SPECIFICATIONS OF SELECTED GAS TURBINE MANUFACTURERS FOR WATER INJECTION SYSTEMS[11-18]

	Turbine Manufacturer							
Element	A	B	C	D	E	F	G	H
Total solids, ppm (dissolved and nondissolved)	5	5	1	a	0.1 gram/gallon	15	5	8
Total alkali metals, ppm	0.1	0.5 (HD) 0.1 (AD)[d]	0.1	--	0.5	0.15	<0.05	--
Calcium, ppm	5	--	--	--	--	--	<1.0	--
Sulfates, ppm	--	--	--	--	--	--	--	0.5
Silica, ppm	0.02	--	0.02	--	--	0.1	<0.02	0.1
Silicon, ppm	--	--	--	18.0	--	--	--	--
Sulfur, ppm	0.1	--	--	--	--	1.0	--	--
Chlorides, ppm	--	--	--	6.0	--	1.0	--	0.5
Iron and copper, ppm	--	--	--	0.1	--	--	--	--
Sodium and potassium, ppm	--	--	--	--	--	--	--	0.1
Particle size, microns	10	--	10	--	5	--	--	20
Total hardness, ppm	--	--	--	--	--	0.2	--	--
Oxygen[f]	--	--	--	--	--	--	--	--
Acidity, pH	7.0-8.5	6.5-7.5	7.0-8.5	7.5-8.0	--	6.5-7.5	6.5-7.0	6.0-8.0

[a]Determined by local regulations for particulates exhausted from combustion process.
[b]HD - heavy-duty turbine.
[c]Including vanadium and lead.
[d]AD - aeroderivative turbine.
[e]90 percent of 0.1 gram particles shall be less than 5 microns.

summarizes the water quality specifications for eight gas turbine manufacturers.

In a steam injection system, steam replaces water as the injected fluid. The injection system is similar to that for water injection, but the pump is replaced by a steam-producing boiler. This boiler is usually a heat recovery steam generator

(HRSG) that recovers the gas turbine exhaust heat and generates steam. The balance of the steam system is similar to the water injection system. The water treatment required for boiler feed water to the HRSG yields a steam quality that is suitable for injection into the turbine. The additional steam requirement for NO_x control, however, may require that additional capacity be added to the boiler feed water treatment system.

Another technique that is commercially available for oil-fired aeroderivative and industrial turbines uses a water-in-oil emulsion to reduce NO_x emissions. This technique introduces water into the combustion process by emulsifying water in the fuel oil prior to injection. This emulsion has a water content of 20 to 50 percent by volume and is finely dispersed and chemically stabilized in the oil phase. The principle of NO_x control is similar to conventional water injection, but the uniform dispersion of the water in the oil provides greater NO_x reduction than conventional water injection at similar WFR's.[19]

A water-in-oil emulsion injection system consists of mechanical emulsification equipment, chemical stabilizer injection equipment, water metering valves, chemical storage and metering valves, and instrumentation. In most cases the emulsifying system can be retrofitted to the existing fuel delivery system, which eliminates the requirement for a separate delivery system for water injection. At multiunit installations, one emulsion system can be used to supply emulsified fuel to several turbines. For dual fuel turbines, the emulsion can be injected through the oil fuel system to control NO_x emissions.[19]

Data provided by the vendor for this technique indicates that testing has been performed on oil-fired turbines operating in peaking duty. Long-term testing has not been completed at this point to quantify the long-term effects of the emulsifier on the operation and maintenance of the turbine.

5.1.2 Applicability of Wet Controls

Wet controls have been applied effectively to both aeroderivative and heavy-duty gas turbines and to all configurations except regenerative cycle applications.[20] It is expected that wet controls can be used with regenerative cycle turbines, but no such installations were identified. All manufacturers contacted have water injection control systems available for their gas turbine models; many also offer steam injection control systems. Where both systems are available, the decision of which control to use depends upon steam availability and economic factors specific to each site.

Wet controls can be added as a retrofit to most gas turbine installations. In the case of water injection, one limitation is the possible unavailability of injection nozzles for turbines operating in dual fuel applications. In this application, the injection nozzle as designed by the manufacturer may not physically accommodate a third injection port for water injection. This limitation also applies to steam injection. In addition, steam injection is not an available control option from some gas turbine manufacturers.

5.1.3 Factors Affecting the Performance of Wet Controls

The WFR is the most important factor affecting the performance of wet controls. Other factors affecting performance are the combustor geometry and injection nozzle(s) design and the fuel-bound nitrogen (FBN) content. These factors are discussed below.

The WFR has a significant impact on NO_x emissions. Tables 5-5 and 5-6 provide NO_x reduction and WFRs for natural gas and

TABLE 5-5. MANUFACTURER'S GUARANTEED NO_x REDUCTION EFFICIENCIES AND ESTIMATED WATER-TO-FUEL RATIOS FOR NATURAL GAS FUEL OPERATION[5-11,21-24]

	NO_x emission levels, ppmv at 15% O_2/NO_x percent reduction			Water-to-fuel ratio (lb water to lb fuel)	
Manufacturer/model	Uncontrolled	Water injection	Steam injection	Water injection	Steam injection
General Electric					
LM1600	133	42[a]/68	25/81	0.61	1.49
LM2500	174	42[a]/76	25/86	0.73	1.46
LM5000	185	42[a]/77	25/87	0.63	1.67
LM6000	220	42[a]/81	25/89	0.68	1.67
MS5001P	142	42/70	42/70	0.72	1.08
MS6001B	148	42/72	42/72	0.77	1.16
MS7001E	154	42/73	42/73	0.81	1.22
MS7001F	210	42/80	42/80	0.79	1.34
MS9001E	161	42/74	42/74	0.78	1.18
MS9001F	210	42/86	42/80	NA[b]	NA[b]
Asea Brown Boveri					
GT10	150	25/83	42/72	0.93	1.07
GT8	430	25/94	29/93	1.86	2.48
GT11N	390	25/94	25/94	1.76	2.47
GT35	300	42/86	60/80	1.00	1.20
Solar Turbines, Inc.					
T-1500 Saturn	99	42/58	NA[c]/NA[c]	0.33	NA[c]
T-4500 Centaur	130	42/68	NA[c]/NA[c]	0.61	NA[c]
Type H Centaur	105	42/60	NA[c]/NA[c]	0.70	NA[c]
Taurus	114	42/63	NA[c]/NA[c]	0.79	NA[c]
T-12000 Mars	178	42/76	NA[c]/NA[c]	0.91	NA[c]
T-14000 Mars	199	42/79	NA[c]/NA[c]	1.14	NA[c]
Allison/GM					
501-KB5	155	42/73	42/73	0.80	1.53
501-KC5	174	42/76	NA[c]/NA[c]	NA[b]	NA[c]
501-KH	155	42/73	25/84	NA[b]	NA[b]
570-K	101	42/58	NA[c]/NA[c]	NA[b]	NA[c]
571-K	101	42/58	NA[c]/NA[c]	0.80	NA[c]
Westinghouse					
251B11/12	220	42/81	25/89	1.0	1.8
501D5	190	25/87	25/87	1.6	1.6
Siemens					
V84.2	212	42/80	55/74	2.0	2.0
V94.2	212	55/74	55/74	1.6	1.6
V64.3	380	75/80	75/80	1.6	1.4
V84.3	380	75/80	75/80	1.6	1.4
V94.3	380	75/80	75/80	1.6	1.4

[a]A NO_x emissions level of 25 ppmv can be achieved, but turbine maintenance requirements increase over those required for 42 ppmv.

TABLE 5-6. MANUFACTURER'S GUARANTEED NO_x REDUCTION EFFICIENCIES AND ESTIMATED WATER-TO-FUEL RATIOS FOR DISTILLATE OIL FUEL OPERATION[5-11,21-24]

	NO_x emissions level, ppmv at 15% O_2/NO_x percent reduction			Water-to-fuel ratio (lb water to lb fuel)	
Manufacturer/model	Uncontrolled	Water injection	Steam injection	Water injection	Steam injection
General Electric					
LM1600	237	42/82	75/70	NA[a]	NA[a]
LM2500	345	42/88	75/78	0.99	NA[a]
LM5000	364	42/88	110/70	NA[a]	NA[a]
LM6000	417	42/90	110/74	NA[a]	NA[a]
MS5001P	211	65/69	65/69	0.79	1.06
MS6001B	267	65/76	65/76	0.73	1.20
MS7001E	228	65/72	65/72	0.67	1.19
MS7001F	353	65/82	65/77	0.72	1.35
MS9001E	241	65/73	65/72	0.65	1.16
MS9001F	353	65/82	65/76	NA[a]	NA[a]
Asea Brown Boveri					
GT10	200	42/79	42/79	0.75	1.25
GT8	680	42/94	60/91	1.62	2.15
GT11N	560	42/88	42/93	1.50	2.28
GT35	360	42/88	60/83	1.00	1.20
Solar Turbines, Inc.					
T-1500 Saturn	150	60/60	NA[b]/NA[b]	0.46	NA[b]
T-4500 Centaur	179	60/66	NA[b]/NA[b]	0.60	NA[b]
Type H Centaur	160	60/63	NA[b]/NA[b]	0.72	NA[b]
Taurus	168	60/64	NA[b]/NA[b]	0.96	NA[b]
T-12000 Mars	267	60/78	NA[b]/NA[b]	1.00	NA[b]
T-14000 Mars	NA[a]	60/NA[a]	NA[b]/NA[b]	NA[a]	NA[b]
Allison/GM					
501-KB5	231	56/76	NA[b]/NA[b]	NA[a]	NA[b]
501-KC5	NA[a]	NA[a]/NA[a]	NA[b]/NA[b]	NA[a]	NA[b]
501-KH	231	56/76[a]	50/78	NA[a]	NA[a]
570-K	182	65/64[a]	NA[b]/NA[b]	NA[a]	NA[b]
571-K	182	65/64[a]	NA[b]/NA[b]	NA[a]	NA[b]
Westinghouse					
251B11/12	355	65/82	42/88	1.0	1.8
501D5	250	42/83	42/83	1.0	1.6
Siemens					
V84.2	360	42/88	55/85	1.4	2.0
V94.2	360	42/88	55/85	1.4	1.6
V64.3	530	75/86	75/86	1.2	1.4
V84.3	530	75/86	75/86	1.2	1.4
V94.3	530	75/86	75/86	1.2	1.4

[a]Data not available.

distillate oil fuels, respectively, based on information provided by gas turbine manufacturers. For natural gas fuel, WFR's for water or steam injection range from 0.33 to 2.48 to achieve controlled NO_x emission levels ranging from 25 to 75 ppmv, corrected to 15 percent oxygen. For oil fuel, WFR's range from 0.46 to 2.28 to achieve controlled NO_x emission levels ranging from 42 to 110 ppmv, corrected to 15 percent oxygen. Nitrogen oxide reduction efficiency increases as the WFR

increases. As shown in Tables 5-5 and 5-6, reduction efficiencies of 70 to 90 percent are common. Note that, in general, the WFR's for steam are higher than for water injection because water acts as a better heat sink than steam due to the heat absorbed by vaporization; therefore, higher levels of steam than water must be injected for a given reduction level.

The combustor geometry and injection nozzle design and location also affect the performance of wet controls. For maximum NO_x reduction efficiency, the water must be atomized and injected in a spray pattern that provides a homogeneous mixture of water droplets and fuel in the combustor. Failure to achieve this mixing yields localized hot spots in the combustor that produce increased NO_x emissions.

The type of fuel affects the performance of wet controls. In general, lower controlled NO_x emission levels can be achieved with gaseous fuels than with oil fuels. The FBN content also affects the performance of wet controls. Those fuels with relatively high nitrogen content, such as coal-derived liquids, shale oil, and residual oils, result in significant fuel NO_x formation. Natural gas and most distillate oils are low-nitrogen fuels. Consequently, fuel NO_x formation is minimal when these fuels are burned.

Wet controls serve only to lower the flame temperature and therefore are an effective control only for thermal NO_x formation; water injection may in fact increase the rate of fuel NO_x formation, as shown in Figure 5-1.[25] The mechanisms responsible for this potential increase were not identified.

5.1.4 Achievable NO_x Emissions Levels Using Wet Controls

This section presents the achievable controlled NO_x emission levels for wet injection, as guaranteed by gas turbine manufacturers. Emission test data, obtained using EPA Test Method 20 or equivalent, are also presented.

Guaranteed NO_x emission levels as provided by gas turbine manufacturers for wet controls are shown in Figures 5-2 and

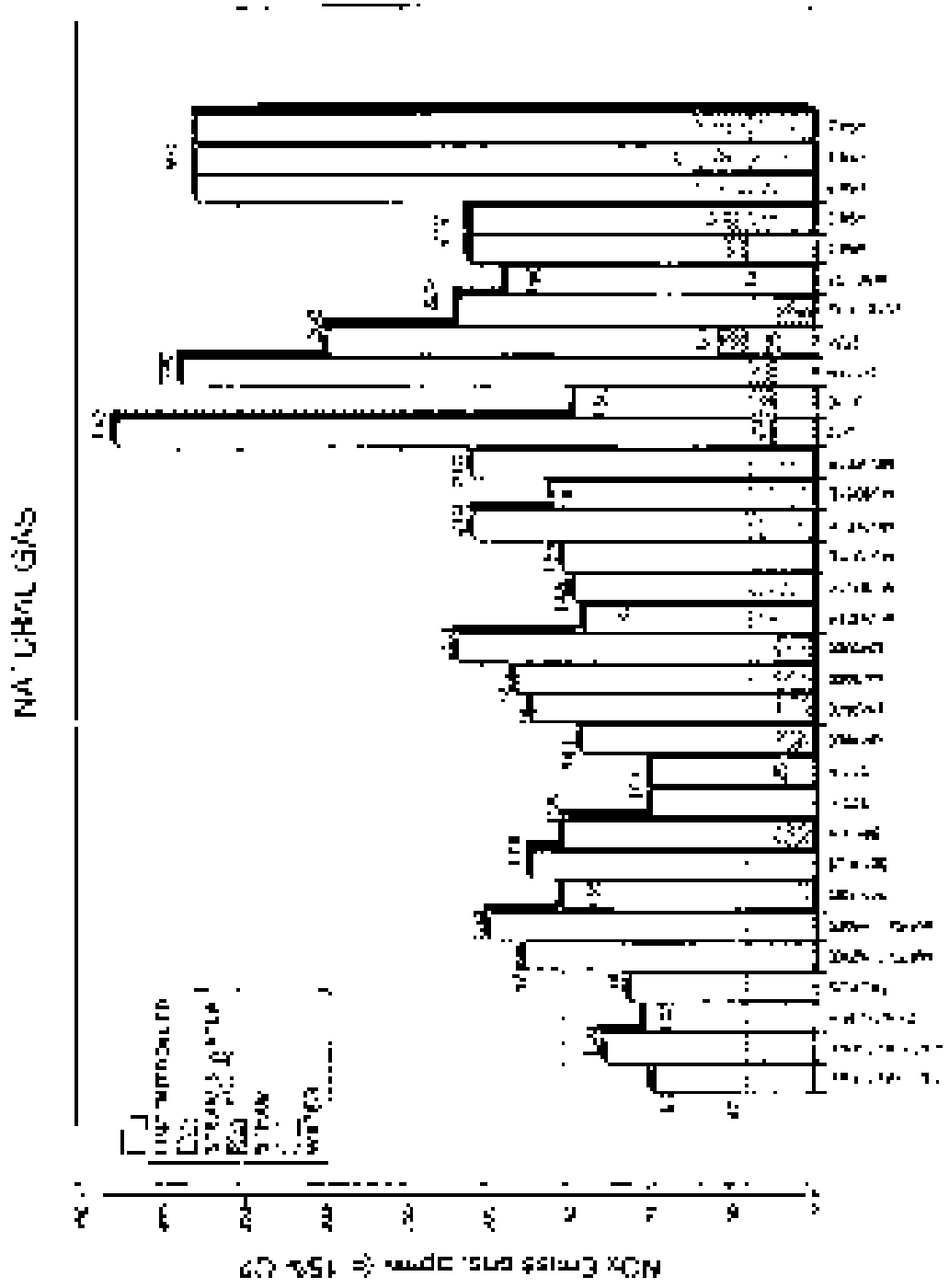


Figure 5-1. Percentage of fuel-bound nitrogen converted to NO_x versus the fuel-bound nitrogen content and the water-to-fuel ratio for controlled NO_x emissions and dry control.

Figure 5-2. Typical uncontrolled NO_x emissions and guaranteed controlled levels using wet injection. Natural gas fuel.

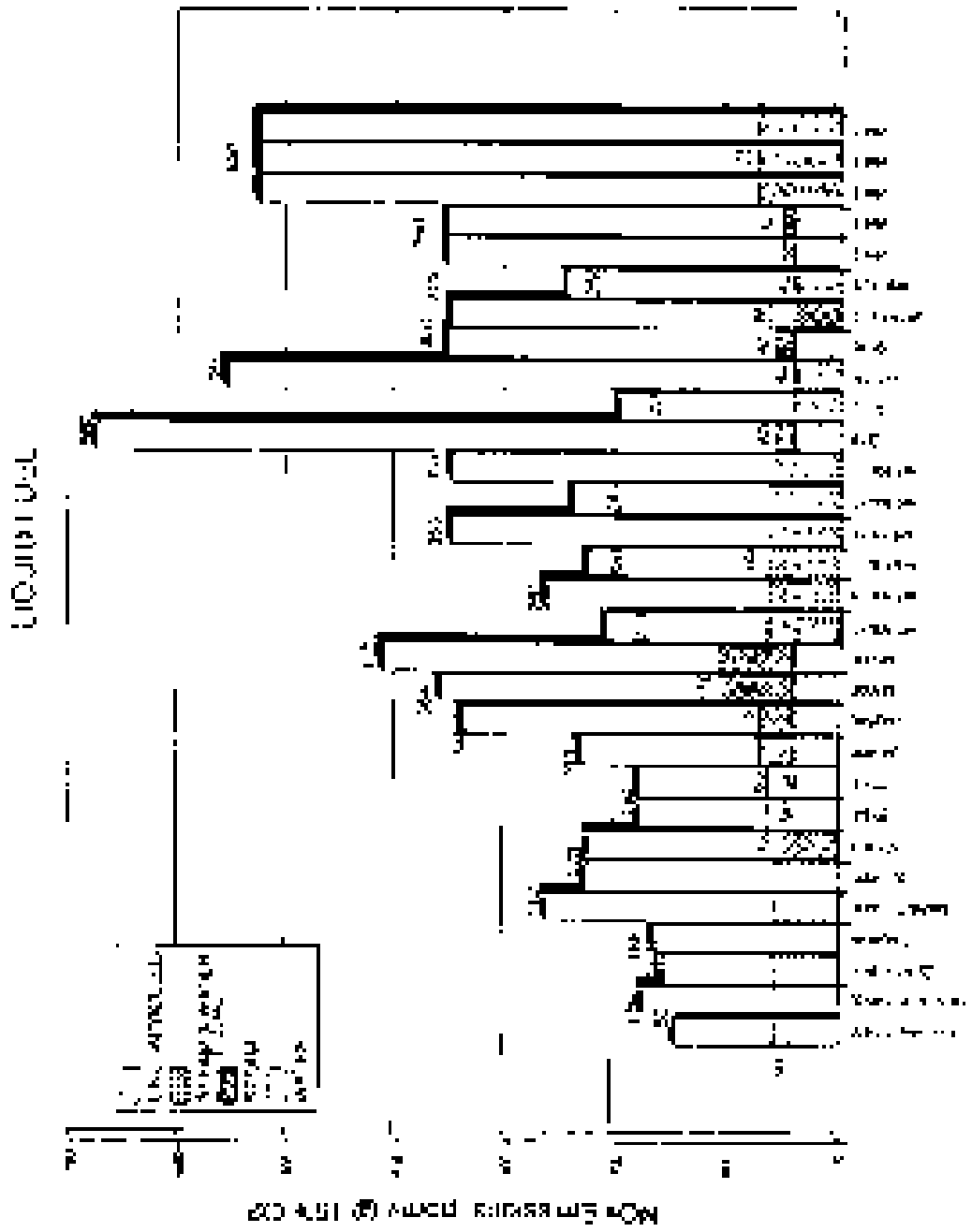


Figure 5-3. Uncontrolled NO_x emissions and gas turbine manufacturers' guaranteed controlled levels using wet injection. Distillate-oil fuel.[6-11,17,18,23]

5-3. These figures show manufacturers' guaranteed NO_x emission levels of 42 ppmv for most natural gas-fired turbines, and from 42 to

75 ppmv for most oil-fired turbines. The percent reduction in NO_x emissions varies for each turbine, ranging from 60 to 94 percent depending upon each model's uncontrolled emission level and whether water or steam is injected.

Emissions data for water and steam injection are presented to show the effects of wet injection on NO_x emissions. These data show:

1. That NO_x emissions decrease with increasing WFR's; and
2. That NO_x emissions are higher for oil fuel than for natural gas.

From the available data, reduction efficiencies of 70 to over 85 percent were achieved. The emission data and WFRs shown for specific turbine models may not reflect the emission levels of current production models, since manufacturers periodically update or otherwise modify their turbines, thereby altering specific emissions levels.

Each emission test in the following figures consists of one or more data points. Where data points were obtained under similar conditions, they are grouped together and presented as a single test. For these cases, each data point, along with the arithmetic average of all of the data points, is shown.

The nomenclature used to identify the tests consists of two letters followed by a number. The first letter of the two-letter designator specifies the turbine type. These types are as follows:

Letter	Turbine type
A	Aircraft-derivative turbine
H	Heavy-duty turbine
T	Small and low-efficiency turbine (less than 7.5 MW output, less than 30 percent simple-cycle efficiency)

The second letter identifies the facility. The number identifies the number of tests performed at the facility. Tests performed at the same facility on different turbines or at different times have the same two-letter designator but are followed by different test numbers. The short horizontal lines represent the average of the test data.

Also presented are the available data on the turbine, wet controls, uncontrolled NO_x emissions, percent NO_x reduction, and fuel type. All of the data shown are representative of the performance of wet controls when the turbine is operated at base load or peak load. These loads represent the worst-case conditions for NO_x emission reduction. Information on the WFR, turbine model, efficiency, control type, and fuel are included with the emission test data.

Figures 5-4, 5-5, and 5-6 present the emission test data

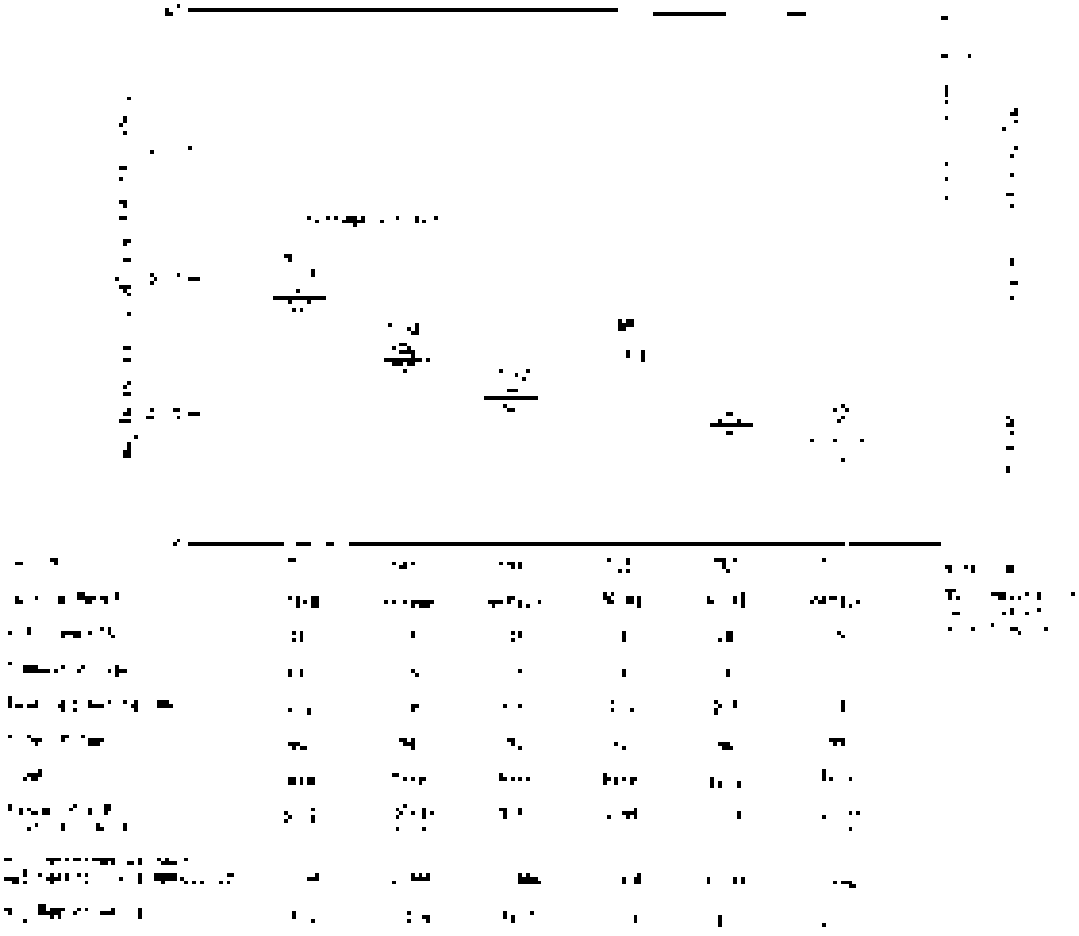


Figure 5-4. Nitrogen oxide emission test data for small, low-efficiency gas turbines with water injection firing natural gas.[27]

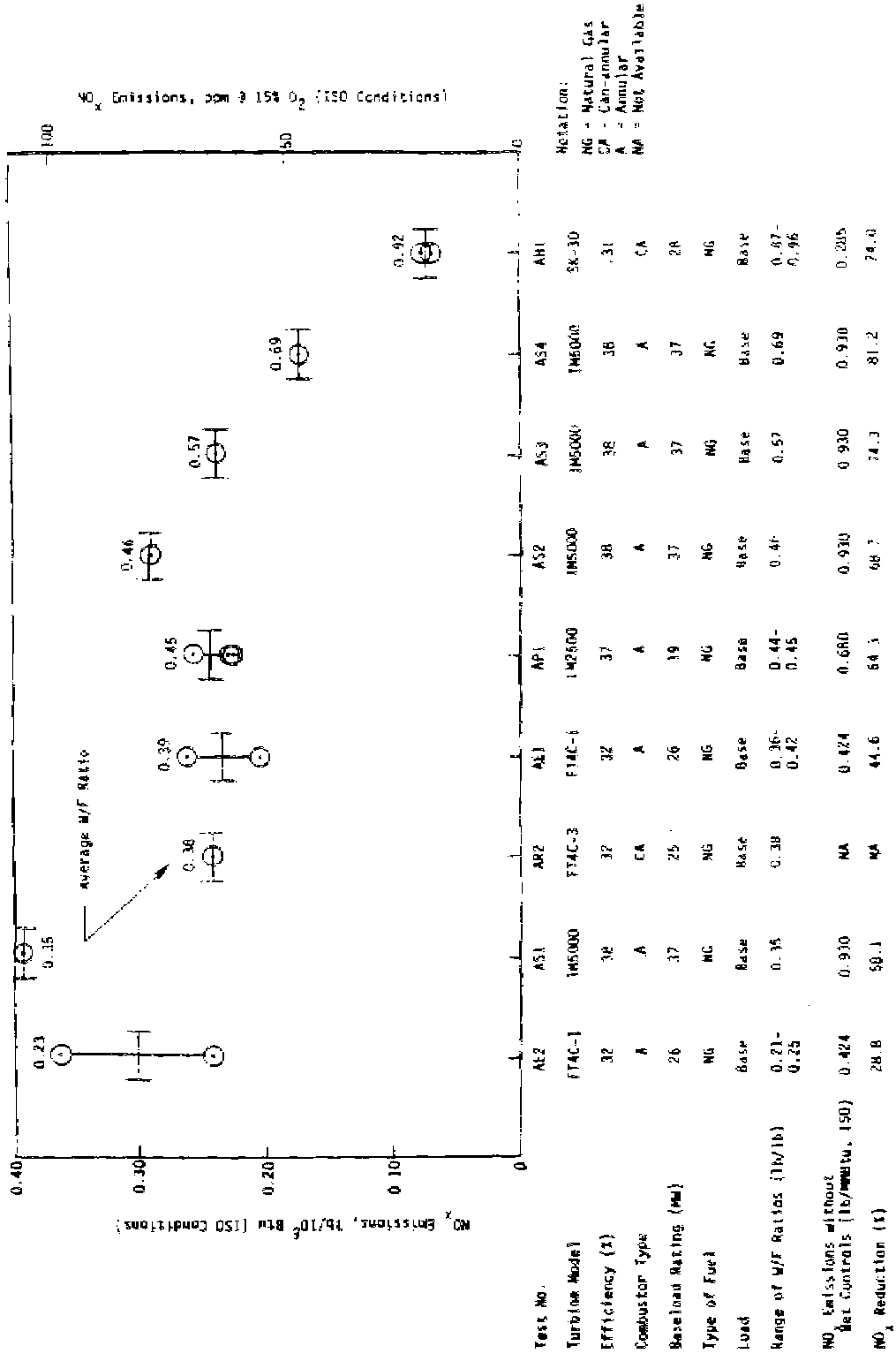


Figure 5-5. Nitrogen oxide emission test data for aircraft-derivative gas turbines with water injection firing natural gas.[27]

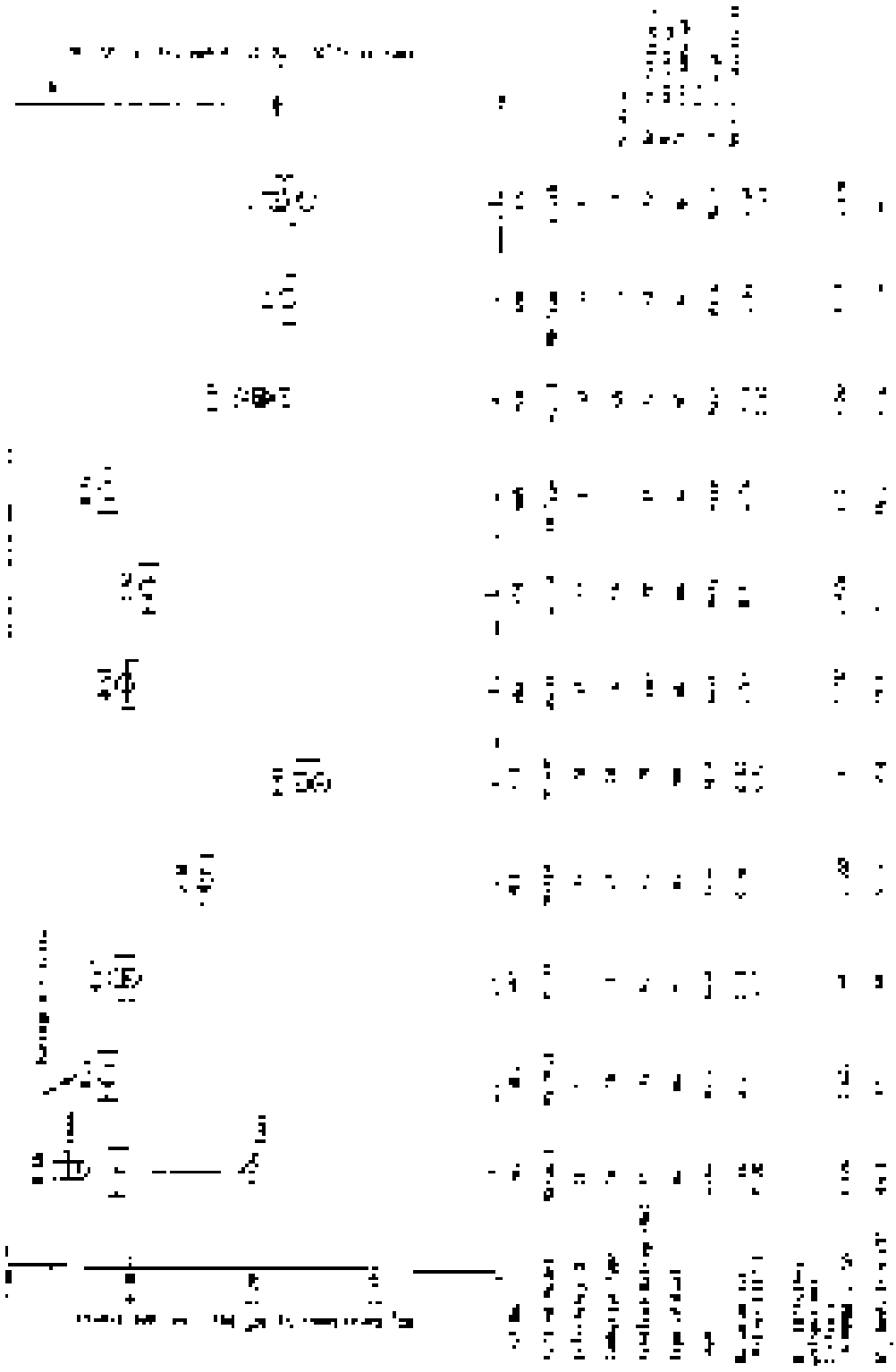
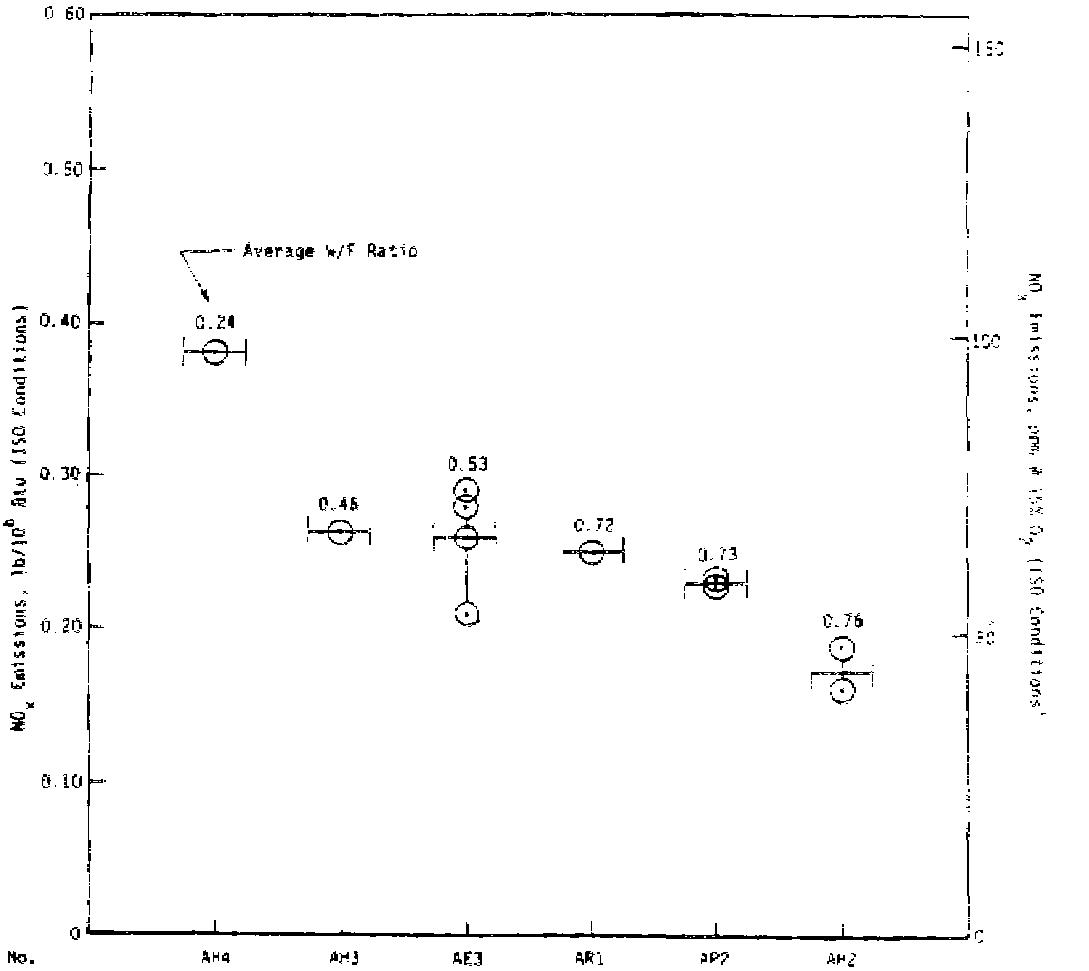


Figure 5-6. Nitrogen oxide emission test data for heavy-duty gas turbines with water injection firing natural gas.[27]

for water injection on turbines fired with natural gas. These turbines have NO_x emissions ranging from approximately 20 to 105 ppm with WFR's ranging from 0.16 to 1.32. Turbine sizes range from 2.8 to 97 MW. Based on these data, water injection is effective on all types of gas turbines and NO_x emission levels decrease as the WFR increases. However, some turbines require a higher WFR to meet a specific emission level. For example, the gas turbines at sites HH and HC (Figure 5-6) require much higher WFR's to achieve NO_x emission levels similar to the other gas turbine models shown. This particular gas turbine also has the highest uncontrolled NO_x emission levels. Conversely, the gas turbine at site AH, shown in Figure 5-5, has the lowest uncontrolled NO_x emission level and requires the least amount of water to achieve a given emission level. Uncontrolled NO_x emission levels vary for different turbine models depending upon design factors such as efficiency, firing temperature, and the extent of combustion controls incorporated in the combustor design (see Section 4.2.1.1). In general, aircraft-derivative and heavy-duty gas turbines require similar WFR's to achieve a specific emission level. Small, low-efficiency gas turbines require less water to achieve a specific emission level.

The NO_x emissions for turbines firing distillate oil are shown in Figures 5-7, 5-8, and 5-9. The data range from



Test No.	AH4	AH3	AE3	AR1	AP2	AH2
Turbine Model	SK-30	SK-30	FT4C-1	FT4C-3F	LM2500	SK-30
Efficiency (percent)	31	31	32	32	37	31
Combustor Type	CA	CA	CA	CA	A	CA
Base Load Rating (MW)	28	28	26	25	20	28
Type of Fuel	DO	DO	DO	DO	DO	DO
Load	Base	Base	Base	Base	Base	Base
Range of W/F Ratios (lb/lb)	0.24	0.46	0.51-0.55	0.72	0.73-0.73	0.68-0.84
NO_x Emissions without Wet Controls (lb/MMBtu, ISO)	0.559	0.559	0.787	0.840	1.37	0.559
NO_x Reduction (%)	32.0	52.8	66.8	70.5	83.4	58.9

Notation:
DO = distillate o
NG = natural gas
CA = can-annular
A = annular

Figure 5-7. Nitrogen oxide emission test data for aircraft-derivative gas turbines with water injection firing distillate oil.[27]

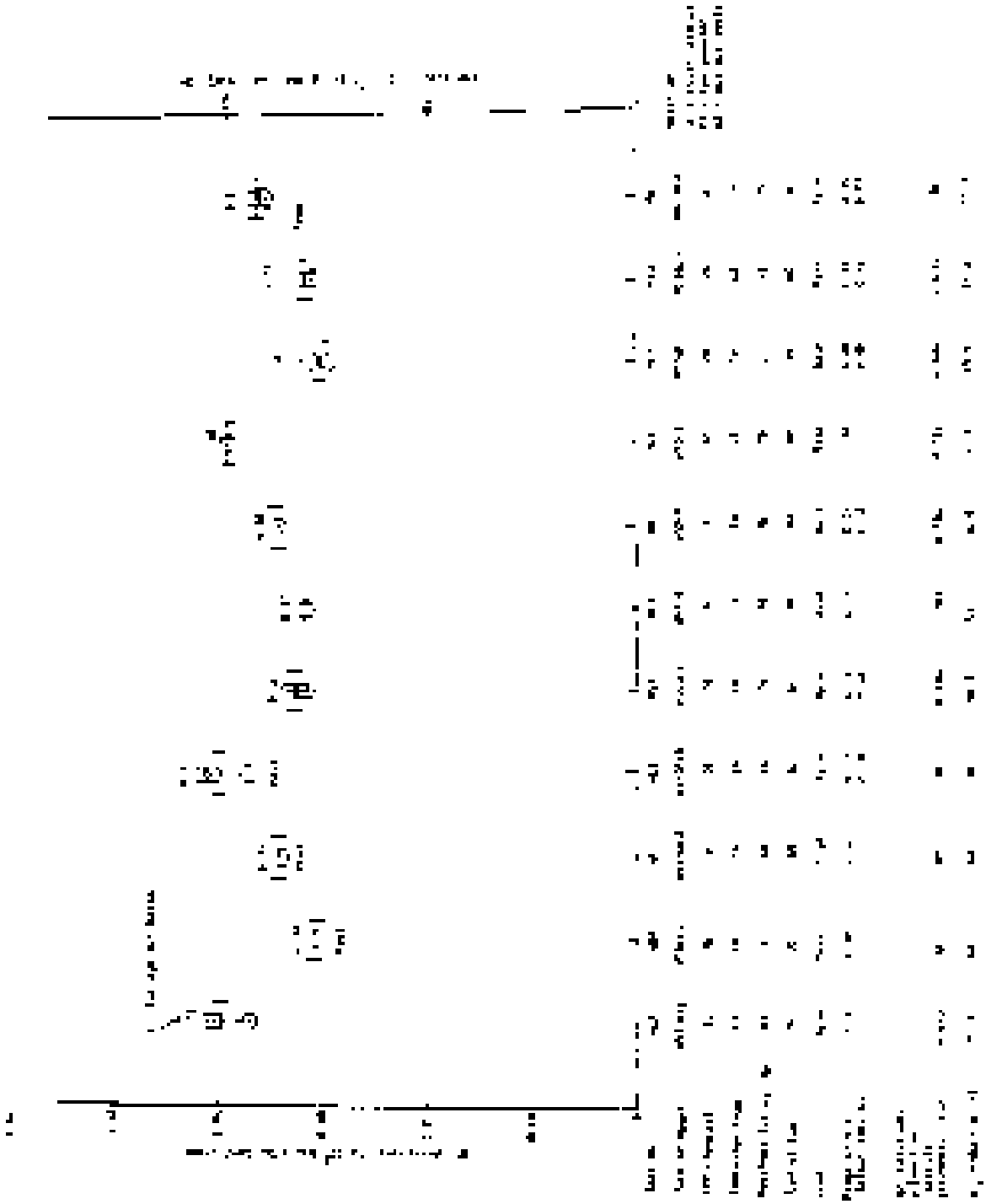


Figure 5-8. Nitrogen oxide emission test data for heavy-duty gas turbines with water injection and WFRs less than 0.5 and firing distillate oil.[27]

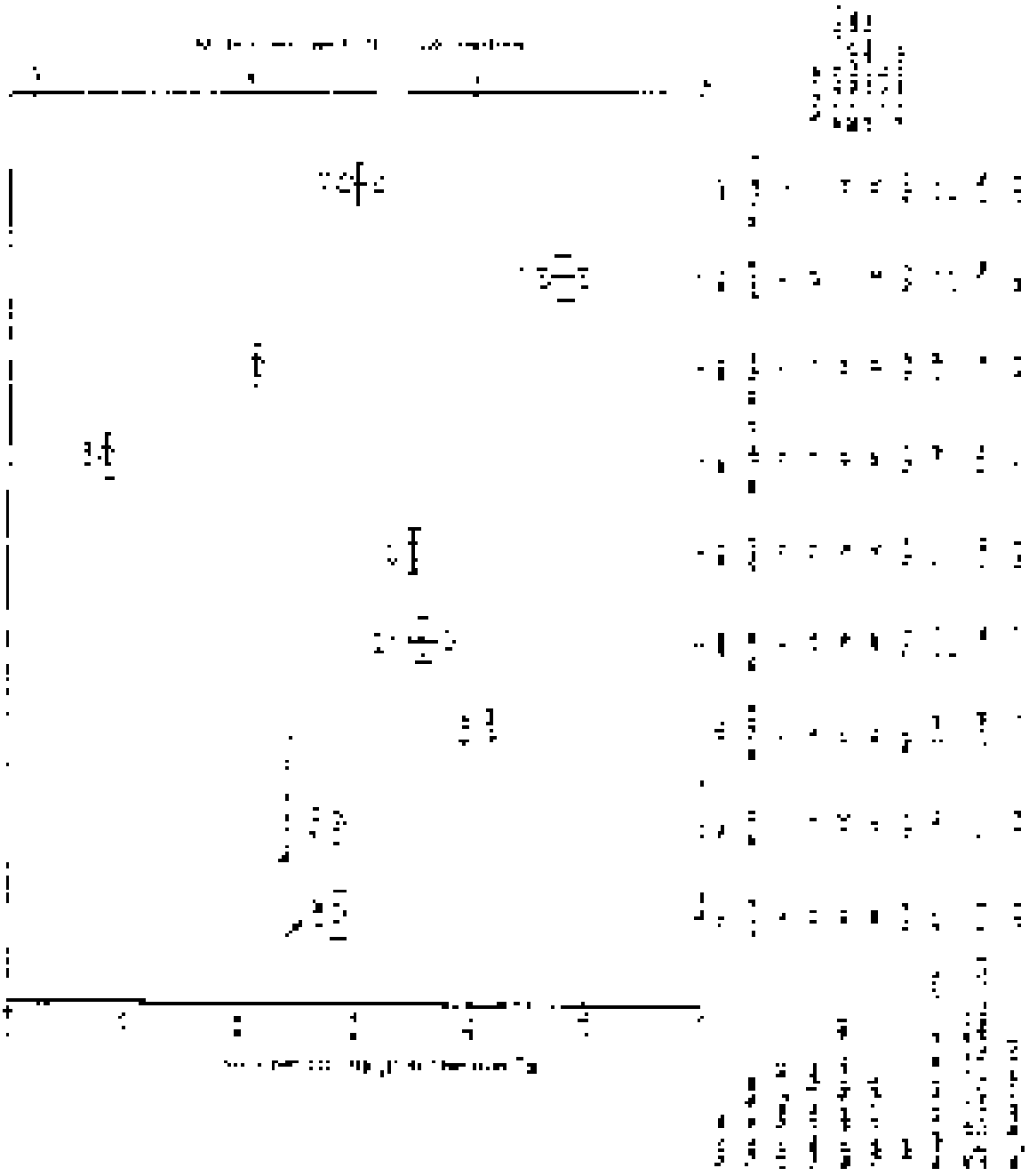


Figure 5-9. Nitrogen oxide emission test data for heavy-duty gas turbines with water injection and WFRs greater than 0.5 and firing distillate oil.[27]

approximately 30 to 135 ppm, with WFR's ranging from 0.24 to 1.31. The gas turbine sizes range from 19 to 95 MW. The data for distillate oil-fired turbines show the same general trends as the data for natural gas-fired turbines. Site HH (Figure 5-9)

again shows that higher WFR's are required due to the high uncontrolled NO_x emissions from this gas turbine. Also, by comparing the emission data for the distillate oil-fired turbines and natural gas-fired turbines, the data show that burning distillate oil requires higher WFR's than does burning natural gas for a given level of NO_x emissions. Higher WFR's are required because distillate oil produces higher uncontrolled NO_x levels than does natural gas (see Section 4.2.1.2).

The NO_x emission test data for steam injection are presented in Figures 5-10

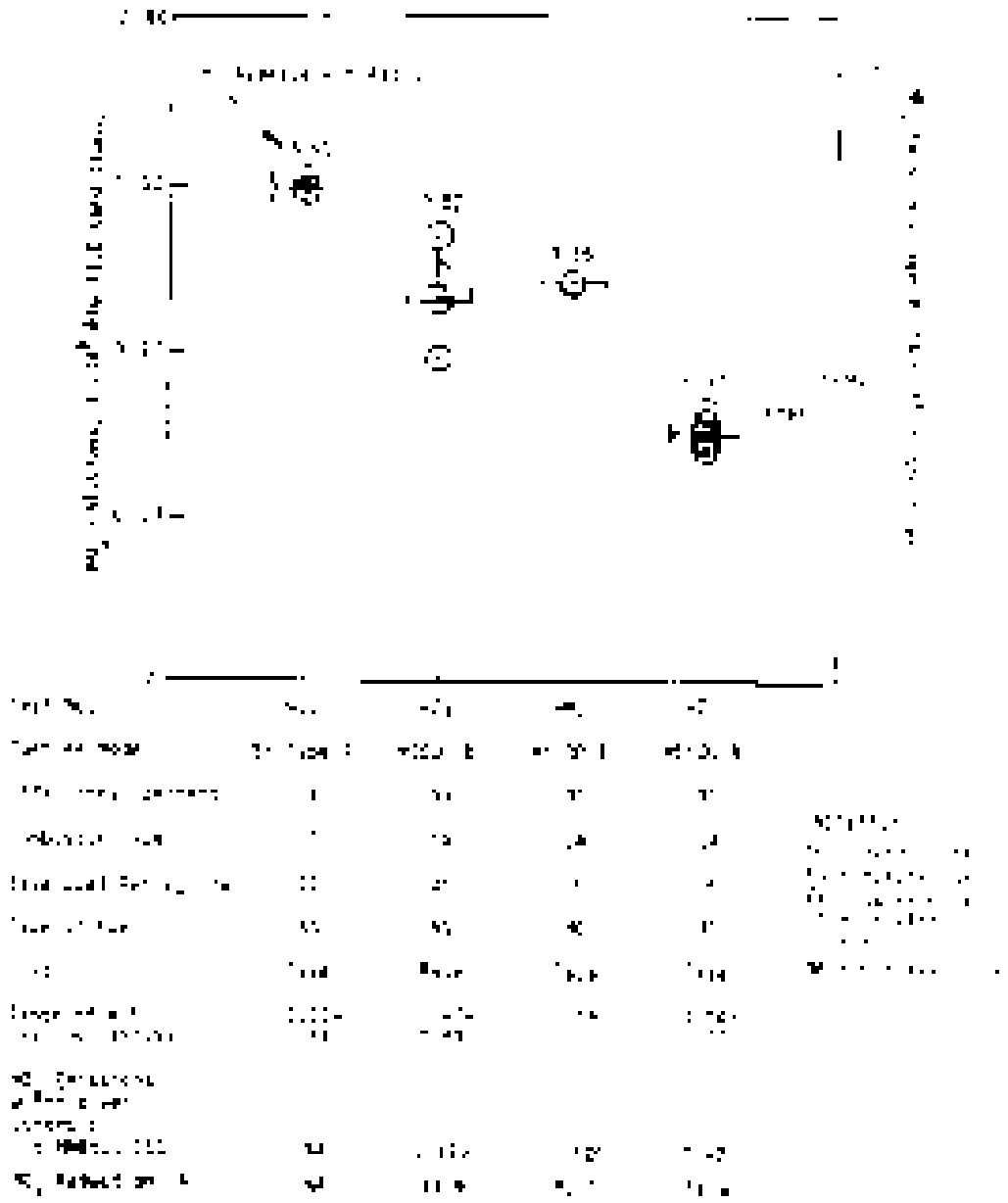


Figure 5-10. Nitrogen oxide emission test data for gas turbines with steam injection firing natural gas.[27]

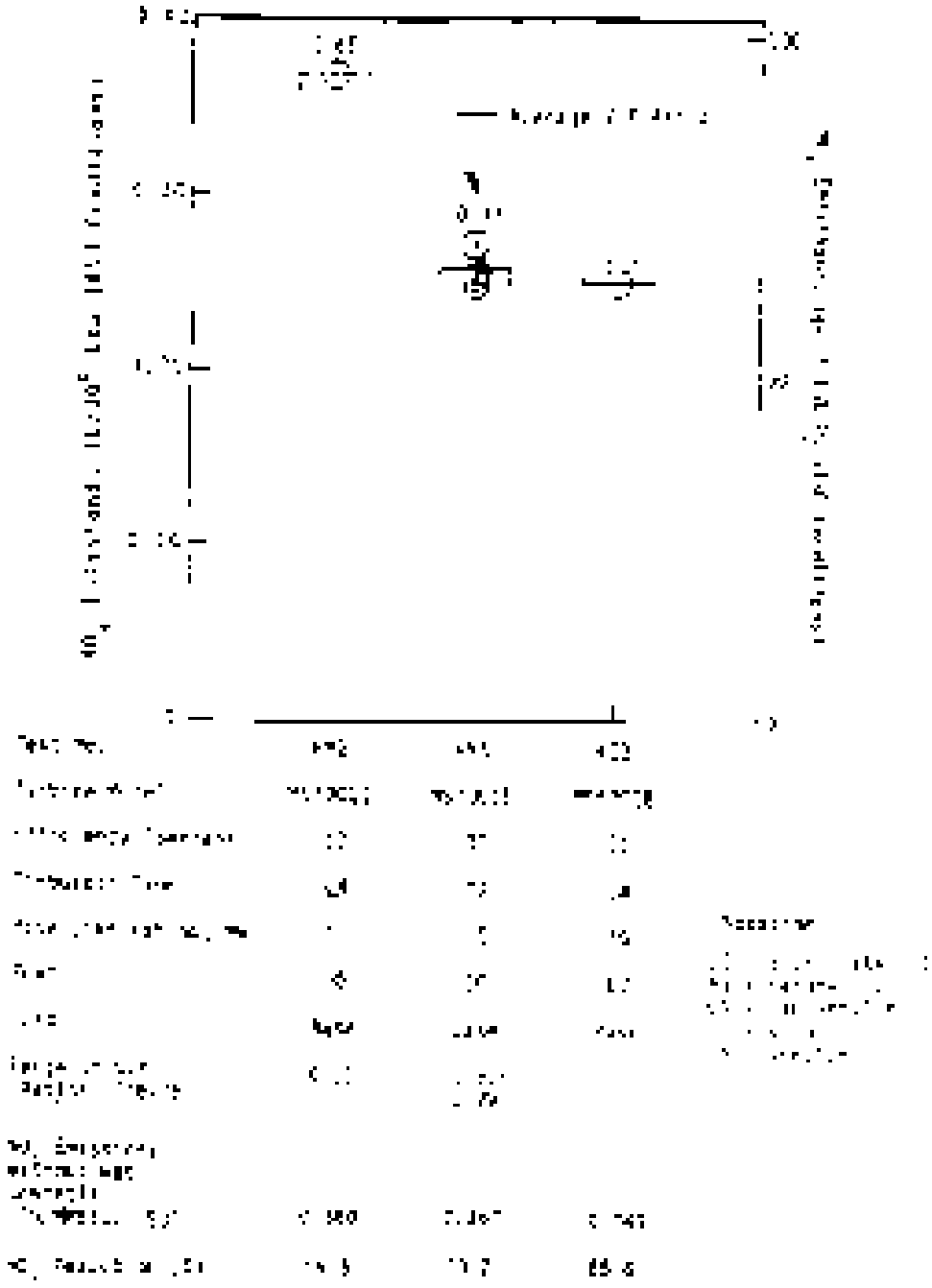


Figure 5-11. Nitrogen oxide emission test data for gas turbines with steam injection firing distillate oil.[27]

and 5-11 for natural gas-fired turbines and distillate oil-fired turbines, respectively. The turbines firing natural gas have NO_x emissions ranging from approximately 40 to 80 ppm, with WFR's ranging from 0.50 to 1.02. The gas turbine sizes range from 30 to 70 MW.

The NO_x emissions for turbines firing distillate oil range from approximately 65 to 95 ppm, with WFR's ranging from 0.65 to 1.01, and the gas turbine sizes tested were 36 and 70 MW. Fewer data points are available for steam injection than for water injection. However, the available data for both distillate oil-fired and natural gas-fired turbines show that NO_x emissions decrease as the steam-to-fuel ratio increases.

Reductions in NO_x emissions similar to water injection with oil-fired turbines have been achieved using water-in-oil emulsions. Results of emission tests for four turbines are shown in Table 5-7

TABLE 5-7. ACHIEVABLE GAS TURBINE NO_x EMISSION REDUCTIONS FOR OIL-FIRED TURBINES USING WATER-IN-OIL EMULSIONS[19]

				NO_x emissions, ppmv at 15 percent O_2		
Turbine manufacturer	Turbine model	Power output, MW	Water-to-fuel ratio	Uncontrolled	Controlled	Percent reduction
Turbo Power and Marine	A4	35	0.65	184	53	68
	A9	33	0.55	150	50	66
	A9	33	0.92	126	29	77
General Electric	MS5001	15	0.49	131	60	54

. The controlled NO_x emissions range from 29 to 60 ppmv, corresponding to NO_x reductions of 54 to 77 percent.[19] The controlled NO_x emission levels and percent reduction are consistent with those achieved using conventional water injection. Limited testing has shown that the emulsion achieves a given NO_x reduction level with a lower WFR than does a separate water injection arrangement. Test data for one oil-fired turbine showing a comparison of the WFR's for a water-in-oil emulsion versus a separate water injection system are shown in Figure 5-12

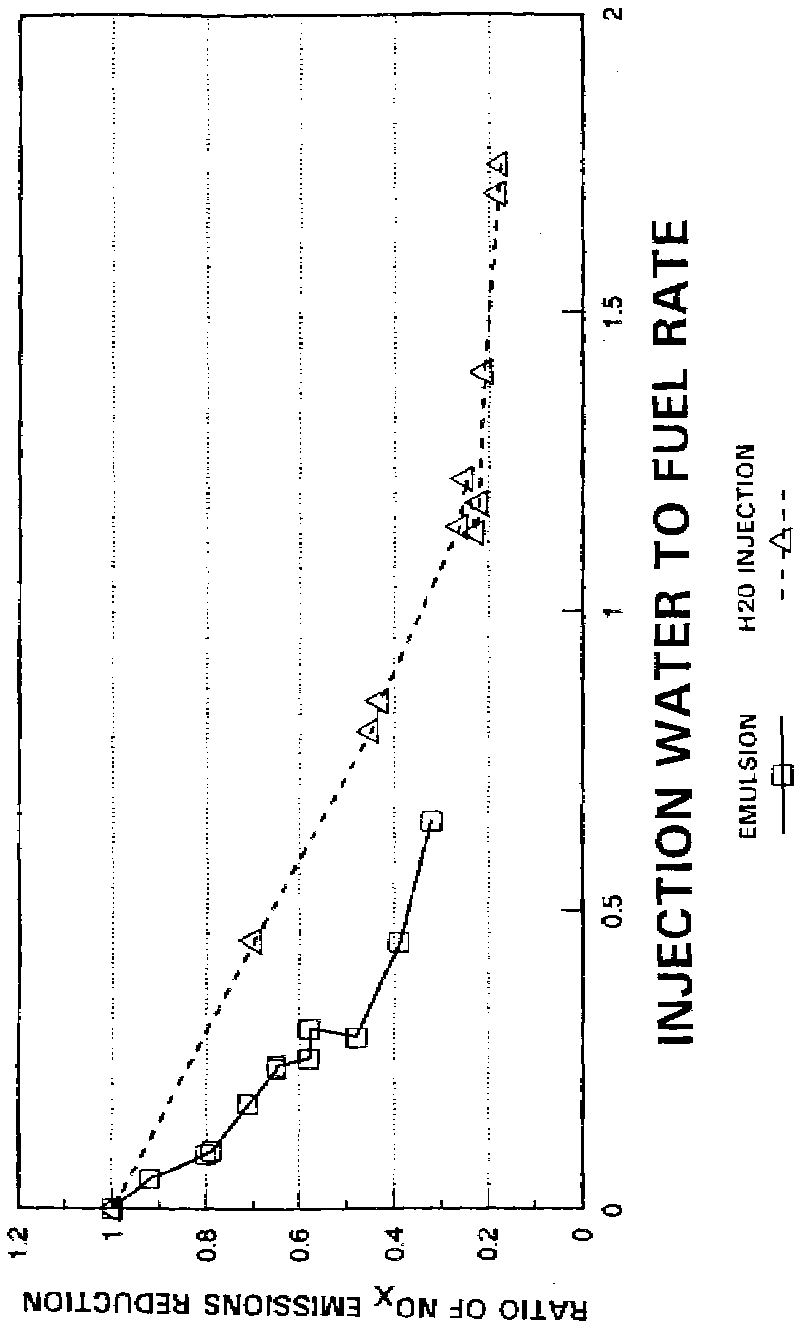


Figure 5-12. Comparison of the WFR requirement for water-in-oil emulsion versus separate water injection for an oil-fired turbine.[28]

. As shown here, NO_x reductions achieved by a water injection system at a WFR of 1.0 can be achieved by a water-in-oil emulsion at a WFR of 0.6.

On a mass basis, the reduction in NO_x emissions using water injection is shown in Table 5-8

TABLE 5-8. UNCONTROLLED NO_x EMISSIONS AND POTENTIAL NO_x REDUCTIONS FOR GAS TURBINES USING WATER INJECTION

Gas turbine model	Power output, MW[a]	NO_x emissions					
		Uncontrolled		Controlled		NO_x reduction	
		Gas fuel, lb/hr[b]	Oil fuel, lb/hr[b]	Gas fuel, lb/hr[b]	Oil fuel, lb/hr[b]	Gas fuel, tons/yr[c]	Oil fuel, tons/yr[c]
Saturn	1.1	6.4	9.9	2.8	4.1	14.3	23.3
Centaur	3.3	22.0	31.2	7.4	10.8	58.5	81.5
Centaur "H"	4.0	20.8	32.6	8.6	12.7	48.6	79.8
Taurus	4.5	24.7	37.6	9.4	13.9	61.1	94.9
Mars T-12000	8.8	69.4	107	17.0	24.9	210	329
Mars T-14000	10.0	85.4	NA[d]	18.7	NA[d]	267	NA[d]
501-KB5	4.0	31.6	48.5	8.9	12.2	90.9	145
570-K	4.9	22.7	41.0	9.8	15.2	51.8	103
571-K	5.9	24.2	44.0	10.4	16.3	55.1	111
LM1600	14.0	74.1	127	22.4	23.2	207	414
LM2500	22.7	146	301	36.4	37.9	438	1,050
LM5000	34.5	232	474	54.5	56.6	710	1,670
LM6000	43.0	310	609	61.3	63.5	996	2,180
MS5001P	26.8	181	274	55.5	87.4	503	747
MS6001B	39.0	250	459	73.2	116	704	1,370
MS7001E	84.7	544	822	154	243	1,560	2,320
MS7001F	161	1,290	2,190	267	417	4,090	7,090
MS9001E	125	810	1,320	219	369	2,370	3,820
MS9001F	229	1,850	3,150	382	600	5,850	10,200
GT8	47.4	899	1,440	54.1	92.3	3,380	5,410
GT10	22.6	143	196	24.6	42.6	472	614
GT11N	83.3	1,350	1,990	99.0	154	5,060	7,334
GT35	16.9	214	264	30.9	31.9	730	929
251B11/12	49.2	453	741	89.5	141	1,450	2,400
501D5	109	843	1,120	115	196	2,910	3,710
V84.2	105	858	1,570	176	190	2,730	5,520
V94.2	153	1,250	2,290	335	276	3,650	8,050
V64.3	61.5	859	1,290	176	188	2,740	4,390
V84.3	141	1,930	2,910	395	426	6,150	9,920
V94.3	204	2,790	4,170	571	611	8,890	14,200

[a]Power output at ISO conditions, without wet injection, with natural gas fuel.
[b]Based on ppmv levels shown in Tables 5-5 and 5-6. See Appendix A for conversion from ppmv to lb/hr.
[c]Based on 8,000 hours operation per year.
[d]Data not available.

; Table 5-9 shows uncontrolled NO$_x$ emissions and potential NO$_x$ reduction.

TABLE 5-9. UNCONTROLLED NO$_x$ EMISSIONS AND POTENTIAL NO$_x$ REDUCTIONS FOR GAS TURBINES USING STEAM INJECTION

Gas turbine model	Power output, MW[a]	NO$_x$ emissions					
		Uncontrolled		Controlled		NO$_x$ reduction	
		Gas fuel, lb/hr[b]	Oil fuel, lb/hr[b]	Gas fuel, lb/hr[b]	Oil fuel, lb/hr[b]	Gas fuel, tons/yr[c d]	Oil fuel, tons/yr[c d]
Saturn	1.1	6.4	9.9	6.4	9.9	0	0
Centaur	3.3	22.0	31.2	22.0	31.2	0	0
Centaur "H"	4.0	20.8	32.6	20.8	32.6	0	0
Taurus	4.5	24.7	37.6	24.7	37.6	0	0
Mars T-12000	8.8	69.4	107	69.4	107	0	0
501-KB5	4.0	31.6	48.5	8.6	48.5	194	0
570-K	4.9	22.7	41.0	22.7	41.0	0	0
571-K	5.9	24.2	44.0	24.2	44.0	0	0
LM1600	14.0	74.1	127	13.0	40.5	245	345
LM2500	22.7	146	301	21.2	66.0	499	938
LM5000	34.5	232	474	31.7	145	802	1,320
LM6000	43.0	310	609	35.6	162	1,100	1,790
MS5001P	26.8	181	274	54.1	85.3	508	755
MS6001B	39.0	250	459	71.4	113	711	1,380
MS7001E	84.7	544	822	150	237	1,580	2,340
MS7001F	161	1,290	2,190	260	407	4,110	7,130
MS9001E	125	810	1,320	214	360	2,390	3,850
MS9001F	229	1,850	3,150	373	585	5,890	10,200
GT8	47.4	899	1,440	61.2	129	3,350	5,260
GT10	22.6	143	196	40.4	41.6	410	618
GT11N	83.3	1,350	1,990	147	151	4,830	7,350
GT35	16.9	214	264	43.1	44.4	681	878
251B11/12	49.2	453	741	52.0	88.6	1,600	2,610
501D5	109	843	1,120	112	191	2,920	3,730
V84.2	105	858	1,570	225	242	2,530	5,310
V94.2	153	1,250	3,290	327	353	3,690	7,740
V64.3	61.5	859	1,290	171	184	2,750	4,410
V84.3	141	1,930	2,910	386	415	6,190	9,960
V94.3	204	2,790	4,170	557	596	8,940	14,300

[a]Power output at ISO conditions, without wet injection, with natural gas fuel.
[b]Based on ppmv levels shown in Tables 5-5 and 5-6. See Appendix A for conversion from ppmv to lb/hr.

As an example, a 21.8 MW turbine burning natural gas fuel can reduce NO_x emissions by 452 tons/yr (8,000 hours operation) using water injection and 511 tons/yr using steam injection. This same turbine burning oil fuel will reduce annual NO_x emissions by 1,040 tons using water injection and by 925 tons using steam injection.

5.1.5 Impacts of Wet Controls on CO and HC Emissions

While carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines, water injection may increase these emissions. Figure 5-13

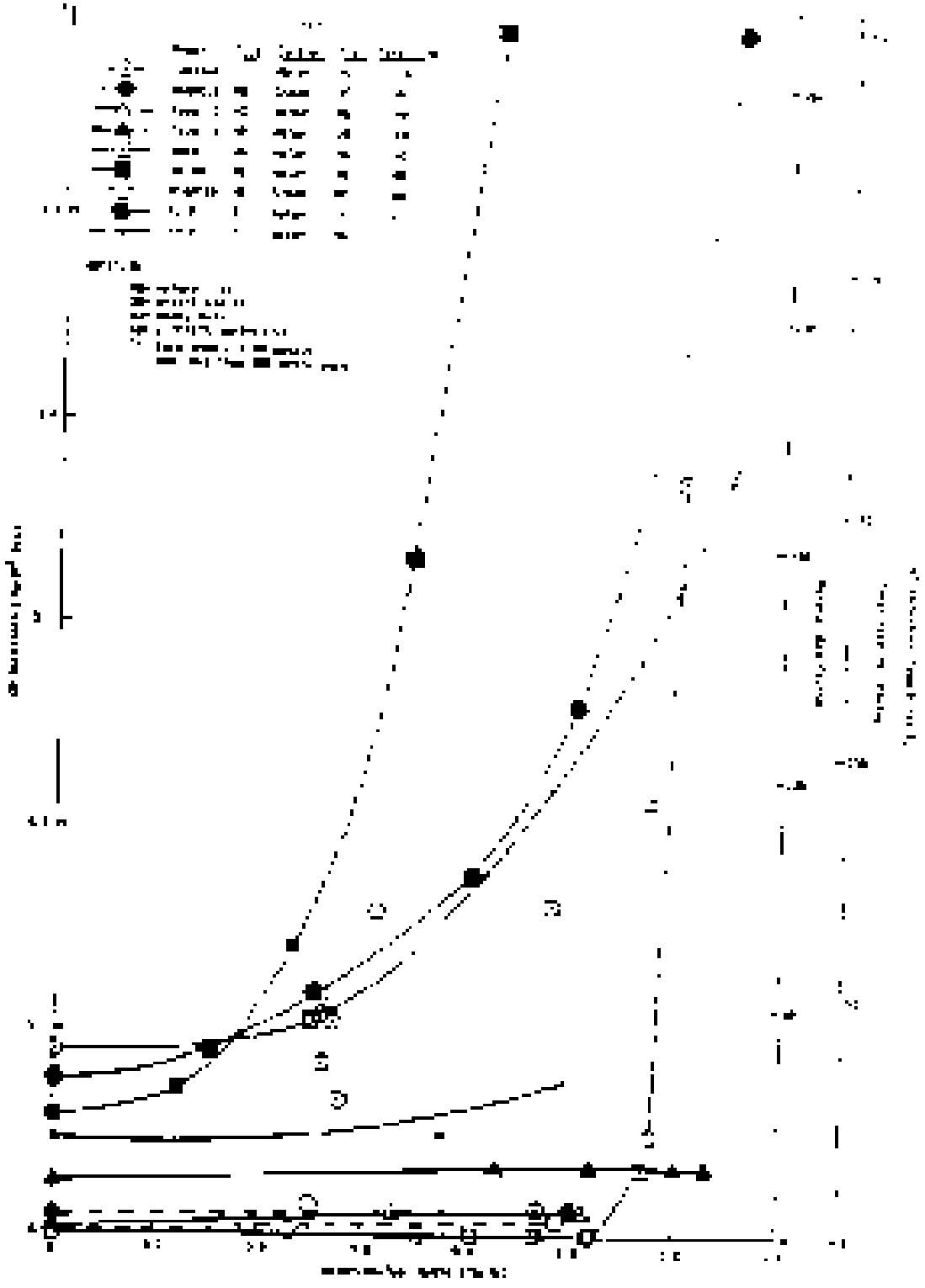


Figure 5-13. Effect of wet injection on CO emissions.[29]

shows the impact of water injection on CO emissions for several production gas turbines. In many turbines, CO emissions increase as the WFR increases, especially at WFR's above 0.8. Steam injection also increases CO emissions at relatively high WFR's, but the impact is less than that of water injection.[29,30]

Water and steam injection also increase HC emissions, but to a lesser extent than CO emissions.[29,30] The effect of water injection on HC emissions for one turbine is shown in

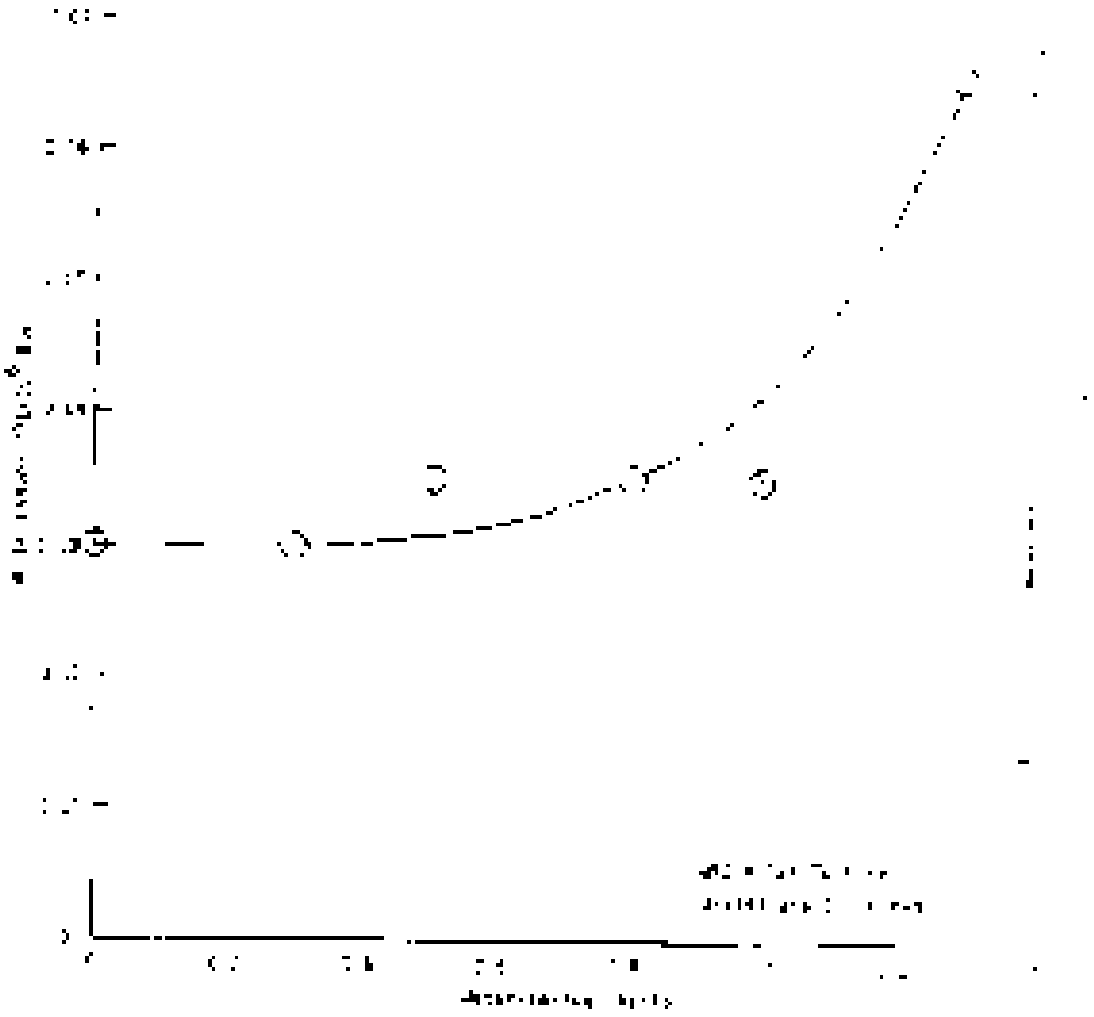


Figure 5-14. Effect of water injection on HC emissions for one turbine model.[29]

Figure 5-14. Like CO emissions, hydrocarbon emissions increase at WFR's above 0.8.

For applications where the water or steam injection rates required for NO_x emission reductions result in excess CO and/or HC emissions, it may be possible to select an alternative turbine and/or fuel with a relatively flat CO curve, as indicated in Figure 5-13. Another alternative is an oxidation catalyst to reduce these emissions. This oxidation catalyst is an add-on control device that is placed in the turbine exhaust duct or HRSG and serves to oxidize CO and HC to H_2O and CO_2. The catalyst material is usually a precious metal (platinum, palladium, or rhodium), and oxidation efficiencies of 90 percent or higher can be achieved. The oxidation process takes place spontaneously, without the requirement for introducing reactants (such as ammonia) into the flue gas stream.[31]

5.1.6 Impacts of Wet Controls on Gas Turbine Performance

Wet controls affect gas turbine performance in two ways: power output increases and efficiency decreases. The energy from the added mass flow and heat capacity of the injected water or steam can be recovered in the turbine, which results in an increase in power output. For water injection, the fuel energy required to vaporize the water in the turbine combustor, however, results in a net penalty to the overall efficiency of the turbine. For steam injection, there is an energy penalty associated with generating the steam, which results in a net penalty to the overall cycle efficiency. Where the steam source is exhaust heat, which would otherwise be exhausted to the atmosphere, the heat recovery results in a net gain in gas turbine efficiency.[32] The actual efficiency reduction associated with wet controls is specific to each turbine and the actual WFR required to meet a specific NO_x reduction. The overall efficiency penalty increases with increasing WFR and is usually higher for water injection than for steam injection due to the heat of vaporization associated with water. The impacts on output and efficiency for one manufacturer's gas turbines are shown in Table 5-10.

TABLE 5-10. REPRESENTATIVE WATER/STEAM INJECTION IMPACTS ON GAS TURBINE PERFORMANCE FOR ONE MANUFACTURER'S HEAVY-DUTY TURBINES[33]

NO_x level, ppmv	Water/fuel ratio	Percent overall efficiency change	Percent output change[a]	Remarks
75 NSPS	0.5	-1.8	+3	Oil-fired, simple cycle, water injection
42	1.0	<-3	+5	Natural gas, simple cycle, water injection
42	1.2	-2	+5	Natural gas, combined cycle, steam injection
25	1.2	-4	+6	Natural gas, water injection, multinozzle combustor
25	1.3	-3	+5.5	Natural gas, steam injection, combined cycle (Frame 6 turbine model)

[a]Compared with no injection.

5.1.7 Impacts of Wet Controls on Gas Turbine Maintenance

Water injection increases dynamic pressure oscillation activity in the turbine combustor.[33] This activity can, in some turbine models, increase erosion and wear in the hot section of the turbine, thereby increasing maintenance requirements. As a result, the turbine must be removed from service more frequently for inspection and repairs to the hot section components. A summary of the maintenance impacts as provided by manufacturers is shown in Table 5-11.

TABLE 5-11. IMPACTS OF WET CONTROLS ON GAS TURBINE MAINTENANCE USING NATURAL GAS FUEL[5-11,17,24]

Manufacturer/Model	NO_x emissions, ppmv @ 15% O_2			Inspection interval, hours		
	Standard combustor	Water injection	Steam injection	Standard	Water injection	Steam injection
General Electric						
LM1600	133	42/25	25	25,000	16,000[a]	25,000
LM2500	174	42/25	25	25,000	16,000[a]	25,000
LM5000	185	42/25	25	25,000	16,000[a]	25,000
LM6000	220	42/25	25	25,000	16,000[a]	25,000
MS5001P	142	42	42	12,000	6,000	6,000
MS6001B	148	42	42	12,000	6,000	8,000
MS7001E	154	42	42	8,000	6,500	8,000
MS7001F	179	42	42	8,000	8,000	8,000
MS9001E	176	42	42	8,000	6,500	8,000
MS9001F	176	42	42	8,000	8,000	8,000
Asea Brown Boveri						
GT10	150	25	42	80,000[b]	80,000[b]	80,000[b]
GT8	430	25	29	24,000	24,000	24,000
GT11N	400	25	25	24,000	24,000	24,000
GT35	300	42	60	80,000[b]	80,000[b]	80,000[b]
Siemens Power Corp.						
V84.2	212	42	55	25,000	25,000	25,000
V94.2	212	55	55	25,000	25,000	25,000
V64.3	380	75	75	25,000	25,000	25,000
V84.3	380	75	75	25,000	25,000	25,000
V94.3	380	75	75	25,000	25,000	25,000
Solar Turbines, Inc.						
T-1500 Saturn	99	42	NA[c]	NA[d]	NA[d]	NA[c]
T-4500 Centaur	150	42	NA[c]	NA[d]	NA[d]	NA[c]
Type H Centaur	105	42	NA[c]	NA[d]	NA[d]	NA[c]
Taurus	114	42	NA[c]	NA[d]	NA[d]	NA[c]
T-12000 Mars	178	42	NA[c]	NA[d]	NA[d]	NA[c]
T-14000 Mars	199	42	NA[c]	NA[d]	NA[d]	NA[c]
Allison/General Motors						
501-KB5	155	42	NA[c]	25,000	17,000	NA[d]
501-KC5	174	42	NA[c]	30,000	22,000	NA[d]
501-KH	155	42	25	25,000	17,000	20,000
570-K	101	42	NA[c]	20,000	12,000	NA[d]
571-K	101	42	NA[c]	20,000	12,000	NA
Westinghouse						
251B11/12	220	42	25	8,000	8,000	8,000
501D5	190	25	25	8,000	8,000	8,000

[a]Applies only to 25 ppmv level. No impact for 42 ppmv.
[b]This interval applies to time between overhaul (TBO).
[c]Steam injection is not available for this model.
[d]Data not available.

As this table shows, the maintenance impact, if any, varies from manufacturer to manufacturer and model to model. Some manufacturers stated that there is no impact on maintenance intervals associated with water or steam injection for their turbine models. Data were provided only for operation with natural gas.

5.2 COMBUSTION CONTROLS

The formation of both thermal NO_x and fuel NO_x depends upon combustion conditions, so modification of these conditions affects NO_x formation. The following combustion modifications are used to control NO_x emission levels:

1. Lean combustion;
2. Reduced combustor residence time;
3. Lean premixed combustion; and
4. Two-stage rich/lean combustion.

These combustion modifications can be applied singly or in combination to control NO_x emissions.

The mechanisms by which each of these techniques reduce NO_x formation, their applicability to new gas turbines, and the design or operating factors that influence NO_x reduction performance are discussed below by control technique.

5.2.1 Lean Combustion and Reduced Combustor Residence Time

5.2.1.1 Process Description. Gas turbine combustors were originally designed to operate with a primary zone equivalence ratio of approximately 1.0. (An equivalence ratio of 1.0 indicates a stoichiometric ratio of fuel and air. Equivalence ratios below 1.0 indicate fuel-lean conditions, and ratios above 1.0 indicate fuel-rich conditions.) With lean combustion, the additional excess air cools the flame, which reduces the peak flame temperature and reduces the rate of thermal NO_x formation.[34]

In all gas turbine combustor designs, the high-temperature combustion gases are cooled with dilution air to an acceptable temperature prior to entering the turbine. This dilution air rapidly cools the hot gases to temperatures below those required for thermal NO_x formation. With reduced residence time combustors, dilution air is added sooner than with standard combustors. Because the combustion gases are at a high temperature for a shorter time, the amount of thermal NO_x formed decreases.[34]

Shortening the residence time of the combustion products at high temperatures may result in increased CO and HC emissions if

no other changes are made in the combustor. In order to avoid increases in CO and HC emissions, combustors with reduced residence time also incorporate design changes in the air distribution ports to promote turbulence, which improves fuel/air mixing and reduces the time required for the combustion process to be completed. These designs may also incorporate fuel/air premixing chambers. Therefore, the differences between reduced residence time combustors and standard combustors are the placement of the air ports, the design of the circulation flow patterns in the combustor, and a shorter combustor length.[34]

5.2.1.2 Applicability. Lean primary zone combustion and reduced residence time combustion have been applied to annular, can-annular, and silo combustor designs.[35-37] Almost all gas turbines presently being manufactured incorporate lean combustion and/or reduced residence time to some extent in their combustor designs, incorporating these features into production models since 1975.[38,39] However, the varying uncontrolled NO_x emission levels of gas turbines shown in Figures 5-2 and 5-3 indicate that these controls are not incorporated to the same degree in every gas turbine and may be limited in some turbines by the quantity of dilution air available for lean combustion.

Lean primary zone and reduced residence time are most applicable to low-nitrogen fuels, such as natural gas and distillate oil fuels. These modifications are not effective in reducing fuel NO_x.[40]

5.2.1.3 Factors Affecting Performance. For a given combustor, the performance of lean combustion is directly affected by the primary zone equivalence ratio. As shown in Figure 4-2, the further the equivalence ratio is reduced below 1.0, the greater the reduction in NO_x emissions. However, if the equivalence ratio is reduced too far, CO emissions increase and flame stability problems occur.[41] This emissions tradeoff effectively limits the amount of NO_x reduction that can be achieved by lean combustion alone.

For combustors with reduced residence time, the amount of NO_x emission reduction achieved is directly related to the decrease in residence time in the high-temperature flame zone.

5.2.1.4 Achievable NO_x Emission Levels Using Lean Combustion and Reduced Residence Time Combustors. Lean combustion reduces NO_x emissions, and when used in combination with reduced residence time, NO_x emissions are further reduced. Figure 5-1

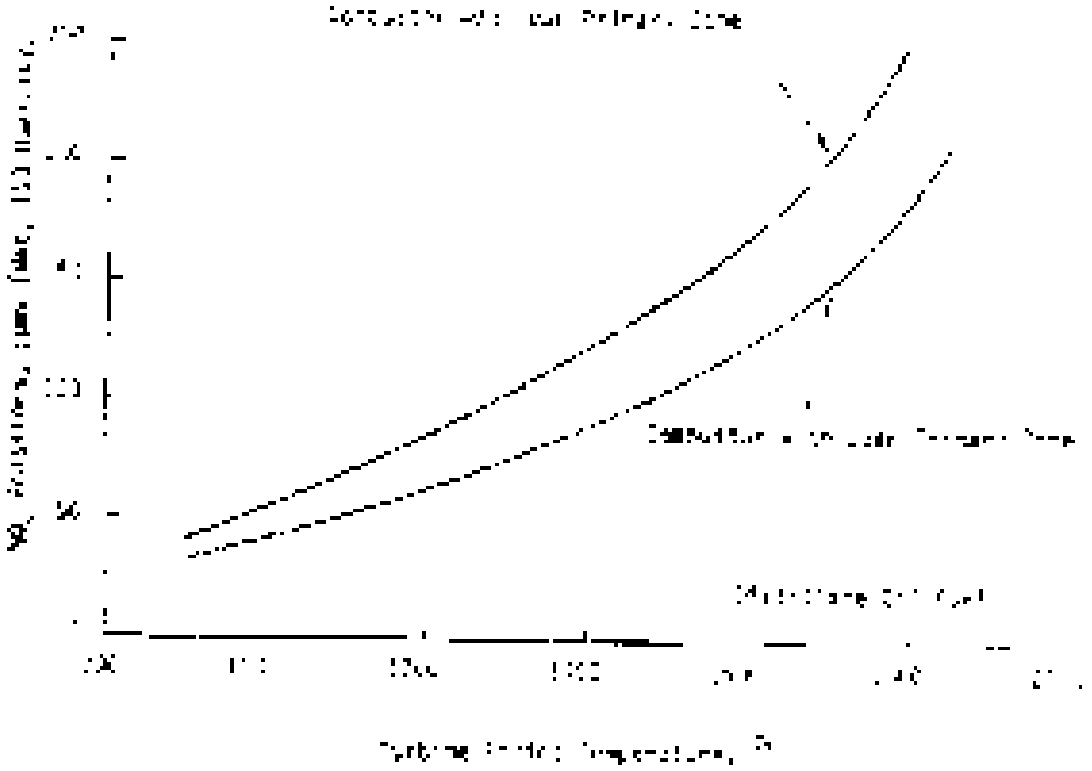


Figure 5-15. Nitrogen oxide emissions versus turbine firing temperature for combustors with and without a lean primary zone.[42]

5 shows a comparison of NO_x emissions from a combustor with a lean primary zone and NO_x emissions from the same combustor without a lean primary zone. At the same firing temperature, NO_x emissions reductions of up to 30 percent are achieved using lean primary zone combustion without increasing CO emissions. Reducing the residence time at elevated temperatures reduces NO_x emissions. One test at 1065°C (1950°F) yielded a reduction in NO_x emissions of 40 percent by reducing the residence time. Carbon monoxide emissions increased from less than 10 to approximately 30 ppm.[42-45]

5.2.2 Lean Premixed Combustors

5.2.2.1 Process Description. In a conventional combustor, the fuel and air are introduced directly into the combustion zone and fuel/air mixing and combustion take place simultaneously. Wide variations in the air-to-fuel ratio (A/F) exist, and combustion of localized fuel-rich pockets produces significant levels of NO_x emissions. In a lean premixed combustor design, the air and fuel is premixed at very lean A/F's prior to introduction into the combustion zone. The excess air in the lean mixture acts as a heat sink, which lowers combustion temperatures. Premixing results in a homogeneous mixture, which minimizes localized fuel-rich zones. The resultant uniform, fuel-lean mixture results in greatly reduced NO_x formation rates.[17]

To achieve NO_x levels below 50 ppmv, referenced to 15 percent O_2, the design A/F approaches the lean flammability limit. To stabilize the flame, ensure complete combustion, and minimize CO emissions, a pilot flame is incorporated into the combustor or burner design. In most designs, the relatively

small amount of air and fuel supplied to this pilot flame is not premixed and the A/F is nearly stoichiometric, so the pilot flame temperature is relatively high. As a result, NO_x emissions from the pilot flame are higher than from the lean premixed combustion.[46]

Virtually all gas turbine manufacturers have implemented lean premixed combustion development programs. Three manufacturers' designs that are available in production turbines are described below.

The first design uses a can-annular combustor and is shown in Figure 5-16

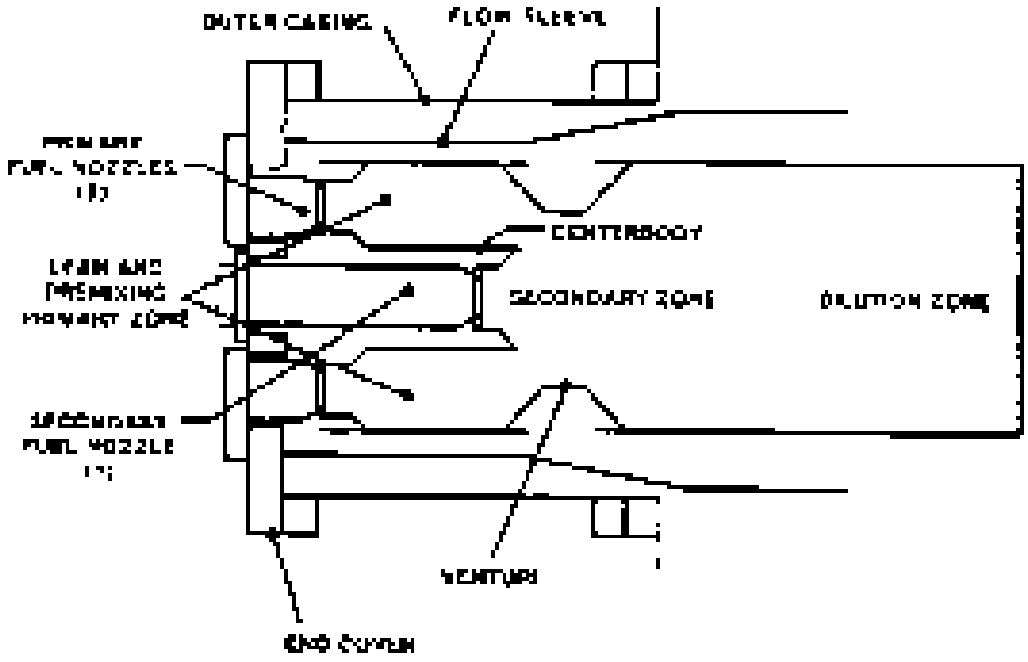


Figure 5-6. Cross-section of a lean premixed can-annular combustor.[47]

. This is a two-stage premixed combustor: the first stage is the portion of the combustor upstream of the venturi section and includes the six primary fuel nozzles; the second stage is the balance of the combustor and includes the single secondary fuel nozzle.[33]

The operating modes for this combustor design are shown in Figure 5-17. For ignition, warmup, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor.

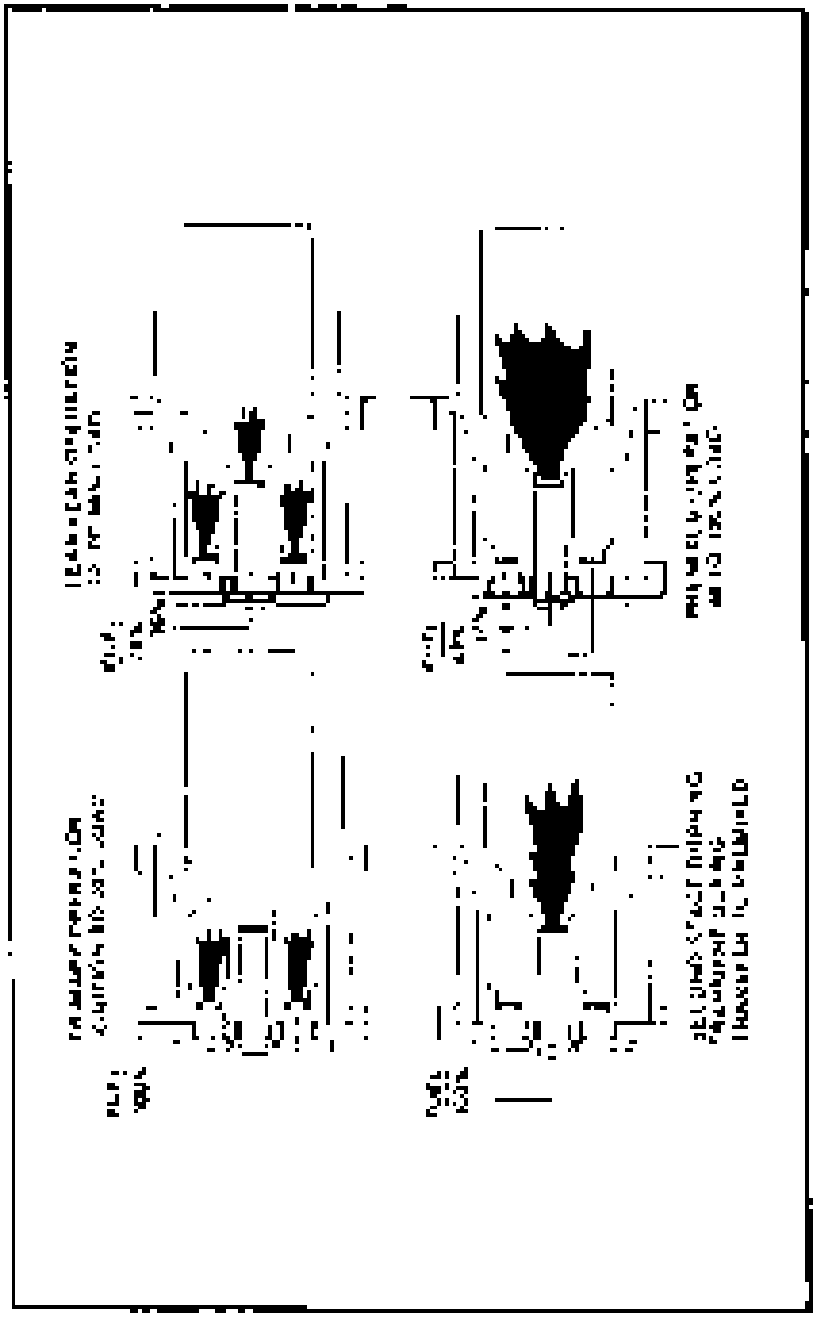


Figure 5-17. Operating modes for a lean premixed can-annular combustor.[33]

Flame is present only in the first stage, and the equivalence ratio is kept as low as stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. Again, the equivalence ratio is kept as low as possible in both stages to minimize NO_x emissions. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.[33]

For operation on distillate oil, fuel is introduced and burned only in the first stage for ignition and for loads up to approximately 50 percent. For loads greater than 50 percent, fuel is introduced and burned in both stages.[33]

Figure 5-18 shows a lean premixed combustor design used by another manufacturer for an annular combustor.

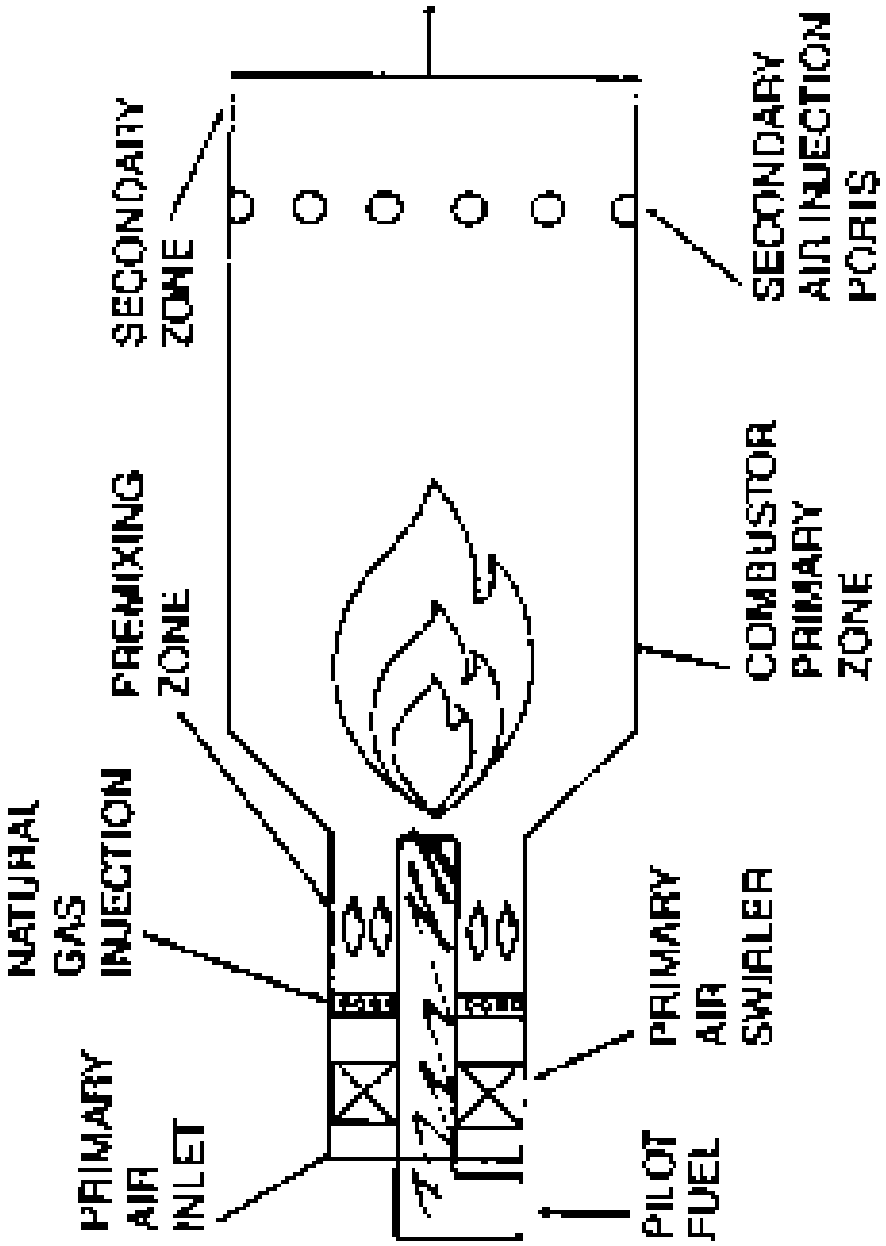


Figure 5-18. Cross-section of lean premixed annular combustion design.[47]

The air and fuel are premixed using a very lean A/F, and the resultant uniform mixture is delivered to the primary combustion zone where combustion is stabilized using a pilot flame. Using one or more mechanical systems to regulate the airflow delivered to the combustor, the premix mode is operable for output loads between 50 and 100 percent. Below 50 percent load, only the pilot flame is operating, and NO_x emissions levels are similar to those for conventional combustors.[46]

Another manufacturer's production low-NO_x design uses a silo combustor. Unlike the can-annular and annular designs, the silo combustor is mounted externally to the turbine and can therefore be modified without significantly affecting the rest of the turbine design, provided the mounting flange to the turbine is unchanged. In addition, this large combustion chamber is fitted with a ceramic lining that shields the metal surfaces from peak flame temperatures. This lining reduces the requirement for cooling air, so more air is available for the combustion process.[17]

This silo low-NO_x combustor design uses six burners, as shown in Figure 5-19

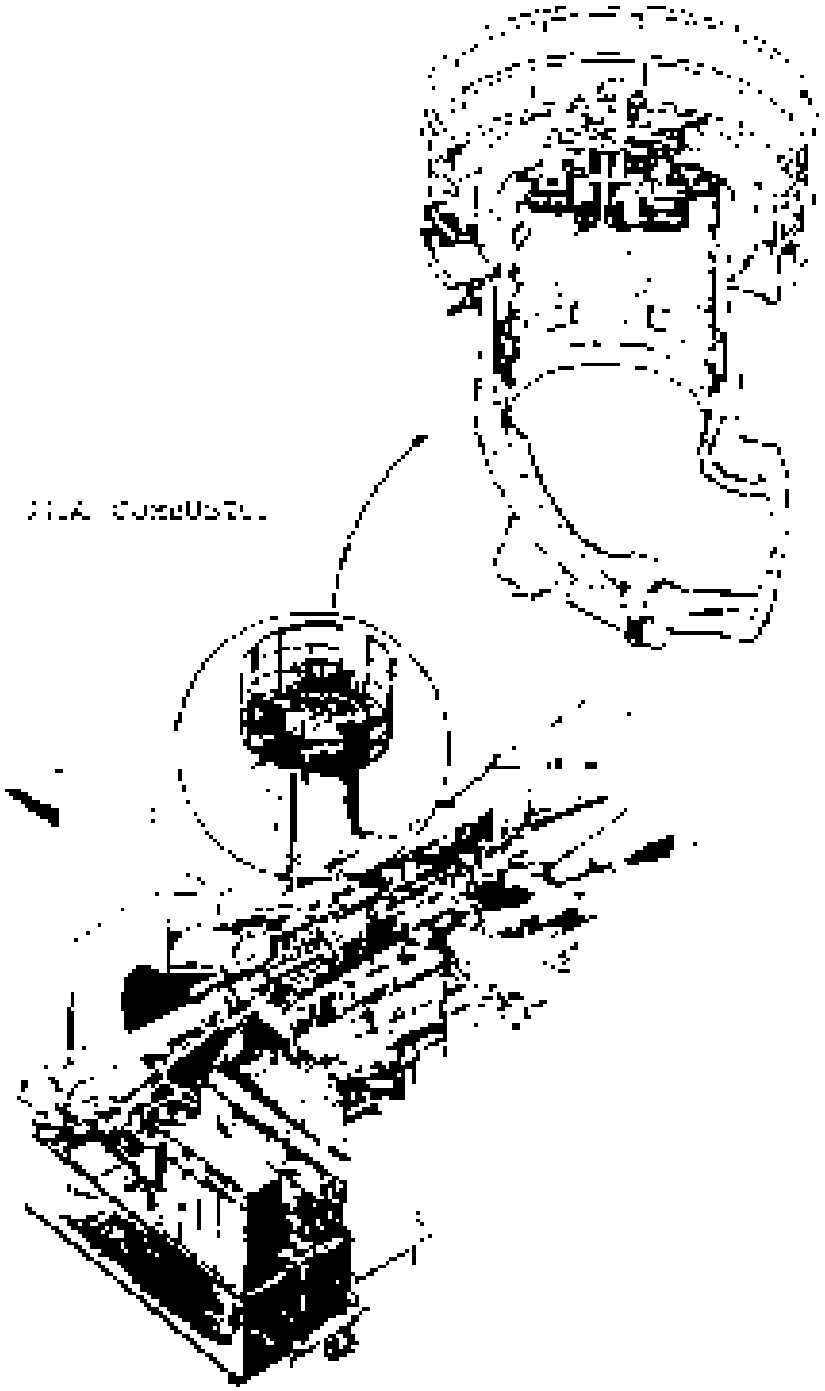


Figure 5-19. Cross-section of a low NO_x silo combustor.[35,48]

. For operation on natural gas, each burner serves to premix the air and fuel to deliver a lean and uniform mixture to the combustion zone. To achieve the lowest possible NO_x emissions, the A/F of the premixed gases is kept very near the lean flammability limit and a pilot flame is used to stabilize the overall combustion process. This burner design is shown in Figure 5-20

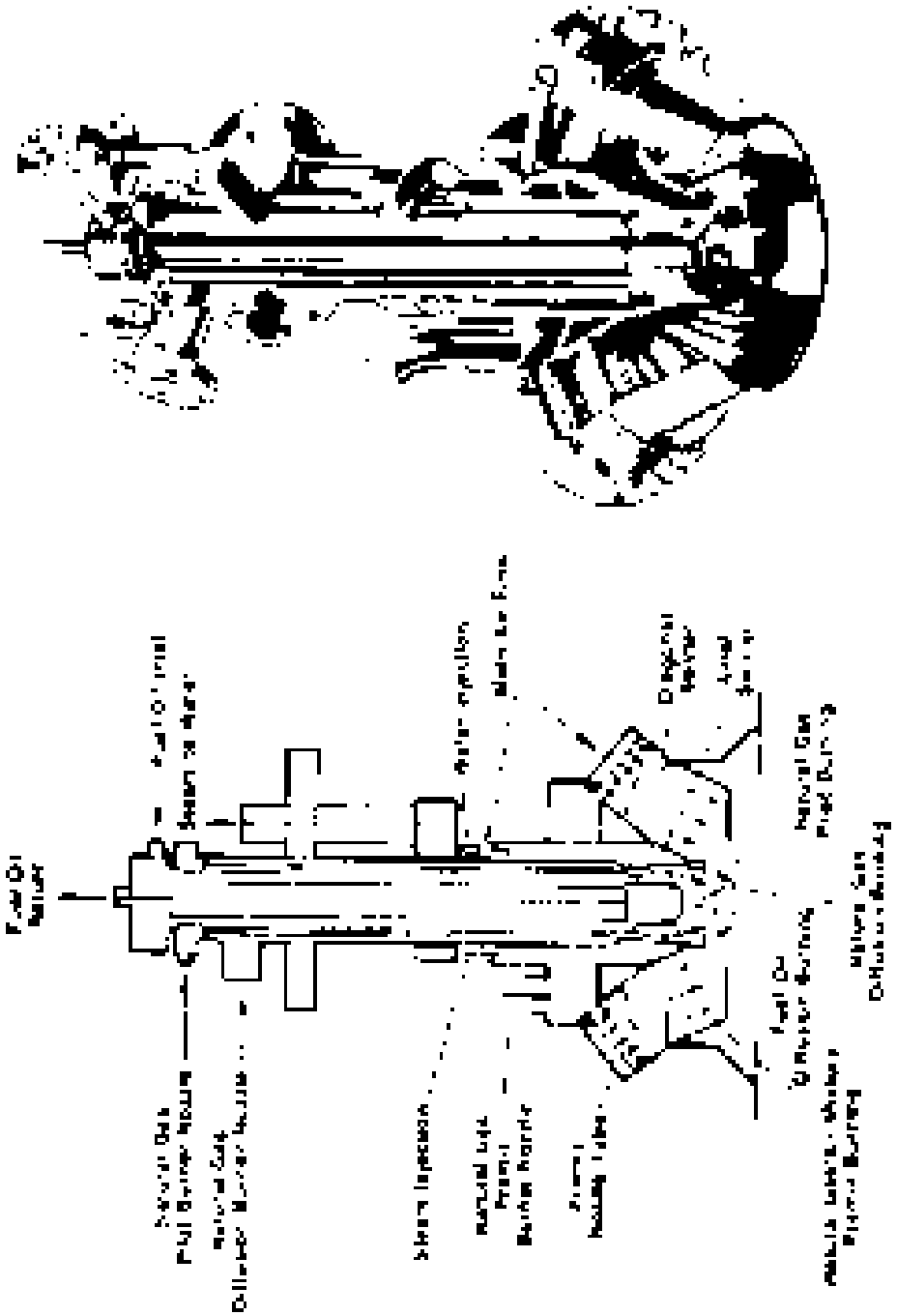


Figure 5-20. Low-NO_x burner for a silo combustor.[48]

. Like the can-annular design, the burner in the silo combustor cannot operate over the full power range of the gas turbine in the premix mode due to inability of the premix mode to deliver suitable A/F's at low power output levels. For this reason, the burners are designed to operate in a conventional diffusion burning mode at startup and low power outputs and switch to a premix burning mode at higher power output levels.

For operation on distillate oil with the current burner design, combustion occurs only in a diffusion mode and there is no premixing of air and fuel.

5.2.2.2 Applicability. As discussed in Section 5.2.2.1, lean premixed combustors apply to can-annular, annular, and silo combustors. This combustion modification is effective in reducing thermal NO_x emissions for both natural gas and distillate oil but is not effective on fuel NO_x. Therefore, lean premixed combustion is not as effective in reducing NO_x levels if high-nitrogen fuels are fired.[49]

The multiple operating modes associated with the percent operating load results in "stepped" NO_x emission levels. To date, low NO_x emission levels occur only at loads greater than 40 to 75 percent.

Lean premixed combustors currently are available for limited models from three manufacturers contacted for this study.[6,17,24] Two additional manufacturers project an availability date of 1993 or 1994 for lean premixed combustors for some turbine models.[11,50] All of these manufacturers state that these lean premixed combustors will be available for retrofit applications.

5.2.2.3 Factors Affecting Performance. The primary factors affecting the performance of lean, premixed combustors are A/F and the type of fuel. To achieve low NO_x emission levels, the A/F must be maintained in a narrow range near the lean flammability limit of the mixture. Lean premixed combustors are designed to maintain this A/F at rated load. At reduced load conditions, the fuel input requirement decreases. To avoid combustion instability and excessive CO emissions that would occur as the A/F reaches the lean flammability limit, all manufacturers' lean premixed combustors switch to a diffusion-type combustion mode at reduced load conditions, typically between 40 and 60 percent load. This switchover to a diffusion combustion mode results in higher NO_x emissions.

Natural gas produces lower NO_x levels than do oil fuels. The reasons for this are the lower flame temperature of natural gas and the ability to premix this fuel with air prior to

delivery into the second combustion stage. For operation on liquid fuels, currently available lean premixed combustor designs require water injection to achieve appreciable NO_x reduction.

5.2.2.4 Achievable NO_x Emission Levels. The achievable controlled NO_x emission levels for lean premixed combustors vary depending upon the manufacturer. At least three manufacturers currently guarantee NO_x emission levels of 25 ppmv, corrected to 15 percent O_2 for most or all of their gas turbines for operation on natural gas fuel without wet injection.[6,17,24] Each of these three manufacturers has achieved controlled NO_x emission levels of less than 10 ppmv at one or more installations in the United States and/or Europe and guarantee this NO_x level for a limited number of their gas turbine models.[51] All three manufacturers offer gas turbines in the 10+ MW (13,400 hp+) range and anticipate that guaranteed NO_x emission levels of 10 ppmv or less will be available for all of their gas turbines for operation on natural gas fuel in the next few years. These low-NO_x combustor designs apply to new turbines and existing installation retrofits.

For gas turbines in the range of 10 MW (13,400 hp) and under, one gas turbine manufacturer offers a guarantee for its lean premixed combustor, without wet injection, of 42 ppmv using natural gas fuel for two of its turbine models for 1994 delivery. This manufacturer states that a controlled NO_x emission level of 25 ppmv has been achieved by in-house testing, and this 25 ppmv level firing natural gas fuel is the goal for all of its gas turbine models, for both new equipment and retrofit applications.[50]

These controlled NO_x emission levels of 9 to 42 ppmv correspond to full output load; at reduced loads, the NO_x levels increase, often in "stepped" fashion in accordance with changes in combustor operation from premixed mode to conventional or diffusion-mode operation (see Section 5.2.2.3). Figure 5-21

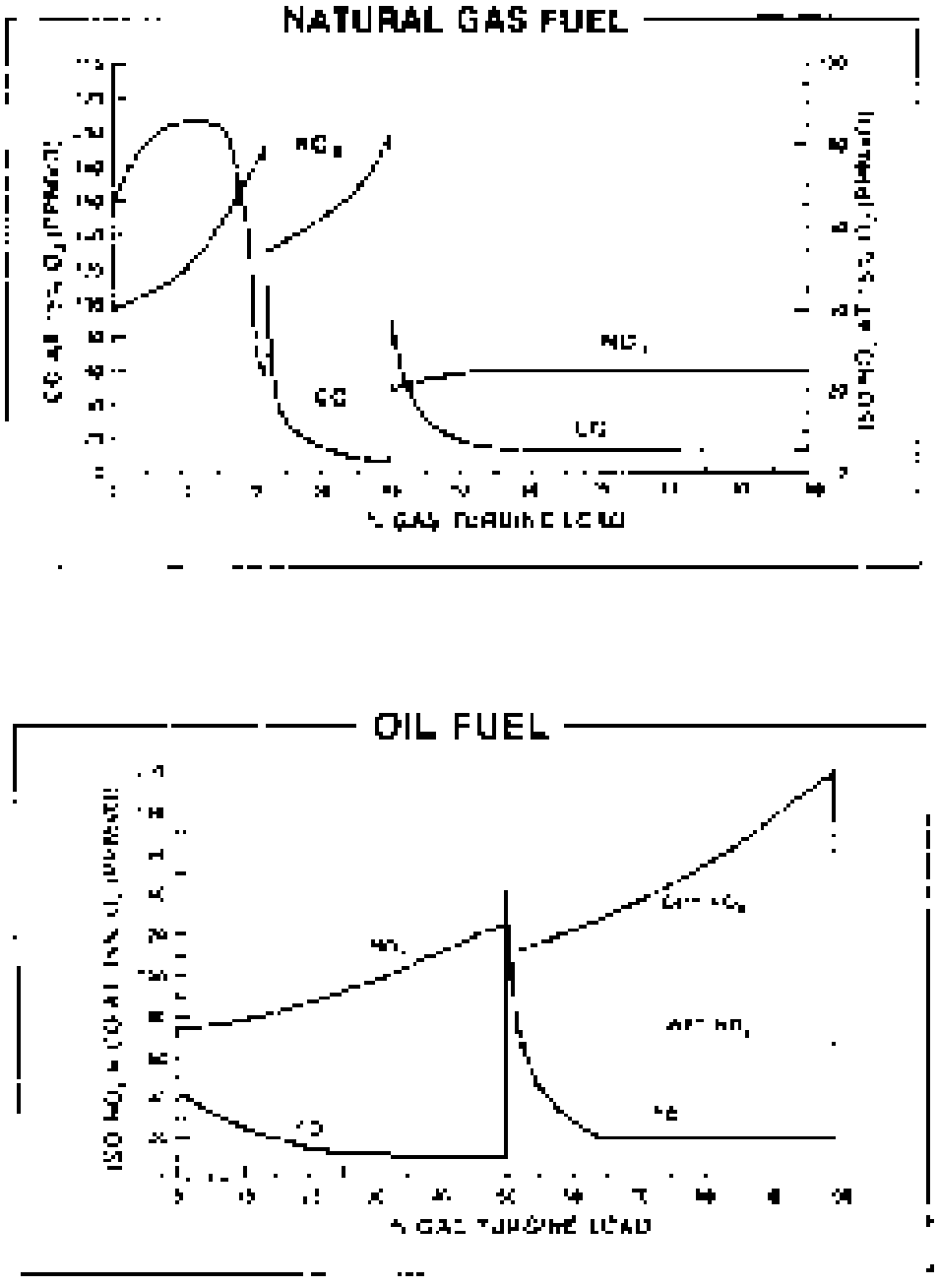


Figure 5-21. "Stepped" NO_x and CO emissions for a low-NO_x can-annular combustor burning natural gas and distillate oil fuels.[47]

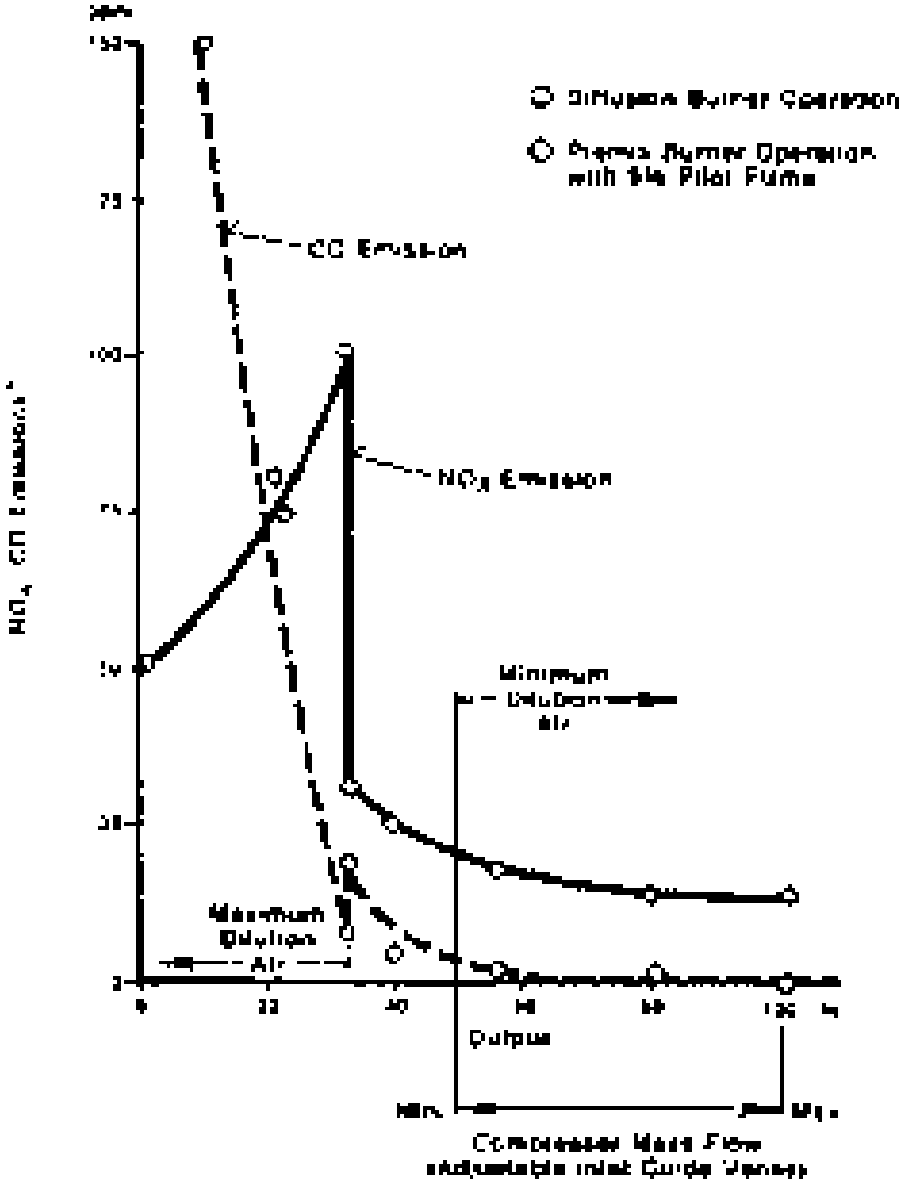


Figure 5-22. "Stepped" NO_x and CO emissions for a low-NO_x silo combustor burning natural gas.[35]

shows these stepped NO_x emissions levels for a can-annular combustor for natural gas and oil fuel operation. Figure 5-22

shows the emissions for a silo combustor operating on natural gas only.

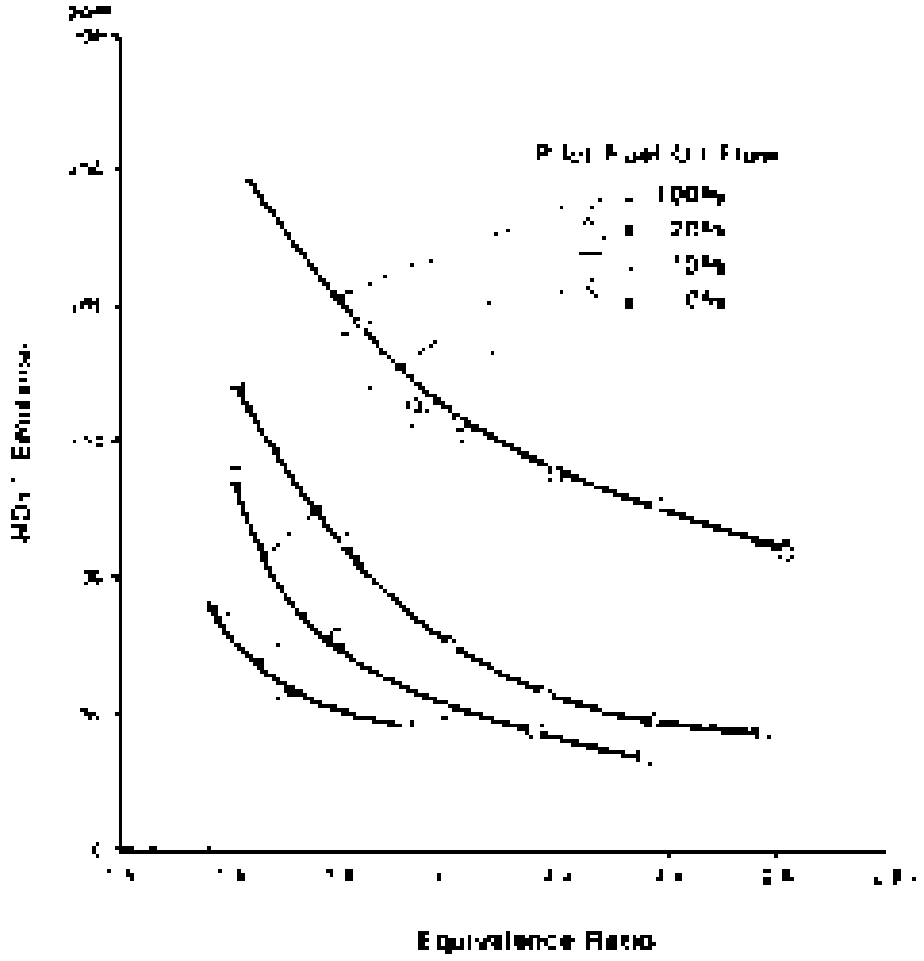


Figure 5-23. Nitrogen oxide emission text results from a lean premix silo combustor firing fuel oil without wet injection.[53]

The emission levels shown in Figures 5-21 and 5-22 correspond to full-scale production turbines currently available from the manufacturers.

Reduced NO_x emissions when burning oil fuel in currently available lean premixed combustor designs have been achieved only with water or steam injection. With water or steam injection, a 65 ppmv NO_x level can be achieved in the turbine with a can-annular combustor design; a 65 ppmv level can also be met with water injection in the turbine with a silo combustor at a WFR of 1.4.[48,52] This 65 ppmv level for lean premixed combustors is higher than the controlled NO_x levels achieved with water injection in oil-fired turbines using a conventional combustor design.

Modification of the existing burner design used in the silo combustor to allow premixing of the oil fuel with air prior to combustion is under development. Tests performed using a 12 MW (16,200 hp) turbine achieved NO_x emission levels below 50 ppmv without wet injection, corrected to 15 percent O_2, compared to uncontrolled levels of 150 ppmv or higher. The NO_x levels, without wet injection, as a function of equivalence ratio are shown in Figure 5-23. The design equivalence ratio at rated load is approximately 2.1. As shown in this figure, NO_x emissions below 50 ppmv were achieved at rated power output at pilot fuel flow levels of 10 percent of the total fuel input.[52]

Site test data for two turbines using silo-type lean premixed combustors, as reported by the manufacturer, are shown in Table 5-12. As this table shows, NO_x emission levels as low as 16.5 ppmv were recorded for using natural gas fuel without

TABLE 5-12. MEASURED NO_x EMISSIONS FOR COMPLIANCE TESTS OF A NATURAL GAS-FUELED LEAN PREMIXED COMBUSTOR WITHOUT WATER INJECTION[22]

Turbine No.	Output, percent of baseline	NO_x emission level, ppmv[a]
1	107	17.7
1	100	16.5
2	100	24.1
2	75	20.4
1	50	22.3
2	50	22.2

[a]In dry exhaust with 15 percent O_2, by volume.

water injection. Subsequent emission tests have achieved levels below 10 ppmv.[51] Corresponding data for operation on oil fuel using only the pilot (diffusion) stage for combustion, and with water injection, is shown in Table 5-13. Levels of NO_x emissions

TABLE 5-13. MEASURED NO_x EMISSIONS FOR OPERATION OF A LEAN PREMIXED COMBUSTOR DESIGN OPERATING IN DIFFUSION MODE ON OIL FUEL WITH WATER INJECTION[22]

Turbine No.	Output, percent of baseload	NO_x emission level, ppmv[a]
1	Peak	69.3
2	Peak	53.6
1	100	59.9
2	100	51.6
1	75	54.3
2	75	49.2
2	50	54.8

[a]In dry exhaust with 15 percent O_2, by volume.

at base load for No. 2 fuel oil are between 50 and 60 ppmv.

Based on information provided by turbine manufacturers, the potential NO_x reductions using currently available lean premixed

combustors are shown in Table 5-14. As this table indicates, NO_x emission reductions range from 14.7 tons/yr for a 1.1 MW (1,480 hp) turbine to 10,400 tons/yr

TABLE 5-14. POTENTIAL NO_x REDUCTIONS FOR GAS TURBINES USING LEAN PREMIXED COMBUSTORS

Turbine model	Power output, MW	NO_x emissions					
		Uncontrolled		Controlled		NO_x reduction	
		Gas fuel, ppmv	Oil fuel, ppvm	Gas fuel, ppmv	Oil fuel, ppmv	Gas fuel, tons/yr[a]	Oil fuel, tons/yr[a b]
Saturn[c]	1.1	99	150	42	NA[d]	14.7	NA[d]
Centaur T-4500[c]	3.3	130	179	42	NA[d]	59.5	NA[d]
Centaur "H"[c]	4.0	105	160	42	NA[d]	49.8	NA[d]
Taurus[c]	4.5	114	168	42	NA[d]	62.4	NA[d]
Mars T-12000[c]	8.8	178	267	42	NA[d]	212	NA[d]
Mars T-14000[c]	10.0	199	NA[d]	42	NA[d]	270	NA[d]
MS6001B	39.0	148	267	25/9[e]	65	829/937	1,139
MS7001E	84.7	154	228	25/9[e]	65	1,820/2,050	2,360
MS7001F	161	210	353	25	65	4,540	5,190
MS9001E	125	161	241	25/9[e]	65	2,740/3,060	3,490
MS9001F	229	210	353	25	65	6,500	7,250
GT10	22.6	150	200	25	42	476	620
GT11N	83.3	390	560	25/9[e]	42	5,070/5,290	7,360
V84.2	105	212	360	25/9[e]	NA[f]	3,030/3,290	NA[f]
V94.2	153	212	360	9[e]	NA[f]	4,410/4,780	NA[f]
V64.3	61.5	380	530	42	NA[d]	3,210	NA[d]
V84.3[c]	141	380	530	42	NA[d]	7,230	NA[d]
V94.3[e]	204	380	530	42	NA[d]	10,400	NA[d]

[a]Based on 8,000 hours operation per year.
[b]Requires water or steam injection.
[c]Scheduled availability is 1994 for natural gas fuel.
[d]NA = Data not available.
[e]Standard NO_x guarantee is 25 ppmv. Manufacturers offer guaranteed NO_x levels as low as 9 ppmv for these turbines.
[f]Scheduled availability 1993 for oil fuel without water injection. Reference 17.

for a 204 MW (274,000 hp) turbine for operation on natural gas without wet injection. Corresponding NO_x emission reductions for operation on oil fuel, with water injection, range from 620 tons/yr for a 22.6 MW (30,300 hp) turbine to 7,360 tons/yr for an 83.3 MW (112,000 hp) turbine.

Limited data from two manufacturers showing the impact of lean premixed combustor designs on CO emissions are shown in Table 5-15.

TABLE 5-15. COMPARISON OF NO_x AND CO EMISSIONS FOR STANDARD VERSUS LEAN PREMIXED COMBUSTORS FOR TWO MANUFACTURERS' TURBINES[46,54]

	Emissions, ppmv, referenced to 15 percent O_2[a]				
		Standard combustor		Lean premixed combustor	
GT Model	Power output, MW	NO_x	CO	NO_x	CO
Centaur H	4.0	105	15	25-42	50[b]
Mars T-14000	10.0	199	5.5	25-42	50[b]
MS6001B	39.0	148	10	9	25
MS7001E	84.7	154	10	9	25
MS9001E	125	161	10	9	25
MS7001F	161	210	25	25	15
MS9001F	229	210	25	25	15

[a]For operation at ISO conditions using natural gas fuel.

[b]Maximum design goal for CO emissions. Most in-house test configurations have achieved CO emission levels between 5 and 25 ppmv.

For natural gas-fueled turbines with rated outputs of 10 MW (13,400 hp) or less, controlled NO_x emission levels of 25 to 42 ppmv result in a rise in CO emission levels from 25 ppmv or less to as high as 50 ppmv.[43] For turbines above 10 MW (13,400 hp), controlled NO_x emission levels of 9 ppmv result in a rise in CO emissions from 10 to 25 ppmv for natural gas fuel. Conversely, for controlled NO_x emission levels of 25 ppmv, the CO emissions drop from 25 to 15 ppmv.[51] For one manufacturer's lean premixed silo combustor design, CO emissions at rated load are less than 5 ppmv, as shown previously in Figure 5-21. This limited data suggest that the effect of lean premixed combustors on CO emissions depends upon the specific combustor design and the controlled NO_x emission level.

The emission levels shown in Table 5-15 correspond to rated power output. Like NO_x emission levels, CO emissions change with changes in combustor operating mode at reduced power output. The "stepped" effect on CO emissions is shown in Figures 5-21 and 5-22, shown previously.

Operation on oil fuel with wet injection, shown previously in Figure 5-21, shows CO emission levels of 20 ppmv. Additional CO emission data were not available for operation on oil fuel with water injection in lean premixed combustors. Developmental tests for operation on oil fuel without wet injection in a silo combustor are presented in Figure 5-24

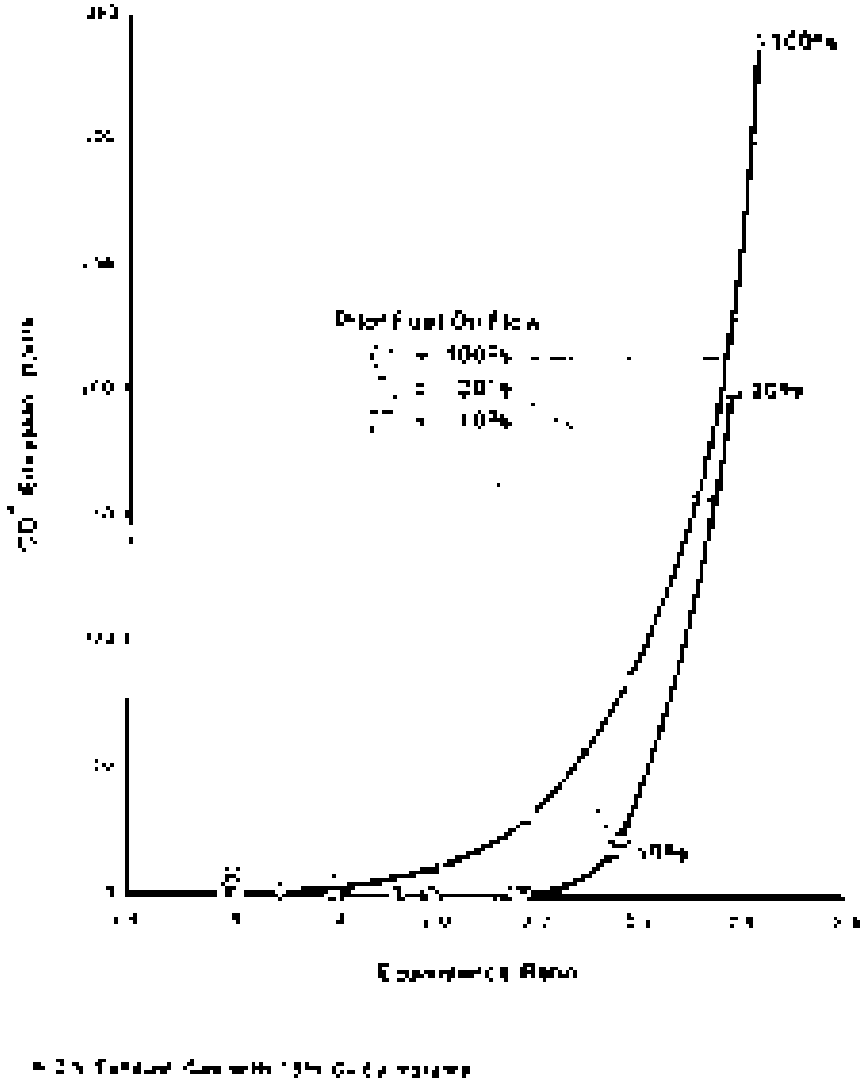


Figure 5-24. The CO emission test results from a lean premix silo combustor firing fuel oil without wet injection.

. At rated load, shown in this figure at an equivalence ratio of approximately 2.1, CO emissions are less than 10 ppmv, corrected to 15 percent $O_{2,}$

and are in the range of 0 to 2 ppmv for a pilot oil fuel flow of 10 percent (representing 10 percent of the total fuel flow).[53] This 10 percent pilot fuel flow corresponds to controlled NO_x emission levels below 50 ppmv, as shown previously in Figure 5-22. No data for HC emissions were available for lean premixed burner designs.

5.2.3 Rich/Quench/Lean Combustion

5.2.3.1 Process Description. Rich/quench/lean (RQL) combustors burn fuel-rich in the primary zone and fuel-lean in the secondary zone. Incomplete combustion under fuel-rich conditions in the primary zone produces an atmosphere with a high concentration of CO and hydrogen (H_2). The CO and H_2 replace some of the oxygen normally available for NO_x formation and also act as reducing agents for any NO_x formed in the primary zone. Thus, fuel nitrogen is released with minimal conversion to NO_x. The lower peak flame temperatures due to partial combustion also reduce the formation of thermal NO_x.[55]

As the combustion products leave the primary zone, they pass through a low-residence-time quench zone where the combustion products are rapidly diluted with additional combustion air or water. This rapid dilution cools the combustion products and at the same time produces a lean A/F. Combustion is then completed under fuel-lean conditions. This secondary lean combustion step minimally contributes to the formation of fuel NO_x because most of the fuel nitrogen will have been converted to N_2 prior to the lean combustion phase. Thermal NO_x is minimized during lean combustion due to the low flame temperature.[55]

5.2.3.2 Applicability. The RQL combustion concept applies to all types of gas turbines. None of the manufacturers contacted for this study, however, currently have this design available for their production turbines. This may be due to lack of demand for this design due to the current limited use of high-nitrogen-content fuels in gas turbines.

5.2.3.3 Factors Affecting Performance. The NO_x emissions from RQL combustors are affected primarily by the equivalence ratio in the primary combustion zone and the quench airflow rate.

Careful selection of equivalence ratios in the fuel-rich zone will minimize both thermal and fuel NO_x formation. Further NO_x reduction is achieved with increasing quench airflow rates, which serve to reduce the equivalence ratio in the secondary (lean) combustion stage.

5.2.3.4 Achievable NO_x Emissions Levels Using Rich/Quench/Lean Combustion. The RQL staged combustion has been demonstrated in rig tests to be effective in reducing both thermal NO_x and fuel NO_x. As shown in Figure 5-25, NO_x emissions are reduced by 40 to 50 percent in a test rig burning diesel fuel.

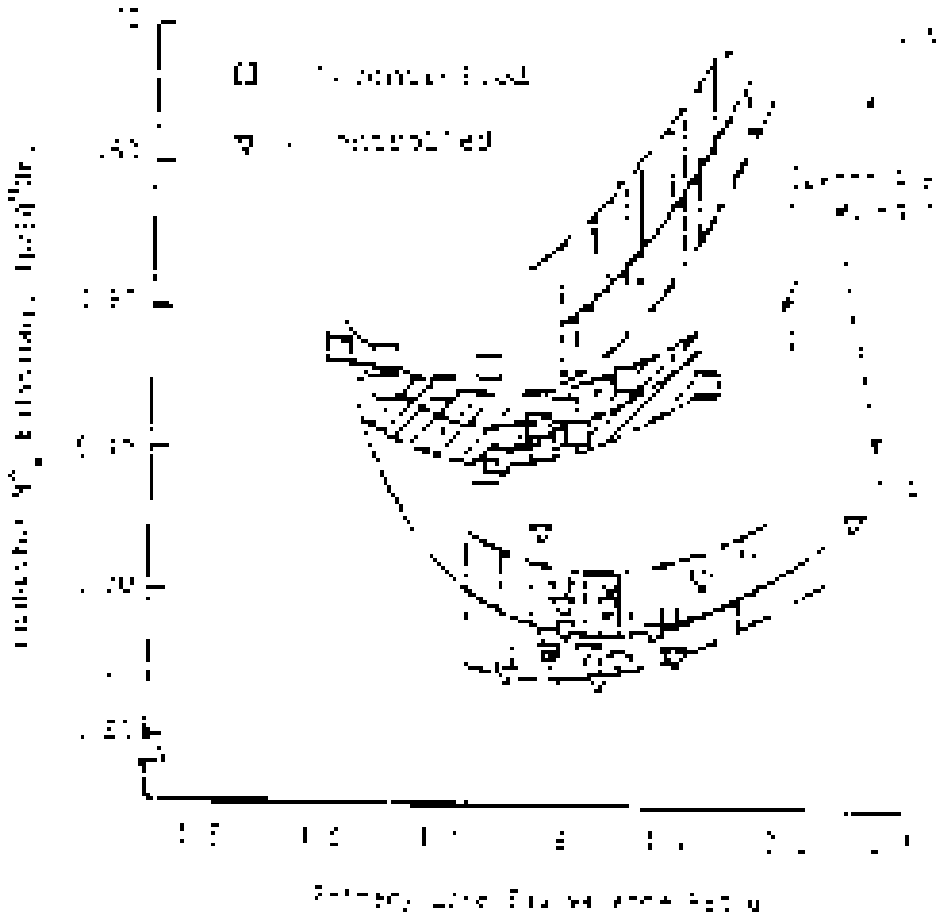


Figure 5-25. Nitrogen oxide emissions versus primary zone equivalence ratio for a rich/quench/lean combustor firing distillate oil.[56]

At an equivalence ratio of 1.8, the NO_x emissions can be reduced from 0.50 to 0.27 lb/MMBtu by increasing the quench airflow from 0.86 to 1.4 kg/sec. Data were not available to convert the NO_x emissions figures to ppmv. The effectiveness of rich/lean staged combustion in reducing fuel NO_x when firing high-FBN fuels is shown in Figure 5-26.

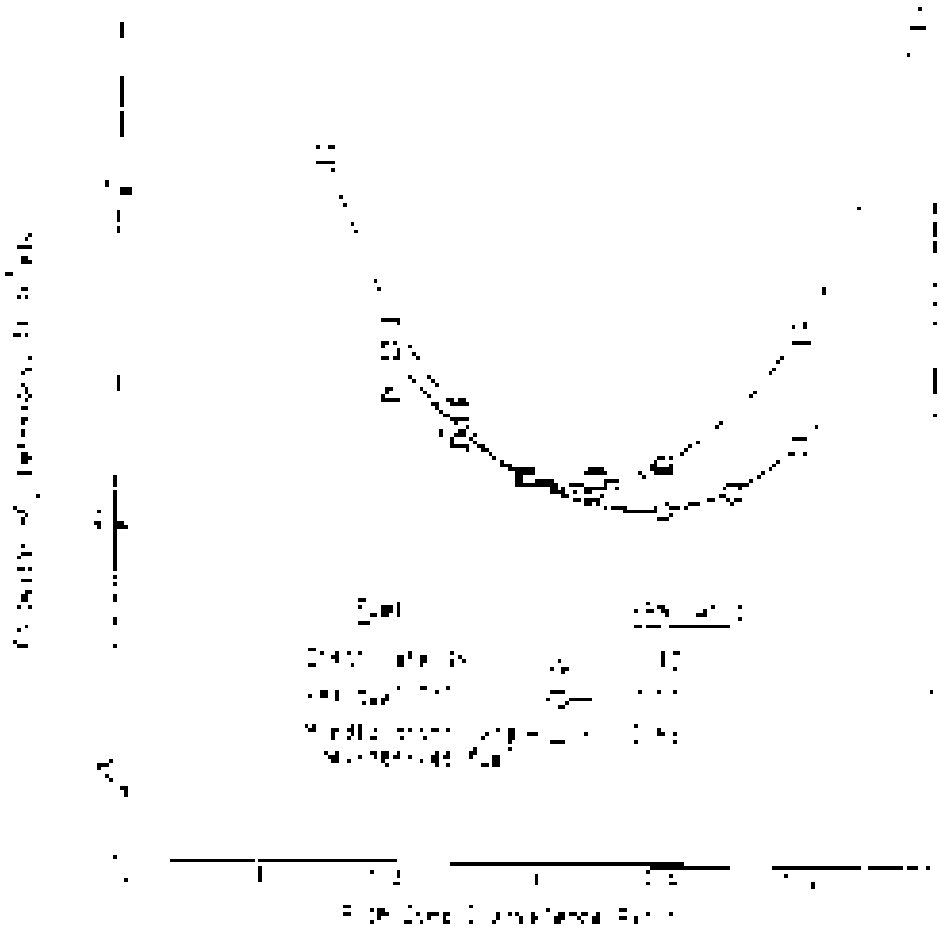


Figure 5-26. Effects of fuel bound nitrogen (FBN) content of NO_x emissions for a rich/quench/lean combustor.[57]

Increasing the FBN content from 0.13 to 0.88 percent has little impact on the total NO_x formation at an operating equivalence ratio of 1.3 to 1.4. Tests on other rich/lean combustors indicate fuel nitrogen conversions to NO_x of about 7 to 20 percent.[58,59] These fuel nitrogen conversions represent a fuel NO_x emission reduction of approximately 50 to 80 percent.

One manufacturer has tested an RQL combustor design in a 4 MW (5,360 hp) gas turbine fueled with a finely ground coal and water mixture. The coal partially combusts in a fuel-rich zone at temperatures of 1650°C (3000°F), with low O_2 levels and an extremely short residence time. The partially combusted products are then rapidly quenched with water, cooling combustion temperatures to inhibit thermal NO_x formation. Additional combustion air is then introduced, and combustion is completed under fuel-lean conditions. In tests at the manufacturer's plant, cosponsored by the U. S. Department of Energy, a NO_x emission level of 25 ppmv at 15 percent O_2 was achieved. This combustor design can also be used with natural gas and oil fuels. Single-digit NO_x emission levels are reported for operation on

natural gas fuel. This combustor design is not yet available for production turbines.[60]

5.3 SELECTIVE CATALYTIC REDUCTION

Selective catalytic reduction (SCR) is an add-on NO_x control technique that is placed in the exhaust stream following the gas turbine. Over 100 gas turbine installations use SCR in the United States.[61] An SCR process description, the applicability of SCR for gas turbines, the factors affecting SCR performance, and the achievable NO_x reduction efficiencies are discussed in this section.

5.3.1 Process Description

The SCR process reduces NO_x emissions by injecting ammonia into the flue gas. The ammonia reacts with NO_x in the presence of a catalyst to form water and nitrogen. In the catalyst unit, the ammonia reacts with NO_x primarily by the following equations:[62]

$$NH_3 + NO + 1/4\ O_2 \rightarrow N_2 + 3/2\ H_2O;\ \text{and}$$

$$NH_3 + 1/2\ NO_2 + 1/4\ O_2 \rightarrow 3/2\ N_2 + 3/2\ H_2O.$$

The catalyst's active surface is usually either a noble metal, base metal (titanium or vanadium) oxide, or a zeolite-based material. Metal-based catalysts are usually applied as a coating over a metal or ceramic substrate. Zeolite catalysts are typically a homogenous material that forms both the active surface and the substrate. The geometric configuration of the catalyst body is designed for maximum surface area and minimum obstruction of the flue gas flow path to maximize conversion efficiency and minimize back-pressure on the gas turbine. The most common catalyst body configuration is a monolith, "honeycomb" design, as shown in Figure 5-27.

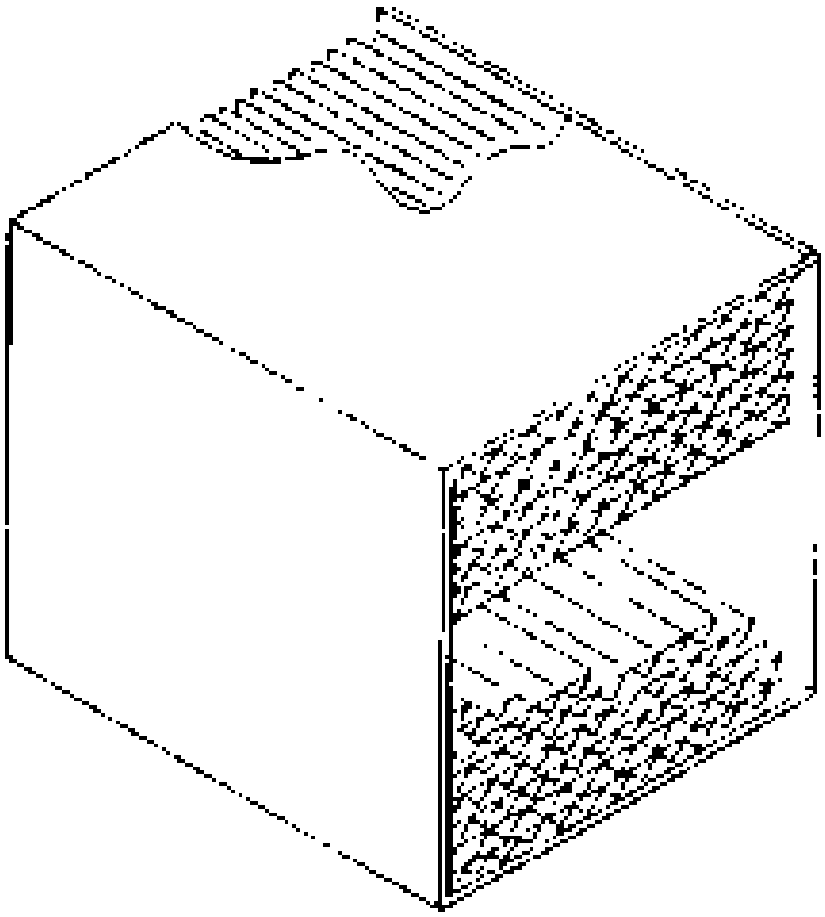


Figure 5-27. Cutaway view of a typical monolith catalyst body with honeycomb configuration.[62]

An ammonia injection grid is located upstream of the catalyst body and is designed to disperse the ammonia uniformly throughout the exhaust flow before it enters the catalyst unit. In a typical ammonia injection system, anhydrous ammonia is drawn from a storage tank and evaporated using a steam- or electric-heated vaporizer. The vapor is mixed with a pressurized carrier gas to provide both sufficient momentum through the

injection nozzles and effective mixing of the ammonia with the flue gases. The carrier gas is usually compressed air or steam, and the ammonia concentration in the carrier gas is about 5 percent.[62]

An alternative to using the anhydrous ammonia/carrier gas system is to inject an a aqueous ammonia solution. This system is currently not as common but removes the potential safety hazards associated with transporting and storing anhydrous ammonia and is often used in installations with close proximity to populated areas.[61,62]

The NH_3/NO_x ratio can be varied to achieve the desired level of NO_x reduction. As indicated by the chemical reaction equations listed above, it takes one mole of NH_3 to reduce one mole of NO, and two moles of NH_3 to reduce one mole of NO_2. The NO_x composition in the flue gas from a gas turbine is over 85 percent NO, and SCR systems generally operate with a molar NH_3/NO_x ratio of approximately 1.0.[63] Increasing this ratio will further reduce NO_x emissions but will also result in increased unreacted ammonia passing through the catalyst and into the atmosphere. This unreacted ammonia is known as ammonia slip.

5.3.2 Applicability of SCR for Gas Turbines

Selective catalytic reduction applies to all gas turbine types and is equally effective in reducing both thermal and fuel NO_x emissions. There are, however, factors that may limit the applicability of SCR.

An important factor that affects the performance of SCR is operating temperature. Gas turbines that operate in simple cycle have exhaust gas temperatures ranging from approximately 450° to 540°C (850° to 1000°F). Base-metal catalysts have an operating temperature window for clean fuel applications of approximately 260° to 400°C (400° to 800°F). For sulfur-bearing fuels that produce greater than 1 ppm SO_3 in the flue gas, the catalyst operating temperature range narrows to 315° to 400°C (600° to 800°F). The upper range of this temperature window can be

increased using a zeolite catalyst to a maximum of 590°C (1100°F).[64]

Base metal catalysts are most commonly used in gas turbine SCR applications, accounting for approximately 80 percent of all U.S. installations, and operate in cogeneration or combined cycle applications. The catalyst is installed within the HRSG, where the heat recovery process reduces exhaust gas temperatures to the proper operating range for the catalyst. The specific location of the SCR within the HRSG is application-specific; Figure 5-28 shows two possible SCR locations.

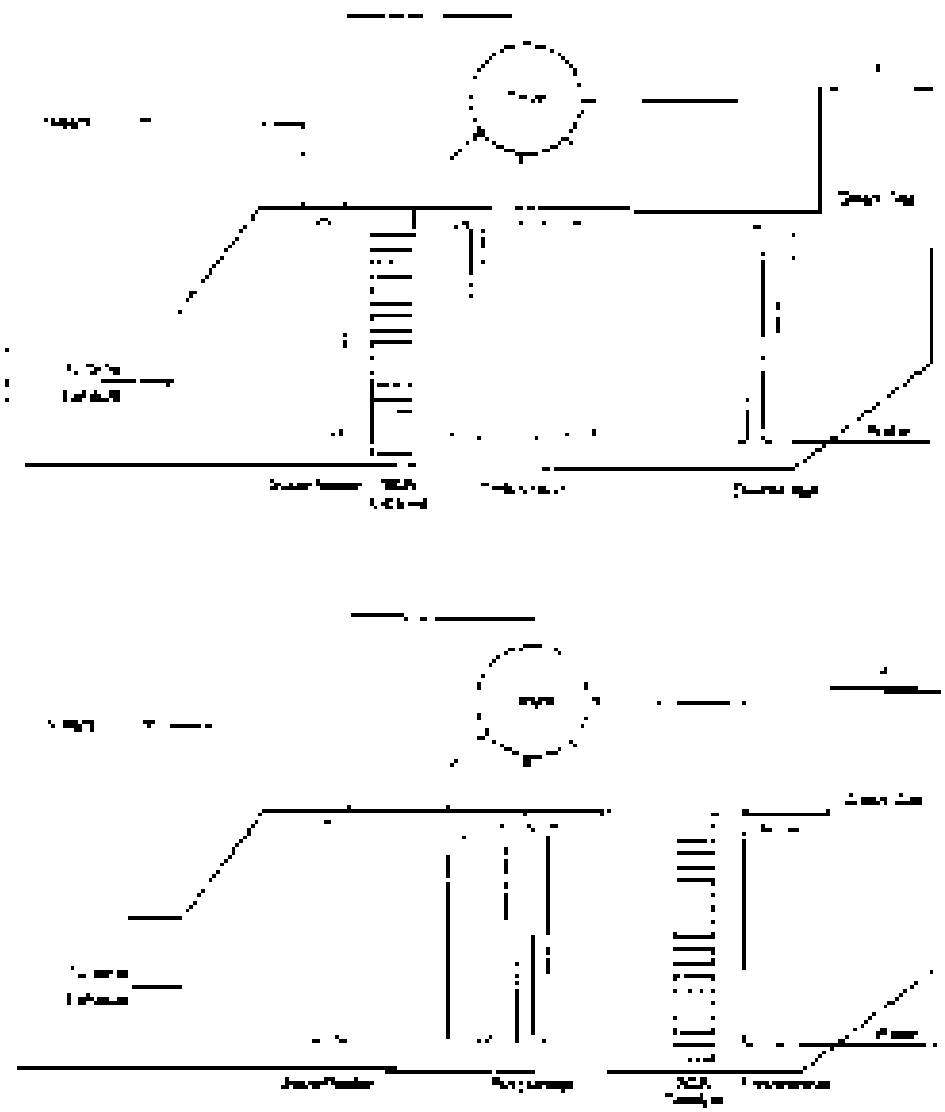


Figure 5-28. Possible locations for SCR unit in HRSG.[62]

In addition to the locations shown, the catalyst may also be located within the evaporator section of the HRSG.

As noted above, zeolite catalysts have a maximum operating temperature range of up to 590°C (1100°F), which is compatible with simple cycle turbine exhaust temperatures. To date, however, there is only one SCR installation operating with a zeolite catalyst directly downstream of the turbine. This catalyst, commissioned in December 1989, has an operating range of 260° to 515°C (500° to 960°F) and operates approximately 90 percent of the time at temperatures above 500°C (930°F).[65]

Another consideration in determining the applicability of SCR is complications arising from sulfur-bearing fuels. The sulfur content in pipeline quality natural gas is negligible, but distillate and residual oils as well as some low-Btu fuel gases such as coal gas have sulfur contents that present problems when used with SCR systems. Combustion of sulfur-bearing fuels produces SO_2 and SO_3 emissions. A portion of the SO_2 oxidizes to SO_3 as it passes through the HRSG, and base metal catalysts have an SO_2-to-SO_3 oxidation rate of up to five percent.[64] In addition, oxidation catalysts, when used to reduce CO emissions, will also oxidize SO_2 to SO_3 at rates of up to 50 percent.[66]

Unreacted ammonia passing through the catalyst reacts with SO_3 to form ammonium bisulfate (NH_4HSO_4) and ammonium sulfate [$(NH_4)_2\ SO_4$] in the low-temperature section of the HRSG. The rate of ammonium salt formation increases with increasing levels of SO_3 and NH_3, and the formation rate increases with decreasing

temperature. Below 200°C (400°F), ammonium salt formation occurs with single-digit ppmv levels of SO_3 and NH_3.[66]

The exhaust temperature exiting the HRSG is typically in the range of 150° to 175°C (300° to 350°F), so ammonium salt formation typically occurs in the low-temperature section of the HRSG.[66] Ammonium bisulfate is a sticky substance that over time corrodes the HRSG boiler tubes. Additionally, it deposits on both the boiler and catalyst bed surfaces, leading to fouling and plugging of these surfaces. These deposits result in increased back pressure on the turbine and reduced heat transfer efficiency in the HRSG. This requires that the HRSG be removed from service periodically to water-wash the affected surfaces. Ammonium sulfate is not corrosive, but like ammonium bisulfate, it deposits on the HRSG surfaces and contributes to plugging and fouling of the heat transfer system.[33]

Formation of ammonium salts can be avoided by limiting the sulfur content of the fuel and/or limiting the ammonia slip. Low SO_2-to-SO_3 oxidizing catalysts are also available. Base metal catalysts are available with oxidation rates of less than 1 percent, but these low oxidation formulas also have lower NO_x reduction activity per unit volume and therefore require a greater catalyst volume to achieve a given NO_x reduction level. Zeolite catalysts are reported to have intrinsic SO_2-to-SO_3 oxidation rates of less than 1 percent.[64,66] As stated above, pipeline-quality natural gas has negligible sulfur content, but some sources of natural gas contain H_2S, which may contribute to ammonium salt formation. For oil fuels, even the lowest-sulfur distillate oil or liquid aviation fuel contains sulfur levels that can produce ammonium salts. According to catalyst vendors, SCR systems can be designed for 90 percent NO_x reduction and 10 ppm or lower NH_3 slip for sulfur-bearing fuels up to 0.3 percent by weight.[64] Continuous emission monitoring equipment has been developed for NH_3, and may be instrumental in regulating ammonia injection to minimize slip.[67]

To date, there is limited operating experience using SCR with oil-fired gas turbine installations. One combined cycle

installation using oil fuel, a United Airlines facility in San Francisco installed in 1985, experienced fuel-related catalyst problems and now uses only natural gas fuel.[33] In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now available, however, and catalyst formulation improvements have proven effective in resisting performance degradation with oil fuels in Europe and Japan, where catalyst life in excess of 4 to 6 years has been achieved, versus 8 to 10 years with natural gas fuel.[64] A zeolite catalyst installed on a 5 MW (6710 hp) dual fuel reciprocating engine in the northeastern United States has operated for over 3 years and burned approximately 600,000 gallons of diesel fuel while maintaining a NO_x reduction efficiency of greater than 90 percent.[3]

In its guidance to member states, NESCAUM recommends that SCR be considered for NO_x reduction in dual-fueled turbine applications. There are four combined cycle gas turbines installations operating with SCR in the northeast United States burning natural gas as the primary fuel with oil fuel as a back-up.[3] These installations, listed in Table 5-16,

TABLE 5-16. GAS TURBINE INSTALLATIONS IN THE NORTHEASTERN UNITED STATES WITH SCR AND PERMITTED FOR BOTH NATURAL GAS AND OIL FUELS[3]

Installation	State	Gas turbine model	Output, MW[a]	NO_x emissions, ppmv (gas fuel/oil fuel)		
				Uncontrolled[b]	Wet injection[b]	Wet injection + SCR[c]
Altresco-Pittsfield	MA	MS6001	38.3	148/267	42/65	9/18[d e]
Cogen Technologies	NJ	MS6001	38.3	148/267	42/65	15/65[f]
Ocean State Power	RI	MS7001E	83.5	154/277	42/65	9/42[f]
Pawtucket Power	RI	MS6001	38.3	148/267	42/65	9/18[d]

[a]Power output for a single gas turbine. Installation power output is higher due to multiple units and/or combined cycle operation.

[b]Per manufacturer at ISO conditions.

[c]Operating permit limits.

[d]This installation requires the SCR system to be operational when burning oil fuel.

[e]This installation operated 185 hours on oil fuel in 1991, burning approximately 354,000 gallons of oil fuel.

[f]Ammonia injection is shut down during operation on oil fuel.

began operating recently and have limited hours of operation on oil fuel. As indicated in the table, two of these installations shut down the ammonia injection when operating on oil fuel to prevent potential operating problems arising from sulfur-bearing fuels. Permits issued more recently in this region for other dual-fuel installations, however, require that the SCR system be operational on either fuel.[3]

A final consideration for SCR is catalyst masking or poisoning agents. Natural gas is considered clean and free of contaminants, but other fuels may contain agents that can degrade catalyst performance. For refinery, field, or digester gas fuel applications, it is important to have an analysis of the fuel and properly design the catalyst for any identified contaminants. Arsenic, iron, and silica may be present in field gases, along with zinc and phosphorus. Catalyst life with these fuels depends upon the content of the gas and is a function of the initial

design parameters. With oil fuels, in addition to the potential for ammonium salt formation, it is important to be aware of heavy metal content. Particulates in the flue gas can also mask the catalyst.[64]

Selective catalytic reduction may not be readily applicable to gas turbines firing fuels that produce high ash loadings or high levels of contaminants because these elements can lead to fouling and poisoning of the catalyst bed. However, because gas turbines are also subject to damage from these elements, fuels with high levels of ash or contaminants typically are not used.

Coal, while not currently a common fuel for turbines, has a number of potential catalyst deactivators. High dust concentrations, alkali, earth metals, alkaline heavy metals, calcium sulfate, and chlorides all can produce a masking or blinding effect on the catalyst. High dust can also erode the catalyst. Erosion commonly occurs only on the leading face of the catalyst. Airflow deflectors and dummy layers of catalyst can be used to straighten out the airflow and reduce erosion. There is currently no commercial U.S. experience with coal. In Japan, which burns low-sulfur coal with moderate dust levels, catalyst life has been 5 years or more without replacement. In Germany, with high dust loadings, the experience has also been 5 years or more.[64]

Masking agents deposit on the surface of the catalyst, forming a barrier between the active catalyst surface and the exhaust gas, inhibiting catalytic activity. Poisoning agents chemically react with the catalyst and render the affected area inactive. Masking agents can be removed by vacuuming or by using soot blowers or superheated steam. Catalysts cleaned in this manner can recover greater than 90 percent of the original reduction activity. The effects of poisoning agents, however, are permanent and the affected catalyst surface cannot be regenerated.[64]

Retrofit applications for SCR may require the addition of a heat exchanger for simple cycle installations, and replacement or extensive modification of the existing HRSG in cogeneration and

combined cycle applications to accommodate the catalyst body. For these reasons, retrofit applications for SCR could involve high capital costs.

5.3.3 Factors Affecting SCR Performance

The NO_x reduction efficiency for an SCR system is influenced by catalyst material and condition, reactor temperature, space velocity, and the NH_3/NO_x ratio.[63] These design and operating variables are discussed below.

Several catalyst materials are available, and each has an optimum NO_x removal efficiency range corresponding to a specific temperature range. Proprietary formulations containing titanium dioxide, vanadium pentoxide, platinum, or zeolite are available to meet a wide spectrum of operating temperatures. The NO_x removal efficiencies for these catalysts are typically between 80 and 90 percent when new. The NO_x removal efficiency gradually decreases over the operating life of the catalyst due to deterioration from masking, poisoning, or sintering.[63] The rate of catalyst performance degradation depends upon operating conditions and is therefore site-specific.

The space velocity (volumetric flue gas flow divided by the catalyst volume) is an indicator of gas residence time in the catalyst unit. The lower the space velocity, the higher the residence time, and the higher the potential for increased NO_x reduction. Because the gas flow is a constant determined by the gas turbine, the space velocity depends upon the catalyst volume, or total active surface area. The distance across the opening between plates or cells in the catalyst, referred to as the pitch, affects the overall size of the catalyst body. The smaller the pitch, the greater the number of rows or cells that can be placed in a given volume. Therefore, for a given catalyst body size, the smaller the pitch, the larger the catalyst volume and the lower the space velocity. For natural gas applications the catalyst pitch is typically 2.5 millimeters (mm) (0.10 inch [in.]), increasing to 5 to 7 mm (0.20 to 0.28 in.) for coal-fuel applications.[64]

As discussed in Section 5.3.1, the NH_3/NO_x ratio can be varied to achieve the desired level of NO_x reduction. Increasing this ratio increases the level of NO_x reduction but may also result in higher ammonia slip levels.

5.3.4 Achievable NO_x Emission Reduction Efficiency Using SCR

Most SCR systems operating in the United States have a space velocity of about 30,000/hr, a NH_3/NO_x ratio of about 1.0, and ammonia slip levels of approximately 10 ppm. The resulting NO_x reduction efficiency is about 90 percent.[41] Reduction efficiency is the level of NO_x removed as a percentage of the level of NO_x entering the SCR unit. Only one gas turbine installation in the United States was identified using only SCR to reduce NO_x emissions. This installation has two natural gas-fired 8.5 MW gas turbines, each with its own HRSG in which is installed an SCR system. A summary of emission testing at this site lists NO_x emissions at the inlet to the SCR catalyst at 130 ppmv. Controlled NO_x emissions downstream of the catalyst were 18 ppmv, indicating a NO_x reduction efficiency of 86 percent. Maximum ammonia slip levels were listed at 35 ppmv.[68]

All other gas turbine installations identified as using SCR in the United States use this control method in combination with wet injection and/or low-NO_x combustors. The emission levels that can be achieved by this combination of controls are found in Section 5.4.

5.3.5 Disposal Considerations for SCR

The SCR catalyst material has a finite life, and disposal can pose a problem. The guaranteed catalyst life offered by catalyst suppliers ranges from 2 to 3 years.[64] In Japan, where SCR systems have been in operation since 1980, experience shows that many catalysts in operation with natural gas-fired boilers have performed well for 7 years or longer.[63,64] In any case, at some point the catalyst must be replaced, and those units containing heavy metal oxides such as vanadium or titanium potentially could be considered hazardous wastes. While the amount of hazardous material in the catalyst is relatively small, the volume of the catalyst body can be quite large, and disposal

of this waste could be costly. Some suppliers provide for the removal and disposal of spent catalyst. Precious metal and zeolite catalysts do not contain hazardous wastes.

5.4 CONTROLS USED IN COMBINATION WITH SCR

With but one exception, SCR units installed in the United States are used in combination with wet controls or combustion controls described in Sections 5.1 and 5.2. Wet controls yield NO_x emission levels of 25 to 42 ppmv for natural gas and 42 to 110 ppmv for distillate oil, based on the data provided by gas turbine manufacturers and shown in Figures 5-10 and 5-11. A carefully designed SCR system can achieve NO_x reduction efficiencies as high as 90 percent, with ammonia slip levels of 10 ppmv or less for natural gas and low-sulfur (<0.3 percent by weight) fuel applications.[64]

As discussed for wet injection in Sections 5.1.4 and 5.2.2.4, controlled NO_x emission levels for natural gas range from 25 to 42 ppmv for natural gas fuel and from 42 to 110 ppmv for oil fuel. Applying a 90 percent reduction efficiency for SCR, NO_x levels can be theoretically reduced to 2.5 to 4.2 and 4.2 to 11.0 ppmv for natural gas and oil fuels, respectively. For oil fuels and other sulfur-bearing fuels, a reduction efficiency of 90 percent requires special design considerations to address potential operational problems caused by the sulfur content in the fuel. This subject is discussed in Section 5.3.2. The final controlled NO_x emission level depends upon the NO_x level exiting the turbine and the achievable SCR reduction efficiency.

Test reports provided by SCAQMD include three gas turbine combined cycle installations fired with natural gas that have achieved NO_x emission levels of 3.4 to 7.2 ppmv, referenced to 15 percent oxygen. The NO_x and CO emissions reported for these tests are shown in Table 5-17

TABLE 5-17. EMISSIONS TESTS RESULTS FOR GAS TURBINES USING STEAM INJECTION PLUS SCR[69-71]

				NO_x emissions, ppmv (lb/hr)			
Test No.	Gas turbine model	Output, MW	Fuel	Uncontrolled	Wet injection	Wet injection + SCR	CO, ppmv
1	MS7001E	82.8	Natural gas + refinery gas mixture	154	42	5.66 (25.2)	<2.00
2	MS7001E	79.7	Natural gas + refinery gas + butane mixture	148	42	7.17 (31.7)	<2.00
3	MS6001B	33.8	LPG + refinery gas mixture	148	42	3.36 (5.82)	<2.00

TABLE 5-18. SUMMARY OF SCR NO_x EMISSION REDUCTIONS AND AMMONIA SLIP LEVELS FOR NATURAL GAS-FIRED TURBINES[68]

Site	Gas turbine		Power output, MW	SCR operating temperature, °F	Maximum permit level for injection, NH_3/NO_x molar ratio	NO_x emissions, ppmv at 15% O_2			Compliance test NH_3 slip, ppmv at 15% O_2 [a]
	Manufacturer	Model				SCR in	SCR out	Percent reduction	
A	GE	LM2500	22	730	1.0	50	9.0	82	10
B	GE	MS5001	18	645	1.0	45	4.5	90	2
C	GE	LM2500	22	685	1.1	37	8.9	76	20
D	ABB	Type 8	44	760	1.2	27	4	85	9
E	GE	LM2500	22	680	1.0	60	12.6	79	7
F	GE	MS7001E	80	630	1.0	28	8.4	70	4.1
G	GE	LM2500	22	625	0.9	68	13.6	80	1
H	Allison	501-KB	3.5	650	1.1	25	1.0	96	10
I	Solar	Mars	8.5	580	1.6	130	18.2	86	35
J	GE	LM2500	22	750	1.0	37	14.8	60	11
K	GE	MS7001E	80	754	1.0	40	6.0	85	2
L	GE	MS6001	37	650	1.0	47	8.9	81	4
M	GE	MS6001	37	700	NA	33	3.3	90	8

[a]Calculated from ppmv entering the SCR and percent reduction figures.
[b]NH_3 permit limit. Test emission level not available.
[c]Test was run at less than permit NH_3/NO_x ratio of 1.1. SCR designed for exhaust from total of 5 turbines. Only one turbine operating during test.
[d]This site does not use wet injection for gas turbine NO_x reduction.
[e]NH_3 compliance test not required. NH_3 level from NH_3 monitor testing.

Ammonia slip levels were not reported. Ammonia slip levels

were reported, however, in a summary of emission tests for 13 SCR installations and are presented in Table 5-18.[68] For these sites, operating on natural gas fuel, the NO_x reduction efficiency of the catalyst ranges

from 60 to 96 percent, with most reduction efficiencies between 80 and 90 percent. Ammonia slip levels range from 1 to 35 ppmv. The site with the 35 ppmv ammonia slip level is unique in that it is the only site identified in the United States that uses only SCR rather than a combination of SCR and wet injection to reduce NO_x emissions. With the exception of this site, all NH_3 slip levels in Table 5-18 that are based on test data are less than 10 ppmv. Based on information received from catalyst vendors, it is expected that an SCR system operating downstream of a gas turbine without wet injection could be designed to limit ammonia slip levels to 10 ppmv or less.[64] No test data are available for SCR operation on gas turbines fired with distillate oil fuels.

5.5 EFFECT OF ADDING A DUCT BURNER IN HRSG APPLICATIONS

A duct burner is often added in cogeneration and combined cycle applications to increase the steam capacity of the HRSG (see Section 4.2.2). Duct burners in gas turbine exhaust streams consist of pipes or small burners that are placed in the exhaust gas stream to allow firing of additional fuel, usually natural gas. Duct burners can raise gas turbine exhaust temperatures to 1000°C (2000°F), but a more common temperature is 760°C (1400°F). The gas turbine exhaust is the source of oxygen for the duct burner.

Figure 5-29 shows a typical natural gas-fired duct burner

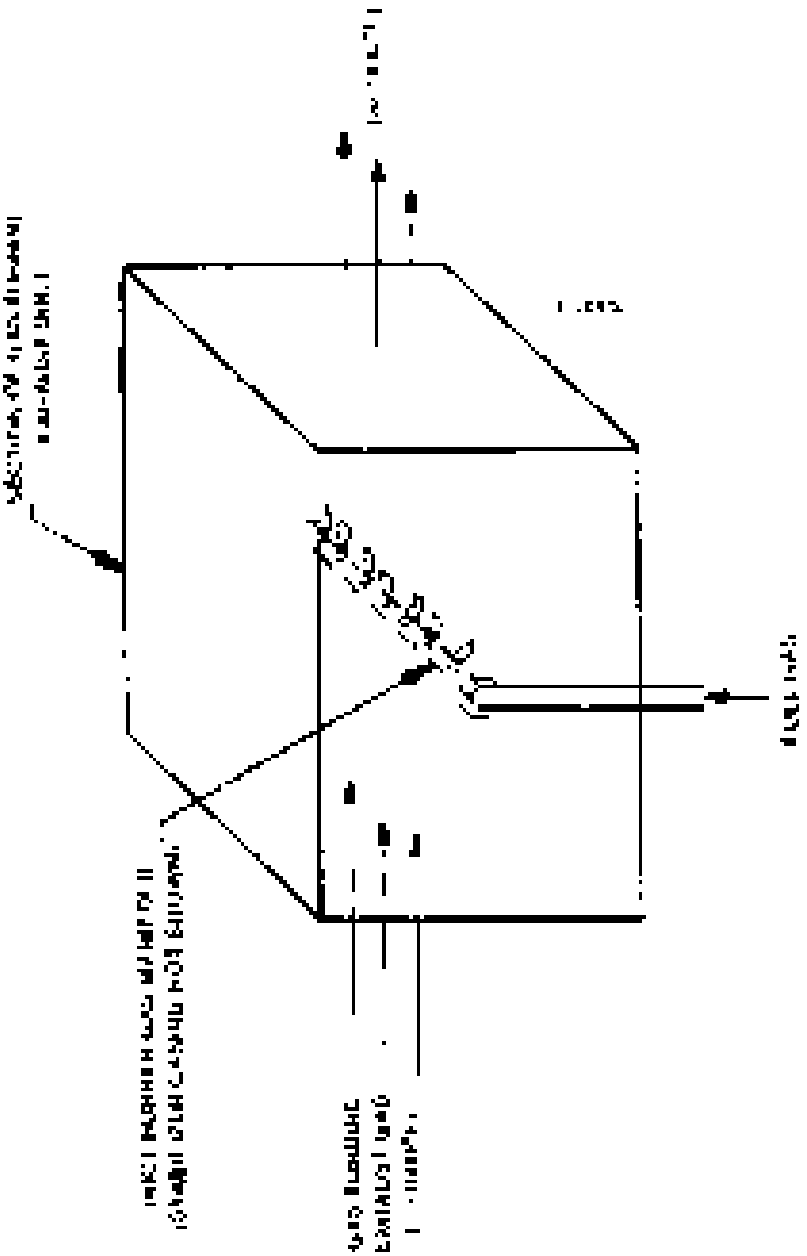


Figure 5-29. Typical duct burner for gas turbine exhaust application.[72]

installation. Figure 5-30 is a cross-sectional view of one style

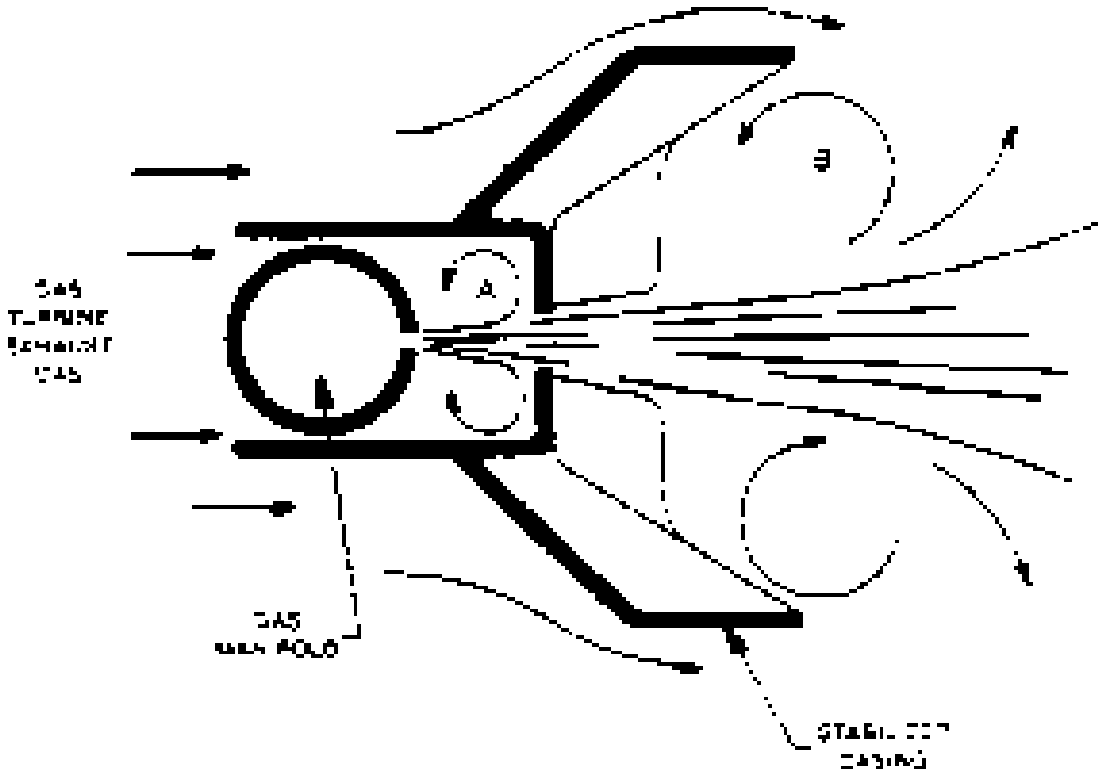


Figure 5-30. Cross-sectional view of a low-NO_x duct burner.[73,74]

of duct burner that incorporates design features to reduce NO_x. In this low-NO_x design, natural gas exits the orifice in the manifold and mixes with the gas turbine exhaust entering through a small slot between the casing and the gas manifold. This mixture forms a jet diffusion flame that causes the recirculation shown in Zone "A." Due to the limited amount of turbine exhaust that can enter Zone A, combustion in this zone is fuel-rich. As the burning gas jet exits into Zone "B," it mixes with combustion products that are recirculated by the flow eddies behind the wings of the stabilizer casing. The flame then expands into the turbine exhaust gas stream, where combustion is completed.

For oil-fired burners, the design principles of the burner are the same. However, the physical layout is slightly different, as shown in

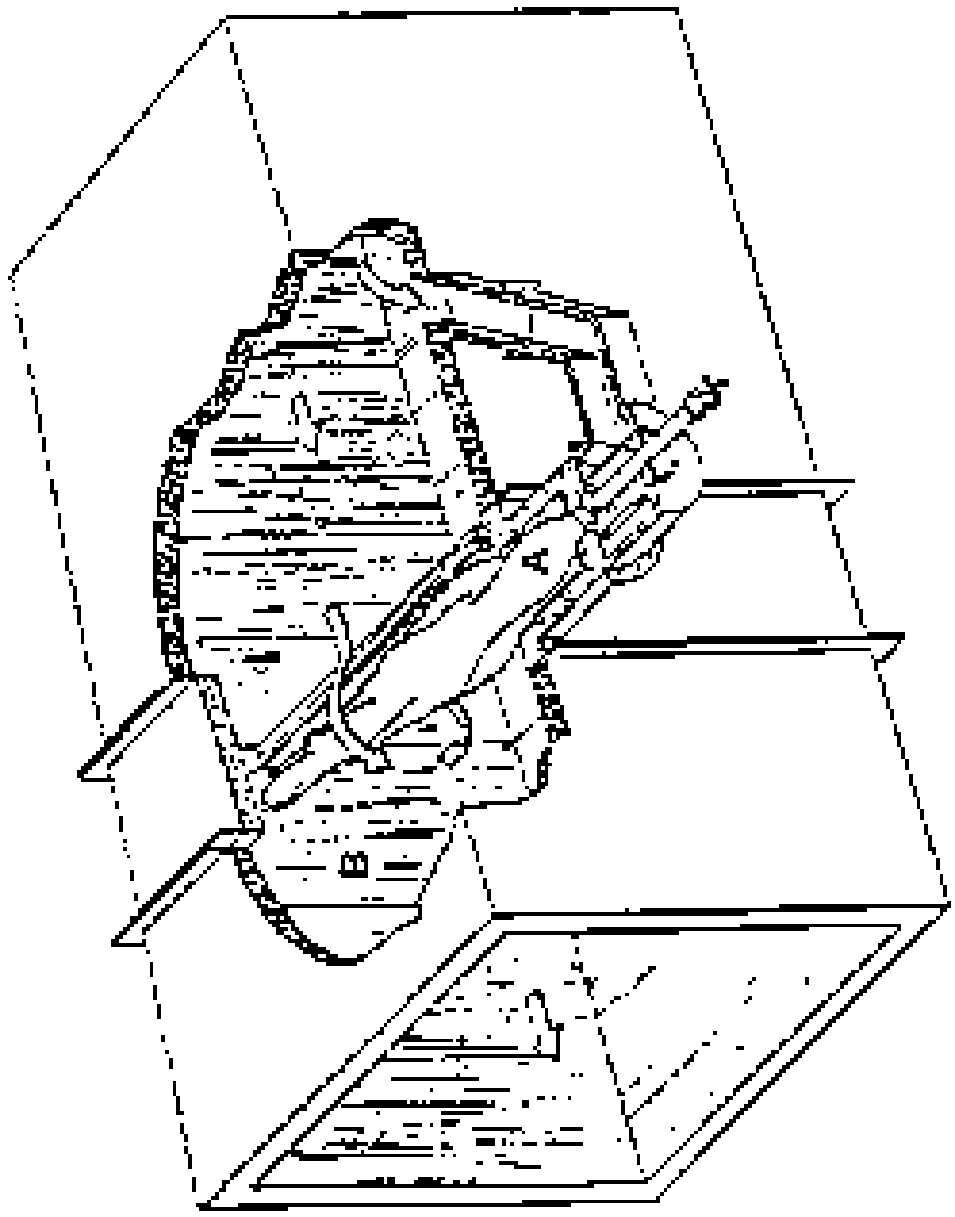


Figure 5-31. Low-NO_x duct burner designed for oil firing.[73,75]

Figure 5-31. Turbine exhaust gas is supplied in substoichiometric quantities by a slip stream duct to the burner. This slip stream supplies the combustion air for the fuel-rich Zone A. The flame shield produces the flow eddies, which recirculate the combustion products into Zone B.[76]

Most duct burners now in service fire natural gas. In all cases, a duct burner will produce a relatively small level of NO_x emissions during operation (See Section 4.2.2), but the net impact on total exhaust emissions (i.e., the gas turbine plus the duct burner) varies with operating conditions, and in some cases may even reduce the overall NO_x emissions. Table 5-19 shows the NO_x emissions measured at one site upstream and downstream of a duct burner. This table shows that NO_x emissions are reduced across the duct burner in five of the eight test runs.

TABLE 5-19. NO_x EMISSIONS MEASURED BEFORE AND AFTER A DUCT BURNER [77]

Gas turbine operation parameters			Duct burner operating parameters		Duct burner inlet		Duct burner outlet		Change across duct burner	
Test No.	Load, MW	Steam/fuel injection ratio, lb/lb	Heat input, MM Btu/hr	Load, percent	NO_x, lb/MM Btu	NO_x, lb/hr	NO_x, lb/MM Btu	NO_x, lb/hr	NO_x, lb/MM Btu	NO_x, lb/hr
1	33.8	0.94	133.8	82.1	0.149	61.4	0.097	55.7	-0.043	-5.7
2	35.0	0.97	93.3	57.3	0.142	58.8	0.113	58.9	0.001	0.1
3	34.5	0.95	40.8	25.0	0.134	57.5	0.118	58.7	0.029	1.2
4	32.0	0.50	137.5	84.4	0.207	85.8	0.151	83.9	-0.014	-1.9
5	32.8	0.46	43.8	26.8	0.228	95.2	0.192	94.0	-0.027	-1.2
6	31.5	0.00	136.7	83.9	0.392	159.7	0.270	156.2	-0.026	-3.5
7	33.0	0.00	42.0	25.8	0.384	166.7	0.313	156.7	-0.238	-10.0
8	11.1	0.00	140.9	86.5	0.157	29.1	0.132	42.1	0.092	13.0

The reason for this net NO_x reduction is not known, but it is believed to be a result of the reburning process in which the intermediate combustion products from the duct burner interact with the NO_x already present in the gas turbine exhaust. The manufacturer of the burner whose emission test results are shown in Table 5-19 states that the following conditions are necessary for reburning to occur:

1. The burner flame must produce a high temperature in a fuel-rich zone;

2. A portion of the turbine exhaust containing NO_x must be introduced into the localized fuel-rich zone with a residence time sufficient for the reburning process to convert the turbine NO_x to N_2 and O_2; and

3. The burner fuel should contain no FBN.[78]

In general, sites using a high degree of supplementary firing have the highest potential for a significant amount of reburning. In practice, only a limited number of sites achieve these reburning conditions due to specific plant operating requirements.[78]

5.6 ALTERNATE FUELS

Because thermal NO_x production is an exponential function of flame temperature (see Section 4.1.1), it follows that using fuels with flame temperatures lower than those of natural gas or distillate oils results in lower thermal NO_x emissions. Coal-derived gas and methanol have demonstrated lower NO_x emissions than more conventional natural gas or oil fuels. For applications using fuels with high FBN contents, switching to a fuel with a lower FBN content will reduce thermal NO_x formation and thereby lower total NO_x emissions.

5.6.1 Coal-Derived Gas

Combustor rig tests have demonstrated that burning coal-derived gas (coal gas) that has been treated to remove FBN produces approximately 30 percent of the NO_x emission levels experienced when burning natural gas. This is because coal gas has a low heat energy level of around 300 Btu or less, which results in a flame temperature lower than that of natural gas.[79] The cost associated with producing coal gas suitable for combustion in a gas turbine has made this alternative economically unattractive, but recent advances in coal gasification technology have renewed interest in this fuel.

A coal gas-fueled power plant is currently operating in the United States at a Dow Chemical plant in Placquemine, Louisiana. This facility operates with a subsidy from the Federal Government, which compensates for the price difference between coal gas and conventional fuels. Several commercial projects have been recently announced using technology developed by Texaco, Shell, Dow Chemical, and the U.S. Department of Energy. Facilities have been permitted for construction in Massachusetts and Delaware.[80]

A demonstration facility, known as Cool Water, operated using coal gas for 5 years in Southern California in the early 1980's. The NO_x emissions were reported at 0.07 lb/MMBtu.[80] Fuel analysis data is not available to convert this NO_x emission level to a ppmv figure. No other emissions data are available.

5.6.2 Methanol

Methanol has a flame temperature of 1925°C (3500°F) versus 2015°C (3660°F) for natural gas and greater than 2100°C (3800°F) for distillate oils. As a result, the NO_x emission levels when burning methanol are lower than those for either natural gas or distillate oils.

Table 5-20 presents NO_x emission data for a full-scale turbine firing methanol.

TABLE 5-20. NO_x EMISSIONS TEST DATA FOR A GAS TURBINE FIRING METHANOL AT BASELOAD[a,81]

Test	W/F ratio, lb/lb	NO_x emissions ISO conditions, ppm at 15% O_2	NO_x reduction, percent[b]
A	0	41	0
B	0	45	0
C	0	48	0
D	0	49	0
E	0	60	0
F	0	47	0
G	0	53	0
H	0	48	0
I	0	51	0
J	0	52	0
K	0	41	0
L	0	47	0
M	0	48	0
AVERAGE		49	
N	0.11	28	42.2
O	0.23	17	65.2
P	0.23	18	62.7
Q	0.24	18	62.7

[a]Baseload = 25 MW output
[b]Calculated using the average of the uncontrolled emissions.

The NO_x emissions from firing methanol without water injection ranged from 41 to 60 ppmv and averaged 49 ppmv. This test also indicated that methanol increases turbine output due to the higher mass flows that result from methanol firing. Methanol firing increased CO and HC emissions slightly compared to the same turbine's firing distillate oil with water injection. All other aspects of turbine performance were as good when firing methanol as when the turbine fired natural gas or distillate oil.[82] Turbine maintenance requirements were estimated to be lower and turbine life was estimated to be longer on methanol fuel than on distillate oil fuel because methanol produced fewer deposits in the combustor and power turbine.

Table 5-20 also presents NO_x emission data for methanol firing with water injection. At water-to-fuel ratios from 0.11 to 0.24, NO_x emissions when firing methanol range from 17 to 28 ppmv, a reduction of 42 to 65 percent.

In a study conducted at an existing 3.2 MW gas turbine installation in 1984, a gas turbine was modified to burn methanol. This study was conducted at the University of California at Davis and was sponsored by the California Energy Commission. A new fuel delivery system for methanol was required, but the only major modifications required for the turbine used in this study were new fuel manifolds and nozzles. Tests conducted burning methanol showed no visible smoke emissions, and only minor increases in CO emissions. Figure 5-32 shows the NO_x emissions measured while burning

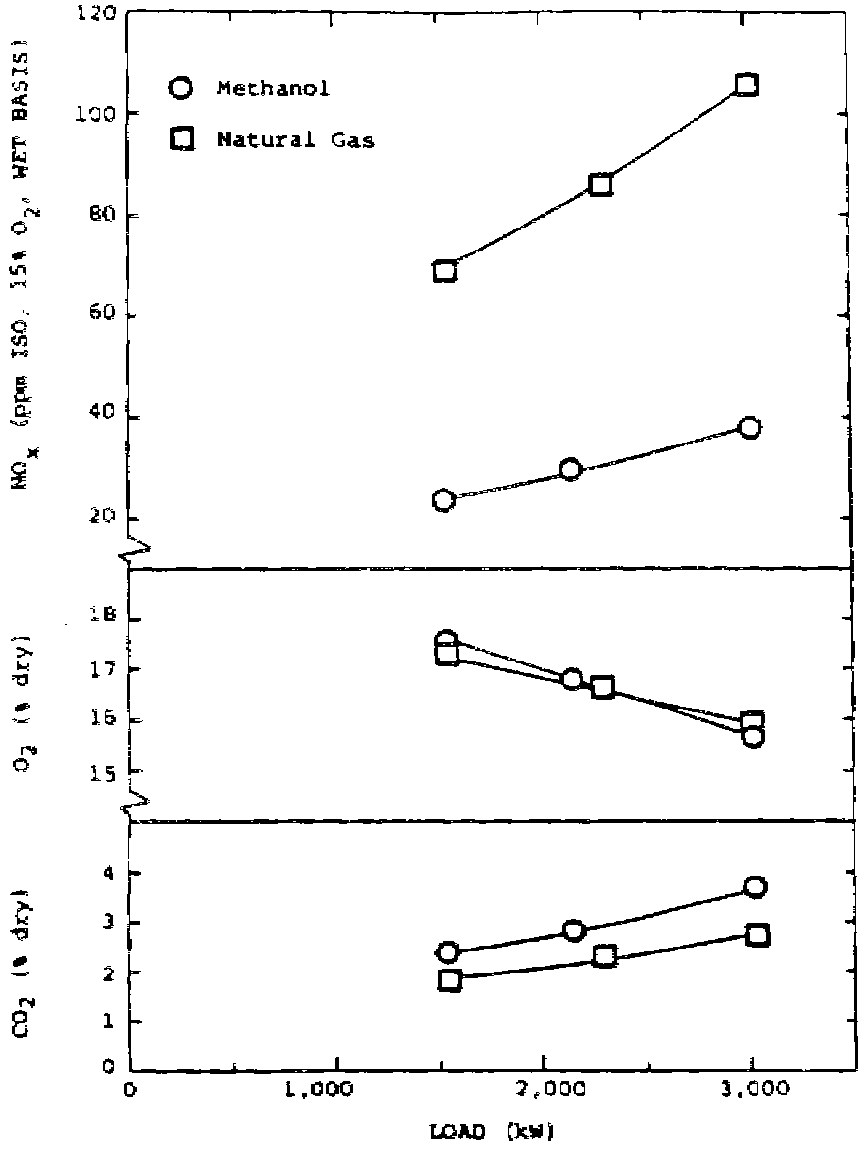


Figure 5-32. Influence of load on NO_x, and CO_2 emissions for methanol and natural gas.[83]

methanol and natural gas. Reductions of up to 65 percent were achieved, as NO_x emissions were 22 to 38 ppm when burning methanol versus

62 to 100 ppm for natural gas. In addition to the intrinsically lower NO_x production, water can be readily mixed with methanol prior to delivery to the turbine to obtain the additional NO_x reduction levels achievable with wet injection. Gas turbine performance characteristics, including startup, acceleration, load changes, and full load power, were all deemed acceptable by the turbine manufacturer.[83]

The current economics of using methanol as a primary fuel are not attractive. There are no confirmed commercial methanol-fueled gas turbine installations in the United States.

5.7 SELECTIVE NONCATALYTIC REDUCTION

Selective noncatalytic reduction (SNCR) is an add-on technology that reduces NO_x using ammonia or urea injection similar to SCR but operates at a higher temperature. At this higher operating temperature of 870° to 1200°C (1600° to 2200°F), the following reaction occurs:[84]

$$NO_x + NH_3 + O_2 + H_2O + (H_2) \rightarrow N_2 + H_2O.$$

This reaction occurs without requiring a catalyst, effectively reducing NO_x to nitrogen and water. The operating temperature can be lowered from 870°C (1600°F) to 700°C (1300°F) by injecting hydrogen (H_2) with the ammonia, as is shown in the above equation.

Above the upper temperature limit, the following reaction occurs:[84]

$$NH_3 + O_2 \rightarrow NO_x + H_2O.$$

Levels of NO_x emissions increase when injecting ammonia or urea into the flue gas at temperatures above the upper temperature limits of 1200°C (2200°F).

Since SNCR does not require a catalyst, this process is more attractive than SCR from an economic standpoint. The operating temperature window, however, is not compatible with gas turbine exhaust temperatures, which do not exceed 600°C (1100°F). Additionally, the residence time required for the reaction is approximately 100 milliseconds, which is relatively slow for gas turbine operating flow velocities.[85]

It may be feasible, however, to initiate this reaction in the gas turbine where operating temperatures fall within the reaction window, if suitable gas turbine modifications and injection systems can be developed.[85] This control technology has not been applied to gas turbines to date.

5.8 CATALYTIC COMBUSTION

5.8.1 Process Description

In a catalytic combustor, fuel and air are premixed into a fuel-lean mixture (fuel/air ratio of approximately 0.02) and then pass into a catalyst bed. In the bed, the mixture oxidizes without forming a high-temperature flame front. Peak combustion temperatures can be limited to below 1540°C (2800°F), which is below the temperature at which significant amounts of thermal NO_x begin to form.[86] An example of a lean catalytic combustor is shown in Figure 5-33.

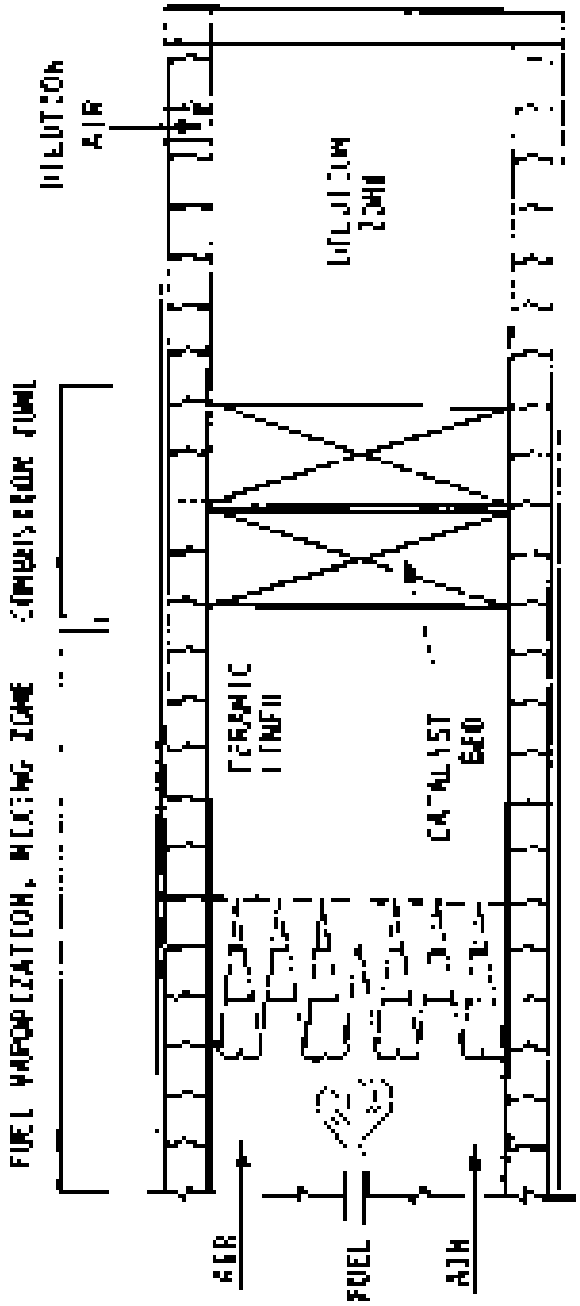


Figure 5-33. A lean catalytic combustor.87

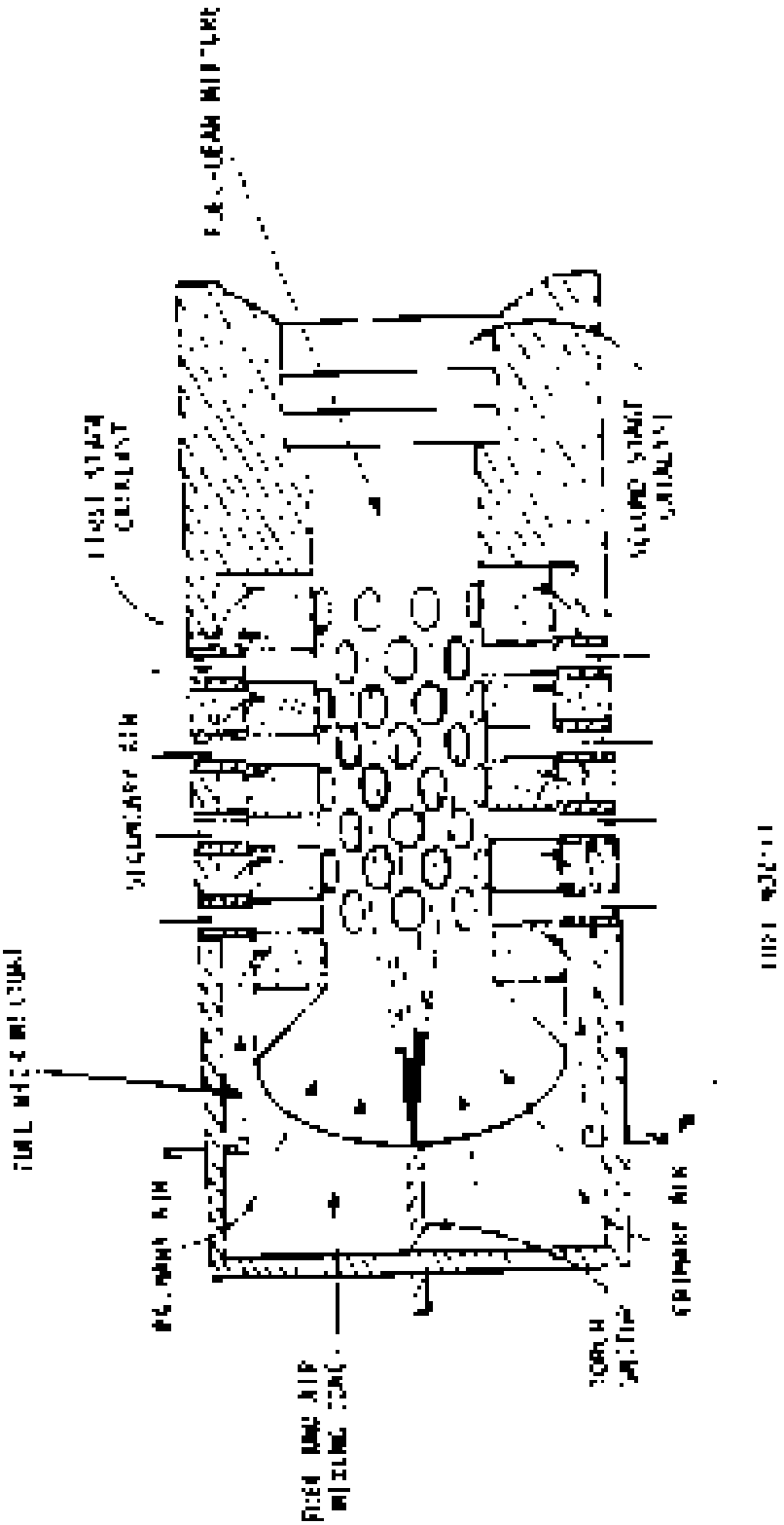


Figure 5-34. A rich/lean catalytic combustor.[89]

Catalytic combustors can also be designed to operate in a rich/lean configuration, as shown in Figure 5-34. In this configuration, the air and fuel are premixed to form a fuel-rich mixture, which passes through a first stage catalyst where combustion begins. Secondary air is then added to produce a lean mixture, and combustion is completed in a second stage catalyst bed.[89]

5.8.2 Applicability

Catalytic combustion techniques apply to all combustor types and are effective on both distillate oil- and natural gas-fired turbines. Because of the limited operating temperature range, catalytic combustors may not be easily applied to gas turbines subject to rapid load changes (such as utility peaking turbines).[90] Gas turbines that operate continuously at base load (such as industrial cogeneration applications) would not be as adversely affected by any limits on load following capability.[91]

5.8.3 Development Status

Presently, the development of catalytic combustors has been limited to bench-scale tests of prototype combustors. The major problem is the development of a catalyst that will have an acceptable life in the high-temperature and -pressure environment

of gas turbine combustors. Additional problems that must be solved are combustor ignition and how to design the catalyst to operate over the full gas turbine operating range (idle to full load).[92]

5.9 OFFSHORE OIL PLATFORM APPLICATIONS

Gas turbines are used on offshore platforms to meet compression and electrical power requirements. This application presents unique challenges for NO_x emissions control due to the duty cycle, lack of a potable water source for wet injection, and limited space and weight considerations. The duty cycle for electric power applications of offshore platforms is unique. This duty cycle is subject to frequent load changes that can instantaneously increase or decrease by as much as a factor of 10.[93] Fluctuating loads result in substantial swings in turbine exhaust gas temperatures and flow rates. This presents a problem for SCR applications because the NO_x reduction efficiency depends upon temperature and space velocity (see Section 5.3.3).

The lack of a potable water supply means that water must be shipped to the platform or sea water must be desalinated and treated. The limited space and weight requirements associated with an SCR system may also have an impact on capital costs of the platform.

A 4-year study is underway for the Santa Barbara County Air Pollution Control Board to evaluate suitable NO_x control techniques for offshore applications. The goals of the study are to reduce turbine NO_x emissions at full load to 9 ppmv, corrected to 15 percent O_2, firing platform gas fuel and to achieve part load reductions of 50 percent. The study consists of two phases. The first phase, an engineering evaluation of available and emerging emission control technologies, is completed. The second phase will select the final control technologies and develop these technologies for offshore platform applications. Phase I

of this study concludes that the technologies with the highest estimated probability for success in offshore applications are:

- Water injection plus SCR (80 percent);
- Methanol fuel plus SCR (70 percent);
- Lean premixed combustion plus SCR (65 percent); and
- Steam dilution of fuel prior to combustion plus SCR (65 percent).

A key conclusion drawn from Phase I of this study is that none of the above technologies or combination of technologies in offshore platform applications currently has a high probability of successfully achieving the NO_x emission reduction goals of this study without substantial cost and impacts to platform and turbine operations, added safety considerations, and other environmental concerns. These issues will be further studied in Phase II for the above control technologies.

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6.0 CONTROL COSTS

Capital and annual costs are presented in this chapter for the nitrogen oxide (NO_x) control techniques described in Chapter 5.0. These control techniques are water and steam injection, low-NO_x combustion, and selective catalytic reduction (SCR) used in combination with these controls. Model plants were developed to evaluate the control techniques for a range of gas turbine sizes, fuel types, and annual operating hours. The gas turbines chosen for these model plants range in size from 1.1 to 160 megawatts (MW) (1,500 to 215,000 horsepower [hp]) and include both aeroderivative and heavy-duty turbines. Model plants were developed for both natural gas and distillate oil fuels. For offshore oil production platforms, cost information was available only for one turbine model.

The life of the control equipment depends upon many factors, including application, operating environment, maintenance practices, and materials of construction. For this study, a 15-year life was chosen.

Both new and retrofit costs are presented in this chapter. For water and steam injection, these costs were assumed to be the same because most of the water treatment system installation can be completed while the plant is operating and because gas turbine nozzle replacement and piping connections to the treated water supply can be performed during a scheduled downtime for maintenance. Estimated costs are provided for both new and retrofit low-NO_x combustion applications. No SCR retrofit applications were identified, and costs for SCR retrofit applications were not available. The cost to retrofit an

existing gas turbine installation with SCR would be considerably higher than the costs shown for a new installation, especially for combined cycle and cogeneration installations where the heat-recovery steam generator (HRSG) would have to be modified or replaced to accommodate the catalyst reactor.

This chapter is organized into five sections. Water and steam injection costs are described in Section 6.1. Low-NO_x combustor costs are summarized in Section 6.2. Costs for SCR used in combination with water or steam injection or low-NO_x combustion are described in Section 6.3. Water injection and SCR costs for offshore gas turbines are presented in Section 6.4, and references are listed in Section 6.5.

a. WATER AND STEAM INJECTION AND OIL-IN-WATER EMULSION

Ten gas turbines models were selected, and from these turbines 24 model plants were developed using water or steam injection or water-in-oil emulsion to control NO_x emissions. These 24 models, shown in Table 6-1

TABLE 6-1. GAS TURBINE MODEL PLANTS FOR NO_x CONTROL TECHNIQUES

Model plant[a]	GT model	Turbine output, MW	Annual operating hours	Fuel, natural gas or oil	Type of emission control	Aeroderivative (AD) or heavy-duty (HD) turbine
CON-G-W-3.3	Centaur T4500	3.3	8,000	Gas	Water	HD
CON-G-W-4.0	501-KB5	4.0	8,000	Gas	Water	AD
CON-G-W-22.7	LM2500	22.7	8,000	Gas	Water	AD
CON-G-W-26.8	MS5001P	26.8	8,000	Gas	Water	HD
CON-G-W-83.3	ABB GT11N	83.3	8,000	Gas	Water	HD
CON-G-W-84.7	MS7001E	84.7	8,000	Gas	Water	HD
CON-G-S-4.0	501-KB5	4.0	8,000	Gas	Steam	AD
CON-G-S-22.7	LM2500	22.7	8,000	Gas	Steam	AD
CON-G-S-26.8	MS5001P	26.8	8,000	Gas	Steam	HD
CON-G-S-34.4	LM5000	34.5	8,000	Gas	Steam	AD
CON-G-S-83.3	ABB GT11N	83.3	8,000	Gas	Steam	HD
CON-G-S-84.7	MS7001E	84.7	8,000	Gas	Steam	HD
CON-G-S-161	MS7001F	161	8,000	Gas	Steam	HD
CON-O-W-3.3	Centaur T4500	3.3	8,000	Oil	Water	HD
CON-O-W-26.3	MS5001P	26.3	8,000	Oil	Water	HD
CON-O-W-83.3	MS7001E	83.3	8,000	Oil	Water	HD
PKR-G-W-3.3	Centaur T4500	3.3	2,000	Gas	Water	HD
PKR-G-W-26.8	MS5001P	26.8	2,000	Gas	Water	HD
PKR-G-W-84.7	MS7001E	84.7	2,000	Gas	Water	HD
PKR-O-W-3.3	Centaur T4500	3.3	2,000	Oil	Water	HD
PKR-O-W-26.3	MS5001P	26.3	2,000	Oil	Water	HD
PKR-O-W-84.7	MS7001E	84.7	2,000	Oil	Water	HD
STD-O-W-1.1	Saturn T1500	1.0	1,000	Oil	Water	HD
STD-O-E-28.0	TPM FT4	28.0	1,000	Oil	Water-in-oil emulsion	AD

[a]Model plant legend:

First entry: annual operating hours
CON--continuous duty, 8,000 hours
PKR--peaking duty, 2,000 hours
STD--stand-by duty, 1,000 hours

Second entry: fuel type
G = natural gas fuel
O = oil fuel

Third entry: control type
W = water injection
S = steam injection
E = water-in-oil emulsion

Fourth entry: power output in MW

For example, CON-G-W-3.3 designates that the model plant is continuous-duty, uses natural gas fuel, has water injection, and has a power output of 3.3 MW.

, characterize variations in existing units with respect to turbine size, type (i.e., aero-derivative vs. heavy duty), operating hours, and type of fuel. A total of 24 model plants were developed; 16 of these were continuous-duty (8,000 hours per year) and 8 were intermittent-duty (2,000 or 1,000 hours per year). Thirteen of the continuous-duty model plants burn natural gas fuel; 6 of the 13 use water injection, and 7 use steam injection to reduce NO_x emissions. The three remaining continuous-duty model plants burn distillate oil fuel and use water injection to reduce NO_x emissions. Of the eight intermittent-duty model plants, six operate 2,000 hours per year (three natural gas-fueled and three distillate oil-fueled), and two operate 1,000 hours per year (both distillate oil-fueled). All intermittent-duty model plants use water rather than steam for NO_x reduction because it was assumed that the additional capital costs associated with steam-generating equipment could not be justified for intermittent service.

Costs were available for applying water-in-oil emulsion technology to only one gas turbine, and insufficient data were available to develop costs for a similar water-injected model

plant for this turbine. As a result, the costs and cost effectiveness for the water-in-oil emulsion model plant should not be compared to those of water-injected model plants.

Capital costs are described in Section 6.1.1, annual costs are described in Section 6.1.2, and emission reductions and the cost effectiveness of wet injection controls are discussed in Section 6.1.3. Additional discussion of the cost methodology and details about some of the cost estimating procedures are provided in Appendix B.

Fuel rates and water flow rates were calculated for each model plant using published design power output and efficiency, expressed as heat rate, in British thermal units per kilowatt-hour (Btu/kWh).[1] The values for these parameters are presented in Table 6-2

TABLE 6-2. FUEL AND WATER FLOW RATES FOR WATER AND STEAM INJECTION (1990 $)

Model plant	GT model	Turbine output, kW	Heat rate (HR), Btu/kW-hr	Fuel flow		Estimated WFR, lb water/lb fuel	Water flow, gal/min[c]	Treatment system capacity, gal/min[d]
				lb/hr[a]	MMBtu/yr[b]			
CON-G-W-3.3	Centaur T4500	3,270	12,900	2,050	337,000	0.61	2.50	4.20
CON-G-W-4.0	501-KB5	4,000	12,700	2,460	406,000	0.80	3.94	6.60
CON-G-W-22.7	LM2500	22,670	9,220	10,100	1,670,000	0.73	14.8	24.7
CON-G-W-26.8	MS5001P	26,800	11,870	15,400	2,540,000	0.72	22.2	37.2
CON-G-W-83.3	ABB GT11N	83,300	10,400	42,000	6,930,000	1.83	154	258
CON-G-W-84.7	MS7001E	84,700	10,400	42,700	7,050,000	0.81	69.2	116
CON-G-S-4.0	501-KB5	4,000	12,700	2,460	406,000	1.50	7.38	12.4
CON-G-S-22.7	LM2500	22,670	9,220	10,100	1,670,000	1.46	29.5	49.5
CON-G-S-26.8	MS5001P	26,800	11,870	15,400	2,540,000	1.08	33.3	55.8
CON-G-S-34.4	LM5000	34,450	9,080	15,200	2,500,000	1.67	50.8	85.2
CON-G-S-83.3	ABB GT11N	83,300	10,400	42,000	6,930,000	2.12	178	299
CON-G-S-84.7	MS7001E	84,700	10,400	42,700	7,050,000	1.22	104	175
CON-G-S-161	MS7001F	161,000	9,500	74,200	12,240,000	1.34	199	334
CON-O-W-3.3	Centaur T4500	3,270	12,900	2,300	337,000	0.60	2.76	4.63
CON-O-W-26.3	MS5001P	26,300	11,950	17,100	2,510,000	0.79	27.0	45.3
CON-O-W-83.3	MS7001E	83,300	10,470	47,600	6,980,000	0.67	63.8	107
PKR-G-W-3.3	Centaur T4500	3,270	12,900	2,050	84,400	0.61	2.50	4.20
PKR-G-W-26.8	MS5001P	26,800	11,870	15,400	640,000	0.72	22.2	37.2
PKR-G-W-84.7	MS7001E	84,700	10,400	42,700	1,760,000	0.81	69.2	116
PKR-O-W-3.3	Centaur T4500	3,270	12,900	2,300	84,000	0.60	2.76	4.63
PKR-O-W-26.3	MS5001P	26,300	11,950	17,100	630,000	0.79	27.0	45.3
PKR-O-W-84.7	MS7001E	83,300	10,470	47,600	1,740,000	0.67	63.8	107
STD-O-W-1.1	Saturn T1500	1,130	14,200	875	16,000	0.46	0.81	1.35
STD-O-F-28.0	TPM FT4	28,000	14,500	19,700	406,000	0.55	21.7	36.4

[a]Natural gas: lb/hr = HR x kW x (lb/20,610 Btu). Diesel oil: lb/hr = HR x kW x (lb/18,330 Btu).

[b]MMBtu/yr = HR x kW x (MM/10^6) x (operating hours/year).

[c]Water (or steam) flow, gal/min = Fuel flow (lb/hr) x (1 hr/60 min) x (1 gal/8.33, lb. H_2O) x WFR.

[d]A 30 percent design factor has been included per discussion with system supplier, and the waste stream from the water treatment system is calculated to be 29 percent. The design capacity is therefore Water Flow x 1.3 x 1.29.

for each model plant. Fuel rates were estimated based on the heat rates, the design output, and the lower heating value (LHV) of the fuel. The LHV's used in this analysis for natural gas and diesel fuel are 20,610 Btu per pound (Btu/lb) and 18,330 Btu/lb, respectively, as shown in Table 6-3

TABLE 6-3. FUEL PROPERTIES AND UTILITY AND LABOR RATES[a]

Fuel properties	Factor	Units	Reference
Natural gas	20,610	Btu/lb	Ref. 3
	930	Btu/scf[c] (LHV)	Ref. 3
Diesel fuel	18,330	Btu/lb (LHV)	Ref. 2
	7.21	lb/gal	Ref. 2
Utility rates			
Natural gas[b]	3.88	$/scf	Ref. 4
Diesel fuel	0.77	$/gal	Ref. 5
Electricity	0.06	$/kW-hr	Ref.'s 6 and 7
Raw water	0.384	$/1,000 gal	Ref. 2, escalated @ 5% per year
Water treatment	1.97	$/1,000 gal	Ref. 2, escalated @ 5% per year
Waste disposal	3.82	$/1,000 gal	Ref. 2, escalated @ 5% per year
Labor rate			
Operating	25.60	$/hr	Ref. 2, escalated @ 5% per year
Maintenance	31.20	$/hr	Ref. 2, escalated @ 5% per year

[a]All costs are average costs in 1990 dollars.
[b]Natural gas and electricity costs from Reference 4 are the average of the costs for industrial and commercial customers.
[c]scf = standard cubic foot.

.[2] Water (or steam) injection rates were calculated based on published fuel rates and water-to-fuel ratios (WFR) provided by manufacturers.[8-12] According to a water treatment system supplier, treatment facilities are designed with a capacity factor of 1.3.[13] An additional 29 percent of the treated water flow rate is discarded as wastewater.[2] Consequently, the water treatment facility design capacity is 68 percent (1.30 x 1.29) greater than the water (or steam) injection rate.

i. Capital Costs

The capital costs for each model plant are presented in Table 6-4

TABLE 6-4. CAPITAL COSTS FOR WET INJECTION IN THOUSAND OF DOLLARS [a]

Model plant	GT model	Injection system (IS)[b]	Water treatment system (WTS)[c]	Total system (TS) = (IS + WTS)	Taxes and freight (TF) = (8% of TS)	Direct install. costs (DC) = (45% [TS + TF])	Indirect install. costs (IC)=(33% of [TS + TF +DC] + 5,000)	Contingency (C) = (20% of [TS + TF + DC + IC])	Total capital cost (TCC) = [TS + TF + DC + IC + C]
CON-G-W-3.3	Centaur T4500	113	89.9	203	16.2	50.0[d]	53.8[e]	64.6	388
CON-G-W-4.0	501-KB5	115	113	228	18.2	50.0[d]	59.2[e]	71.0	426
CON-G-W-22.7	LM2500	212	218	430	34.4	209	227	180	1,080
CON-G-W-26.8	MS5001P	215	268	483	38.6	235	254	202	1,210
CON-G-W-83.3	ABB GT11N	874	705	1,580	126	768	822	659	3,950
CON-G-W-84.7	MS7001E	562	473	1,030	82.4	501	537	430	2,580
CON-G-S-4.0	501-KB5	154	154	308	24.7	50.0	76.6	92.0	552
CON-G-S-22.7	LM2500	278	309	587	46.9	285	308	245	1,470
CON-G-S-26.8	MS5001P	262	328	590	47.2	287	310	247	1,480
CON-G-S-34.4	LM5000	530	405	935	74.8	454	488	391	2,340
CON-G-S-83.3	ABB GT11N	1,090	759	1,850	148	899	961	772	4,630
CON-G-S-84.7	MS7001E	715	580	1,300	104	632	677	543	3,260
CON-G-S-161	MS7001F	1,130	802	1,930	154	938	1,000	804	4,830
CON-O-W-3.3	Centaur T4500	114	94.5	208	16.7	50.0[d]	55.0[e]	66.0	396
CON-O-W-26.3	MS5001P	231	296	527	42.1	256	277	220	1,320
CON-O-W-83.3	MS7001E	532	454	986	78.9	479	515	412	2,470
PKR-G-W-3.3	Centaur T4500	113	89.9	203	16.2	50.0[d]	53.8[e]	64.6	388
PKR-G-W-26.8	MS5001P	215	268	483	38.6	235	254	202	1,210
PKR-G-W-84.7	MS7001E	562	473	1,030	82.4	501	537	430	2,580
PKR-O-W-3.3	Centaur T4500	114	94.5	208	16.7	50.0[d]	55.0[e]	66.0	396
PKR-O-W-26.3	MS5001P	231	296	527	42.1	256	277	220	1,320
PKR-O-W-84.7	MS7001E	532	454	986	78.9	479	515	412	2,470
STD-O-W-1.1	Saturn T1500	71.9	51.0	123	9.83	50.0	36.6	43.9	263
STD-O-F-28.0	TPM FT4	128	NA[f]	128	10.2	62.2	71.1	54.3	326

[a]All costs in 1990 dollars.

[b]Injection nozzle costs provided by manufacturers. Balance of water injection system calculated at a cost of $4,200 x GPM.

[c]WTS = 43,900 x (design capacity, gal/min) $^{0.5}$

[d]Direct installation cost is estimated at $50,000 for model plants rated at 5 MW or less.

[e]Indirect installation cost factor of 33 percent is reduced to 20 percent for model plants rated at 5 MW or less.

[f]NA = cost calculations based on using a portable demineralizer systems during turbine operating periods. Cost for system usage is included in Table 6-5.

. These costs were developed based on methodology in Reference 2, which is presented in this section. The capital costs include purchased equipment costs, direct and indirect installation costs, and contingency costs.

(1) Purchased Equipment Costs. Purchased equipment costs consist of the injection system, the water treatment system, taxes, and freight. All costs are presented in 1990 dollars.

(a) Water injection system. The injection system delivers water from the treatment system to the combustor. This system includes the turbine-mounted injection nozzles, the flow metering controls, pumps, and hardware and interconnecting piping from the treatment system to the turbine. On-engine hardware (the injection nozzles) costs were provided by turbine manufacturers.[9,14-17] Flow metering controls and hardware, pumps, and interconnecting piping costs for all turbines were calculated using data provided by General Electric for four heavy-duty turbine models.[17] No relationship between costs and either turbine output or water flow was evident, so the sum of the four costs was divided by the sum of the water flow requirements for the four turbines. This process yielded a cost of $4,200 per gallon per minute (gal/min), and this cost, added to the on-engine hardware costs, was used for all model plants.

(b) Water treatment system. The water treatment process, and hence the treatment system components, varies according to the degree to which the water at a given site must be treated. For this cost analysis, the water treatment system includes a reverse osmosis and mixed-bed demineralizer system. The water treatment system capital cost for each model plant was estimated based on an equation developed in Reference 2:

$$WTS = 43{,}900 \times (G)^{0.50}$$

where

WTS = water treatment system capital cost, $; and

G = water treatment system design capacity, gal/min.

This equation yields costs that are generally consistent with the range of costs presented in Reference 18.

(c) Taxes and freight. This cost covers applicable sales taxes and shipment to the site for the injection and water treatment systems. A figure of 8 percent of the total system cost was used.[2,7]

(2) Direct Installation Costs. This cost includes the labor and material costs associated with installing the foundation and supports, erecting and handling equipment, electrical work, piping, insulation, and painting. For smaller

turbines, the water treatment system is typically skid-mounted and is shipped to the site as a packaged unit, which minimizes field assembly and interconnections. The cost to install a skid-mounted water treatment skid is typically $50,000, and this cost is used for the direct installation cost for model plants less than 5 MW (6700 hp).[19] For larger turbines, it is expected that the water treatment system must be field-assembled and the direct installation costs were calculated as 45 percent of the injection and water treatment systems, including taxes and freight.[2]

(3) Indirect Installation Costs. This cost covers the indirect costs (engineering, supervisory personnel, office personnel, temporary offices, etc.) associated with installing the equipment. The cost was taken to be 33 percent of the systems' costs, taxes and freight, and direct costs, plus $5,000 for model plants above 5 MW (6,700 hp).[2] The indirect installation costs for skid-mounted water treatment systems are expected to be less than for field-assembled systems; therefore, for model plants with an output of less than 5 MW (6,700 hp), the cost percentage factor was reduced from 33 to 20 percent.

(4) Contingency Cost. This cost is a catch-all meant to cover unforeseen costs such as equipment redesign/ modification, cost escalations, and delays encountered in startup. This cost was estimated as 20 percent of the sum of the systems, taxes and freight, and direct and indirect costs.[2]

ii. Annual Costs

The annual costs are summarized in Table 6-5

TABLE 6-5. ANNUAL COSTS FOR WATER AND STEAM INJECTION (1990 $)

Model plant	GT model	Fuel penalty (FP)[a]	Electricity (E)[b]	Added maintenance cost (M)[c]	Water treatment (WT)[d]					Plant overhead (PO) = (30% of M)	G&A taxes, insurance (GATI)[i]	Capital recovery (CR)[j]	Total annual cost (TAC)[k]
					Raw water[e]	Treat-ment[f]	Labor[g]	Disposal[h]	Total cost (TW)				
CON-G-W-3.3	Centaur T4500	30,000	193	16,000	595	3,050	1,080	1,330	6,050	4,800	15,500	51,000	124,000
CON-G-W-4.0	501-KB5	47,400	304	24,000	936	4,800	1,710	2,090	9,540	7,200	17,100	56,100	162,000
CON-G-W-22.7	LM2500	178,000	1,140	28,000	3,510	18,000	6,390	7,840	35,700	8,400	43,200	142,000	436,000
CON-G-W-26.8	MS5001P	267,000	1,714	33,000	5,270	27,100	9,620	11,800	53,800	9,900	48,400	159,000	573,000
CON-G-W-83.3	ABB GT11N	1,852,000	11,884	0	36,600	188,000	66,700	81,800	373,000	0	158,000	519,000	2,910,000
CON-G-W-84.7	MS7001E	834,000	5,348	25,700	16,500	84,400	30,000	36,800	168,000	7,710	103,000	339,000	1,480,000
CON-G-S-4.0	501-KB5	25,400	571	24,000	1,760	9,010	1,600	3,930	16,300	7,200	22,100	72,600	168,000
CON-G-S-22.7	LM2500	102,000	2,280	0	7,020	36,000	6,390	15,700	65,100	0	58,800	193,000	421,000
CON-G-S-26.8	MS5001P	114,000	2,572	33,000	7,910	40,600	7,210	17,700	73,400	9,900	59,200	195,000	487,000
CON-G-S-34.4	LM5000	174,000	3,925	0	12,100	62,000	11,000	27,000	112,000	0	93,600	308,000	692,000
CON-G-S-83.3	ABB GT11N	613,000	13,768	0	42,400	217,000	38,600	94,700	393,000	0	185,000	609,000	1,810,000
CON-G-S-84.7	MS7001E	359,000	8,055	0	24,800	127,000	22,600	55,400	230,000	0	130,000	429,000	1,160,000
CON-G-S-161	MS7001F	684,000	15,374	0	47,300	243,000	43,100	106,000	439,000	0	193,000	635,000	1,970,000
CON-O-W-3.3	Centaur T4500	41,200	213	20,800	657	3,370	1,200	1,470	6,700	6,240	15,800	52,100	143,000
CON-O-W-26.3	MS5001P	404,000	2,089	42,900	6,430	33,000	11,700	14,400	65,500	12,900	52,800	174,000	754,00
CON-O-W-83.3	MS7001E	954,000	4,931	33,400	15,200	77,800	27,700	33,900	155,000	10,020	98,800	325,000	1,580,000
PKR-G-W-3.3	Centaur T4500	7,500	48.3	4,000	149	760	270	330	1,510	1,200	15,500	51,000	80,800
PKR-G-W-26.8	MS5001P	67,000	429	8,250	1,320	6,770	2,400	2,950	13,400	2,500	48,400	159,000	299,000
PKR-G-W-84.7	MS7001E	208,000	1,337	6,430	4,110	21,100	7,500	9,200	41,900	1,929	103,000	339,000	702,000
PKR-O-W-3.3	Centaur T4500	10,300	53.3	5,200	164	840	300	370	1,670	1,560	15,800	52,100	86,700
PKR-O-W-26.3	MS5001P	101,000	522	10,725	1,610	8,240	2,930	3,590	16,400	3,200	52,800	174,000	359,000
PKR-O-W-84.7	MS7001E	238,000	1,233	8,350	3,790	19,500	6,910	8,480	38,700	2,505	99,000	325,000	713,000
STD-O-W-1.1	Saturn T1500	1,500	7.78	1,300	23.9	123	43.7	53.6	244	390	10,530	34,600	48,600
STD-O-E-28.0	TPM FT4	45,500	209	0	644	51,100	1,170	1,440	54,400	0	13,000	42,900	156,000

[a]FP for water = 0.035 x WFR x (MMBtu/yr) x (ft ^{3}/940 Btu) x ($3.88/1,000 ft ^{3}) x (10^6/MM).
[b]E = Water flow rate (gal/min) x 0.161 x operating hours x ($0.06/kWH).
[c]Maintenance costs for the Centaur and Allison 501 turbines were obtained from the manufacturers. Costs for the MS5001 and MS7001 were estimated based on information about inspections and parts replacement presented in Appendix B. Maintenance for turbines that use diesel fuel are 30 percent higher than costs for comparable turbines using natural gas. No additional maintenance costs were assessed for steam injection.
[d]WT includes treatment chemicals, raw water, sewage disposal, and operating labor.
[e]Raw Water Cost = Water Flow (gal/min) x ($0.384/1,000 gal) x (60 min/hour) x operating hours x 1.29.
[f]Treatment Cost = Water Flow (gal/min) x ($1.97/1,000 gal) x (60 min/hour) x operating hours x 1.29.
[g]Labor Cost for water = Water Flow (gal/min) x ($.70/1,000 gal) x (60 min/hour) x operating hours x 1.29.
Labor Cost for steam = Water Flow (gal/min) x ($.70/1,000 gal) x (60 min/hour) x operating hours x 1.29 x 0.5.
[h]Disposal Cost = Water Flow (gal/min) x ($3.82/1,000 gal) x (60 min/hour) x operating hours x 0.29.
[i]GATI = 0.04 x TCC (TCC is shown in Table 6-4).
[j]CR = 0.1315 x TCC based on an equipment life of 15 years and a 10 percent interest rate.

for each model plant. Annual costs include the fuel penalty; electricity; maintenance requirements; water treatment; overhead, general and administrative, taxes, and insurance; and capital recovery, as discussed in this section.

(1) Fuel Penalty. The reduction in efficiency associated with water injection varies for each turbine model. Based on data in Reference 2, it was estimated that a WFR of 1.0 corresponds to a fuel penalty of 3.5 percent for water injection and 1.0 percent for steam injection. This percentage was multiplied by the actual WFR and the annual fuel cost to

determine the fuel penalty for each model plant. The fuel flow was multiplied by the unit fuel costs to determine the annual fuel costs. As shown in Table 6-3, the natural gas cost is $3.88/1,000 standard cubic feet (scf) and the diesel fuel cost is $0.77/gal.[4,5]

An increase in output from the turbine accompanies the decrease in efficiency. This increase was not considered, however, because not all sites have a demand for the available excess power. In applications such as electric power generation, where the excess power can be used at the site or added to utility power sales, this additional output would serve to decrease or offset the fuel penalty impact.

(2) Electricity Cost. The electricity costs shown in Table 6-5 apply to the feedwater pump(s) for water or steam injection. The pump power requirements are estimated from the pump head (ft) and the water flow rate as shown in the following equation:[2]

$$\text{power pump } (kW_e) = \frac{FR}{3{,}960} \times H \times (S.G.) \times \frac{1}{0.6} \times \frac{0.7457\ kW}{hp} \times \frac{1}{0.9}$$

where:

FR = feedwater flow rate, gal/min (from Table 6-2);
H = total pump head (ft);
S.G. = specific gravity of the feed water;
0.6 = pump efficiency of 60 percent;
0.9 = electric motor efficiency of 90 percent;
3,960 = factor to correct units in FR and H to hp; and
0.7457 = factor to convert hp to kW.

For water injection, the feedwater pump(s) supply treated water to the gas turbine injection system. For steam injection, the feedwater pump(s) supply treated water to the boiler for steam generation. This cost analysis uses a feedwater temperature of 55°C (130°F) with a density of 61.6 lb/ft^3 and a total pump head requirement of 200 pounds per square inch, gauge (psig)

(468 ft).[2] Based on these values, the pump electrical demand for either water or steam injection is calculated as follows:

$$\text{pump power } (kW_e) = \frac{FR \times 468}{3{,}960} \times \frac{61.6}{62.4} \times \frac{1}{0.6} \times 0.7457 \times \frac{1}{0.9}$$

$$= 0.161 \times FR$$

The electrical cost for each model plant is the product of the pump electrical demand, the annual hours of operation, and the unit cost of electricity. The unit cost of electricity, shown in Table 6-3, is $0.06/kWH.[6,7]

Maintenance costs were developed based on information from manufacturers, and water treatment labor costs were estimated based on information from a water treatment vendor. Other costs were developed based on the methodology presented in Reference 2.

No backup steam or electricity costs were developed for water or steam injection because it was assumed that no additional downtime would be required for scheduled inspections and repairs. Maintenance intervals could be scheduled to coincide with the 760 hr/yr of downtime that are currently allocated for scheduled maintenance. If this were done, the annual utilization of the backup source would not increase.

(3) Added Maintenance Costs. Based on discussions with gas turbine manufacturers, additional maintenance is required for some gas turbines with water injection. The analysis procedures used to develop the incremental maintenance costs are presented in Appendix B.

The incremental maintenance cost associated with water injection for natural gas-fueled turbines was provided by the gas turbine manufacturers.[10,20-24] All gas turbine manufacturers contacted stated that there were no incremental maintenance costs for operation with steam injection. Two manufacturers provided maintenance costs for natural gas and oil fuel operation without water injection.[10,20] Using an average of these costs, incremental maintenance costs for water injection are 30 percent higher for

plants that use diesel fuel instead of natural gas. Costs were prorated for model plants that operate less than 8,000 hr/yr.

(4) Water Treatment Costs. Water treatment operating costs include the cost of treatment (e.g., for chemicals and media filters), operating labor, raw water, and wastewater disposal. The raw water flow rate is equal to the treated water flow rate (the water or steam injection rate) plus the flow rate of the wastewater generated in the treatment plant. As noted in Section 6.1, the wastewater flow rate is equal to 29 percent of the injection flow rate. The annual raw water, treated water, and wastewater flow rates were multiplied by the appropriate unit costs in Table 6-3 to determine the annual costs. Water treatment labor costs were calculated at $0.70/1,000 gal for water injection.[25] This cost was multiplied by the total annual treated water flow rate to determine the annual water treatment labor cost for water injection. Labor costs for steam injection were assumed to be half as much as the costs for water injection because it was assumed that the facility already has a water treatment plant for the boiler feedwater. Therefore, the operator requirements would be only those associated with the increase in capacity of the existing treatment plant.

(5) Plant Overhead. This cost is the overhead associated with the additional maintenance effort required for water injection. The cost was calculated as 30 percent of the added maintenance cost from Section 6.1.2.3.[2]

(6) General and Administrative, Taxes, and Insurance Costs (GATI). This cost covers those expenses for administrative overhead, property taxes, and insurance and was calculated as 4 percent of the total capital cost.[2]

(7) Capital Recovery. A capital recovery factor (CRF) was multiplied by the total capital investment to estimate uniform end-of-year payments necessary to repay the investment. The CRF used in this analysis is 0.1315, which is based on an equipment life of 15 years and an interest rate of 10 percent.

(8) Total Annual Cost. This cost is the sum of the annual costs presented in Sections 6.1.2.1 through 6.1.2.7 and is the

total cost that must be paid each year to install and operate water or steam injection NO_x emissions control for a gas turbine.

iii. Emission Reduction and Cost-Effectiveness Summary for Water and Steam Injection

TABLE 6-6. COST-EFFECTIVENESS SUMMARY FOR WATER AND STEAM INJECTION (1990 $)

Model plant	GT model	NO_x emissions[a]				Total NO_x removed, tons/yr	Total annual cost, $	Cost effectiveness, $/ton
		Uncontrolled NO_x		Controlled NO_x				
		ppmv[b]	tons/yr	ppmv	[b] tons/yr			
CON-G-W-3.3	Centaur T4500	130	88.1	42	28.5	59.6	124,000	2,080
CON-G-W-4.0	501-KB5	155	126	42	34.2	91.9	162,000	1,760
CON-G-W-22.7	LM2500	174	581	42	140	441	436,000	989
CON-G-W-26.8	MS5001P	142	723	42	214	509	573,000	1,130
CON-G-W-83.3	ABB GT11N	390	5,410	25	347	5,060	2,910,000	575
CON-G-W-84.7	MS7001E	154	2,170	42	593	1,580	1,480,000	937
CON-G-S-4.0	501-KB5	155	126	42	34.2	91.9	168,000	1,830
CON-G-S-22.7	LM2500	174	581	25	83.5	497	421,000	846
CON-G-S-26.8	MS5001P	142	723	42	214	509	487,000	957
CON-G-S-34.4	LM5000	185	930	25	126	804	692,000	861
CON-G-S-83.3	ABB GT11N	390	5,410	42	583	4,830	1,810,000	375
CON-G-S-84.7	MS7001E	154	2,170	42	593	1,580	1,160,000	734
CON-G-S-161	MS7001F	210	5,150	42	1,030	4,120	1,970,000	478
CON-O-W-3.3	Centaur T4500	179	125	60	41.8	82.9	143,000	1,720
CON-O-W-26.3	MS5001P	211	1,090	65	337	753	754,000	1,000
CON-O-W-83.3	MS7001E	228	3,290	65	938	2,350	1,580,000	672
PKR-G-W-3.3	Centaur T4500	130	22.0	42	7.12	14.9	80,800	5,420
PKR-G-W-26.8	MS5001P	142	181	42	53.5	127	299,000	2,350
PKR-G-W-84.7	MS7001E	154	543	42	148	395	702,000	1,780
PKR-O-W-3.3	Centaur T4500	179	31.2	60	10.5	20.7	86,700	4,180
PKR-O-W-26.3	MS5001P	211	273	65	84.2	189	359,000	1,900
PKR-O-W-84.7	MS7001E	228	822	65	234	588	713,000	1,210
STD-O-W-1.1	Saturn T1500	150	4.97	60	1.99	2.98	48,600	16,300
STD-O-E-28.0	TPM FT4	150	122	50	37.3	84.7	156,000	1,840

[a]Example NO_x emission calculations are given in Appendix A.

[b]Referenced to 15 percent oxygen.

[c]From Table 6-5.

The uncontrolled and controlled NO_x emissions and the annual emission reductions for the model plants are shown in Table 6-6. The emissions, in tons per year (tons/yr), were calculated as shown in Appendix A.

The total annual cost was divided by the annual emission reductions to determine the cost effectiveness for each model plant. For continuous-duty natural gas-fired model plants, the cost-effectiveness figures range from approximately $600 to $2,100 per ton of NO_x removed for water injection, and decrease to approximately $400 to $1,850 per ton for steam injection. The lower range of cost-effectiveness figures for steam injection is primarily due to the greater NO_x reduction achieved with steam injection. For continuous-duty oil-fired model plants, the cost effectiveness ranges from approximately $675 to $1,750 per ton of NO_x removed, which is comparable to figures for gas-fired model plants. The cost-effectiveness figures are higher for gas turbines with lower power outputs because the fixed capital costs associated with wet injection system installation have the greatest impact on the smaller gas turbines.

Cost-effectiveness figures increase as annual operating hours decrease. For turbines operating 2,000 hr/yr, the cost-effectiveness figures are two to nearly three times higher than those for continuous-duty model plants, and increase further for model plants operating 1,000 hr/yr. For the oil-in-water emulsion model plant, the cost effectiveness corresponding to 1,000 annual operating hours is $1,840/ton of NO_x removed. No data were available to prepare a conventional water injection model plant for this turbine to compare the relative cost-effectiveness values.

b. LOW-NO_x COMBUSTORS

Incremental capital costs for low-NO_x combustors relative to standard designs for new applications were provided by three manufacturers for several turbines.[3,14,26] Based on information from the manufacturers, the performance and maintenance requirements for a low-NO_x combustor are expected to be the same as for a standard combustor, and so the only annual cost associated with low-NO_x combustors is the capital recovery. The capital recovery factor is 0.1315, assuming a life of 15 years and an interest rate of 10 percent.

Table 6-7

TABLE 6-7. COST-EFFECTIVENESS SUMMARY FOR DRY LOW-NO_x COMBUSTORS USING NATURAL GAS FUEL (1990 $)

Model plant [a]	GT model	Power output, MW	Annual operating hours	NO_x emissions [b]				NO_x removed, tons/yr	Incremental capital cost,$ [d]	Annual cost, $ [e]	Cost effectiveness, $/ton NO_x removed
				Uncontrolled NO_x		Controlled NO_x					
				ppmv [c]	Tons/yr	ppmv	Tons/yr				
CON-L-3.3-42	Centaur T4500	3.3	8,000	130	88.1	42.0	28.5	59.6	375,000	49,300	827
CON-L-4.0-42	Centaur 'H'	4.0	8,000	105	83.0	42.0	33.2	49.8	400,000	52,600	1,060
CON-L-4.5-42	Taurus	4.5	8,000	114	98.7	42.0	36.4	62.4	425,000	55,900	896
CON-L-8.8-42	Mars T12000	8.8	8,000	178	278	42.0	65.5	212	700,000	92,100	434
CON-L-10-42	Mars T14000	10.0	8,000	199	341	42.0	72.1	269	725,000	95,300	354
CON-L-3.3-25	Centaur T4500	3.3	8,000	130	88.1	25.0 [f]	16.9	71.2	375,000	49,300	693
CON-L-4.0-25	Centaur 'H'	4.0	8,000	105	83.0	25.0 [f]	19.8	63.2	400,000	52,600	832
CON-L-4.5-25	Taurus	4.5	8,000	114	98.7	25.0 [f]	21.7	77.1	425,000	55,900	725
CON-L-8.8-25	Mars T12000	8.8	8,000	178	278	25.0 [f]	39.0	239	700,000	92,100	386
CON-L-10-25	Mars T14000	10.0	8,000	199	341	25.0 [f]	42.9	299	725,000	95,300	319
CON-L-39-25	MS6000	39.0	8,000	220	1,480	25.0	168	1,310	1,400,000	184,000	140
CON-L-83-25	ABB GT11N	83.3	8,000	390	5,420	25.0	347	5,070	2,200,000	289,000	57.0
CON-L-85-25	MS7001E	84.7	8,000	154	2,180	25.0	353	1,830	2,140,000	281,000	154
CON-L-39-9	MS6000	39.0	8,000	220	1,480	9.00	60.6	1,420	1,400,000	184,000	130
CON-L-83-9	ABB GT11N	83.3	8,000	390	5,420	9.00	125	5,290	2,200,000	289,000	54.6
CON-L-85-9	MS7001E	84.7	8,000	154	2,180	9.00	127	2,050	2,140,000	281,000	137
PKR-L-3.3-42	Centaur T4500	3.3	2,000	130	22.0	42.0	7.12	14.9	375,000	49,300	3,310
PKR-L-4.0-42	Centaur 'H'	4.0	2,000	105	20.7	42.0	8.30	12.4	400,000	52,600	4,230
PKR-L-4.5-42	Taurus	4.5	2,000	114	24.7	42.0	9.09	15.6	425,000	55,900	3,590
PKR-L-8.8-42	Mars T12000	8.8	2,000	178	69.4	42.0	16.4	53.1	700,000	92,100	1,740
PKR-L-10-42	Mars T14000	10.0	2,000	199	85.4	42.0	18.0	67.3	725,000	95,300	1,420
PKR-L-3.3-25	Centaur T4500	3.3	2,000	130	22.0	25.0 [f]	4.24	17.8	375,000	49,300	2,770
PKR-L-4.0-25	Centaur 'H'	4.0	2,000	105	20.7	25.0 [f]	4.94	15.8	400,000	52,600	3,330
PKR-L-4.5-25	Taurus	4.5	2,000	114	24.7	25.0 [f]	5.41	19.3	425,000	55,900	2,900
PKR-L-8.8-25	Mars T12000	8.8	2,000	178	69.4	25.0 [f]	9.75	59.7	700,000	92,100	1,540
PKR-L-10-25	Mars T14000	10.0	2,000	199	85.4	25.0 [f]	10.7	74.6	725,000	95,300	1,280
PKR-L-39-25	MS6000	39.0	2,000	220	371	25.0	42.1	328	1,400,000	184,000	560
PKR-L-83-25	ABB GT11N	83.3	2,000	390	1,350	25.0	86.8	1,260	2,200,000	289,000	229
PKR-L-85-25	MS7001E	84.7	2,000	154	540	25.0	88.3	452	2,140,000	281,000	622
*PKR-L-39-9	MS6000	39.0	2,000	220	371	9.00	15.2	355	1,400,000	184,000	518
PKR-L-83-9	ABB GT11N	83.3	2,000	390	1,350	9.00	31.3	1,320	2,200,000	289,000	219
PKR-L-85-9	MS7001E	84.7	2,000	154	540	9.00	31.8	508	2,140,000	281,000	553

[a]Model plant legend: First entry: annual operating hours Second entry: control technique Third entry: power output, in MW Fourth entry: controlled NO_x level, ppmv at 15 percent O
CON - Continuous duty, 8,000 hours L - dry low-NO_x combustor
PKR - peaking/intermittent duty, 2,000 hours

For example, CON-L-3.3-42 designates that the model plant operates 8,000 hours per year, is fitted with a dry low-NO_x combustor, has a power output of 3.3 MW, and has a controlled NO_x level of 42 ppmv.

[b]Example NO_x emission calculations are shown in Appendix A.

[c]Referenced to 15 percent oxygen.

[d]Incremental capital costs were provided by the manufacturers.

presents the uncontrolled and controlled emission levels, the annual emission reductions, incremental costs for a low-NO_x combustor over a conventional design, and the cost effectiveness of low-NO_x combustors for all gas turbine models for which sufficient data were available. Cost-effectiveness figures were calculated for 8,000 and 2,000 hours of operation annually, using controlled NO_x emission levels of 42, 25, and 9 parts per million, by volume (ppmv), referenced to 15 percent oxygen, which are the achievable levels stated by the turbine manufacturers. The cost effectiveness varies according to the uncontrolled NO_x emission level for the conventional combustor design and the achievable controlled emission level for the low-NO_x design. For continuous-duty applications, cost effectiveness for a controlled NO_x emission level of 42 ppmv ranges from $353 to $1,060 per ton of NO_x removed. The cost-effectiveness range decreases to $57 to $832 per ton of NO_x removed for a controlled NO_x emission level of 25 ppmv and decreases further to $55 to $137 per ton of NO_x removed for a 9 ppmv control level. In all cases, the cost effectiveness increases as the operating hours decrease. In general, the cost effectiveness is higher for smaller gas turbines than for larger turbines due to the relatively higher capital cost per kW for low-NO_x combustors for smaller turbines.

The cost-effectiveness range is lower for low-NO_x combustors than for water or steam injection because the total annual costs are lower and, in some cases, the controlled emission levels are

also lower. According to two turbine manufacturers, retrofit costs are 40 to 60 percent greater than the incremental costs shown in Table 6-7 for new installations.[3,14]

c. SELECTIVE CATALYTIC REDUCTION

The costs for SCR for new installations were estimated for all model plants. Retrofit costs for SCR were not available but could be considerably higher than the costs shown for new installations, especially in applications where an existing heat recovery steam generator (HRSG) would have to be moved, modified, or replaced to accommodate the addition of a catalyst reactor.

To date, most gas turbine SCR applications use a base metal catalyst with an operating temperature range that requires cooling of the exhaust gas from the turbine. For this reason, SCR applications to date have been limited to combined cycle or cogeneration applications that include an HRSG, which serves to cool the exhaust gas to temperatures compatible with the catalyst. The introduction of high-temperature zeolite catalysts, however, makes it possible to install the catalyst directly downstream of the turbine, and therefore feasible to use SCR with simple-cycle applications as well as heat recovery applications. As discussed in Section 5.3.2, to date there is at least one gas turbine installation with a high-temperature zeolite catalyst installed downstream of the turbine and upstream of an HRSG. At present, no identified SCR systems are installed in simple-cycle gas turbine applications.

An overview of the procedures used to estimate capital and annual costs are described in Sections 6.3.1 and 6.3.2, respectively; a detailed cost algorithm is presented in Appendix B. The emission reduction and cost-effectiveness calculations are described in Section 6.3.3.

i. <u>Capital Costs</u>

Five documents in the technical literature contained SCR capital costs for 21 gas turbine facilities. Most of these documents presented costs that were obtained from vendors, but some may have also developed at least some costs based on their own experiences.[27-31] Most of the documents presented only the

total capital costs, not costs for individual components, and they did not provide complete descriptions of what the costs included. These costs were plotted on a graph of total capital costs versus gas turbine size. To this graph were added estimates of total installed costs for a high-temperature catalyst SCR system for installation upstream of the HRSG for four turbine installations ranging in size from 4.5 to 83 MW (6,030 to 111,000 hp). These high-temperature SCR system estimates include the catalyst reactor, air injection system for exhaust temperature control, ammonia storage and injection system, instrumentation, and continuous emission monitoring equipment. These SCR costs were estimated by the California Air Resources Board (CARB) in 1991 dollars and are based on NO_x emission levels of 42 ppmv into and 9 ppmv out of the SCR.[35] These estimated costs, shown in Appendix B, fit well within the range of costs from the 21 installations discussed above, and the equation of a line determined by linear regression adequately fits the data ($R^2 = 0.76$) for all 25 points. Based on this graph, the total capital cost for either a base-metal SCR system installed within the HRSG or a high-temperature zeolite catalyst SCR system installed directly downstream of the turbine can be calculated using the equation determined by the linear

TABLE 6-8. PROCEDURES FOR ESTIMATING CAPITAL AND ANNUAL COSTS FOR SCR CONTROL OF NO_X EMISSIONS FROM GAS TURBINES[a]

A. Total capital investment, $[b]	=	(49,700 x TMW) + 459,000
B. Direct annual costs, $/yr		
1. Operating labor[c]	=	(1.0 hr/8 hr-shift) x ($25.60/hr) x (H)
2. Supervisory labor	=	(0.15) x (operating labor)
3. Maintenance labor and materials	=	(1,250 x TMW) + 25,800
4. Catalyst replacement	=	(4,700 x TMW) + 37,200
5. Catalyst disposal[d]	=	(V) x ($15/$ft^3$) x (.2638)
6. Anhydrous ammonia[e]	=	(N) x ($360/ton)
7. Dilution steam[f]	=	(N) x (0.95/0.05) x (MW H_2O/MW NH_3) x ($6/1,000 lb steam) x (2,000 lb/ton)
8. Electricity[g]	=	N/A
9. Performance loss[h]	=	(0.005) x (TMW) x ($0.06/KWH) x (1,000 KW/MW) x (H)
10. Blower (if needed)	=	0.1 x (Performance Loss)
11. Production loss[i]	=	None
C. Indirect annual costs, $/yr		
1. Overhead	=	(0.6) x (all labor and maintenance material costs)
2. Property taxes, insurance, and administration	=	(0.04) x (total capital investment)
3. Capital recovery[j]	=	(0.13147) x [total capital investment - (catalyst replacement/0.2638)]

[a]All costs are in average 1990 dollars.

[b]TMW=turbine output in MW for each model plant.

[c]The annual operating hours are represented by the variable H. The labor rate of $25.60/hr is from Table 6-3.

[d]The catalyst volume in ft^3 is represented by the variable V. The catalyst volume for each model plant is estimated as V = (TMW) x (6,180 ft^3/83 MW).

[e]The ammonia requirement in tons is represented by the variable N and is calculated using a NH_3-to-NO_x molar ratio of 1.0.

The annual tonnage of NO_x is taken from the controlled levels shown in Tables 6-11 and 6-12.

[f]The ammonia is diluted with steam to 5 percent by volume before injection.

[g]The amount of electricity required for ammonia pumps and exhaust fans is not known, but is expected to be small. The electricity cost comprised less than 1 percent of the total annual cost estimated by the South Coast Air Quality Management District (SCAQMD) for SCR applied to a 1.1 MW turbine.

[h]Based on information from three sources, the backpressure from the SCR reduces turbine output by an average of about 0.9 percent.

[i]No production losses are estimated because it is assumed that all SCR maintenance, inspections, cleaning, etc. can be performed during the 760 hours of scheduled downtime per year.

[j]The capital recovery factor for the SCR is 0.13147, based on a 15-year equipment life and 10 percent interest rate. The catalyst is replaced every 5 years. The 0.2638 figure is the capital recovery factor for a 5-year equipment life and a 10 percent interest rate.

regression. This equation is shown in Table 6-8 and was used to calculate the total capital investment for SCR for each model plant shown in Tables 6-9 and 6-10.

TABLE 6-9. CAPITAL AND ANNUAL COSTS FOR SCR USED DOWNSTREAM OF WATER OR STEAM INJECTION (1990 $)

Model plant	GT model	Total capital investment, $[a]	Operating labor, $	Super-visory labor, $	Main-tenance labor & materials, $	Catalyst replace-ment, $	Catalyst disposal, $	Ammonia, $	Dilution steam, $	Perfor-mance loss, $	Blower (if needed), $	Over-head, $	Taxes, insurance & admin, $	Capital recovery, $	Total annual cost, $
CON-G-W-3.3	Centaur T4500	622,000	25,600	3,840	29,900	52,600	963	2,980	1,770	7,850	785	35,600	24,900	55,600	242,000
CON-G-W-4.0	501-KB5	658,000	25,600	3,840	30,800	56,000	1,180	3,570	2,130	9,600	960	36,100	26,300	58,600	255,000
CON-G-W-22.7	LM2500	1,590,000	25,600	3,840	54,100	144,000	6,680	14,700	8,740	54,400	5,440	50,100	63,600	137,000	568,000
CON-G-W-26.8	MS5001P	1,790,000	25,600	3,840	59,300	163,000	7,900	22,400	13,300	64,300	6,430	53,200	71,600	154,000	645,000
CON-G-W-83.3	ABB GT11N	4,600,000	25,600	3,840	130,000	429,000	24,500	29,600	17,600	200,000	20,000	95,700	184,000	391,000	1,550,000
CON-G-W-84.7	MS7001E	4,670,000	25,600	3,840	132,000	435,000	25,000	62,000	36,900	203,000	20,300	96,900	187,000	397,000	1,620,000
CON-G-S-4.0	501-KB5	658,000	25,600	3,840	30,800	56,000	1,180	3,570	2,130	9,600	960	36,100	26,300	58,600	255,000
CON-G-S-22.7	LM2500	1,590,000	25,600	3,840	54,100	144,000	6,680	7,110	4,240	54,400	5,440	50,100	63,600	137,000	556,000
CON-G-S-26.8	MS5001P	1,790,000	25,600	3,840	59,300	163,000	7,900	22,400	13,300	64,300	6,430	53,200	71,600	154,000	645,000
CON-G-S-34.4	LM5000	2,170,000	25,600	3,840	68,900	199,000	10,100	10,700	6,380	82,700	8,270	59,000	86,800	186,000	747,000
CON-G-S-83.3	ABB GT11N	4,600,000	25,600	3,840	130,000	429,000	24,500	61,000	36,300	200,000	20,000	95,700	184,000	391,000	1,600,000
CON-G-S-84.7	MS7001E	4,670,000	25,600	3,840	132,000	435,000	25,000	62,000	36,900	203,000	20,300	96,900	187,000	397,000	1,620,000
CON-G-S-161	MS7001F	8,460,000	25,600	3,840	227,000	794,000	47,400	108,000	64,200	386,000	38,600	154,000	338,000	717,000	2,900,000
CON-O-W-3.3	Centaur T4500	622,000	25,600	3,840	29,900	52,600	963	3,890	2,320	7,850	785	35,600	24,900	55,600	244,000
CON-O-W-26.3	MS5001P	1,770,000	25,600	3,840	58,700	161,000	7,750	32,400	19,300	63,100	6,310	52,900	70,800	152,000	654,000
CON-O-W-83.3	MS7001E	4,600,000	25,600	3,840	130,000	429,000	24,500	90,000	53,800	200,000	20,000	95,700	184,000	391,000	1,650,000
PKR-G-W-3.3	Centaur T4500	622,000	6,400	960	7,470	13,100	241	740	440	1,960	196	8,900	24,900	75,300	141,000
PKR-G-W-26.8	MS5001P	1,790,000	6,400	960	14,800	40,800	1,970	5,600	3,330	16,100	1,610	13,300	71,600	215,000	391,000
PKR-G-W-84.7	MS7001E	4,670,000	6,400	960	32,900	109,000	6,240	15,500	9,240	50,800	5,080	24,200	187,000	560,000	1,010,000
PKR-O-W-3.3	Centaur T4500	622,000	6,400	960	7,470	13,100	241	970	580	1,960	196	8,900	24,900	75,300	141,000
PKR-O-W-26.3	MS5001P	1,770,000	6,400	960	14,700	40,200	1,940	8,100	4,830	15,800	1,580	13,200	70,800	213,000	392,000
PKR-O-W-84.7	MS7001E	4,600,000	6,400	960	32,500	107,000	6,140	22,500	13,440	50,000	5,000	23,900	184,000	552,000	1,000,000
STD-O-W-1.1	Saturn T1500	515,000	3,200	480	3,400	5,310	41.6	185	158	339	33.9	4,250	20,600	65,100	103,000
STD-O-E-28.0	TPM FT4	1,850,000	3,200	480	60,800	21,100	1,030	3,180	2,960	8,400	840	38,700	74,000	233,000	448,000

[a]Costs shown are for SCR systems used downstream of gas turbines with wet injection to achieve controlled NO_x emission levels at the inlet to the SCR as shown in Table 6-6.

TABLE 6-10. CAPITAL AND ANNUAL COSTS FOR SCR USED DOWNSTREAM OF LOW-NO_x COMBUSTION

Model plant [a]	GT model	Total capital invest., $ [b]	Operating labor,$	Super-visory labor, $	Main-tenance labor & materials, $	Catalyst replacement, $	Catalyst disposal, $	Ammonia,$	Dilution steam, $	Perfor-mance loss, $	Blower (if needed), $	Over-head, $	Taxes, insurance & admin., $	Capital recovery, $	Total annual cost, $
CON-L-3.3-42	Centaur T4500	622,000	25,600	3,840	29,900	52,700	970	2,980	1,770	7,920	790	35,600	24,900	55,500	242,000
CON-L-4.0-42	Centaur 'H'	658,000	25,600	3,840	30,800	56,000	1,180	3,470	2,070	9,600	960	36,100	26,300	58,600	255,000
CON-L-4.5-42	Taurus	683,000	25,600	3,840	31,400	58,400	1,330	3,800	2,270	10,800	1,080	36,500	27,300	60,700	263,000
CON-L-8.8-42	Mars T12000	896,000	25,600	3,840	36,800	78,600	2,590	6,850	4,080	21,100	2,110	39,700	35,800	78,600	336,000
CON-L-10-42	Mars T14000	956,000	25,600	3,840	38,300	84,200	2,950	7,530	4,490	24,000	2,400	40,600	38,200	83,700	356,000
CON-L-3.3-25	Centaur T4500	622,000	25,600	3,840	29,900	52,700	970	1,440	860	7,920	790	35,600	24,900	55,500	240,000
CON-L-4.0-25	Centaur 'H'	658,000	25,600	3,840	30,800	56,000	1,180	1,680	1,000	9,600	960	36,100	26,300	58,600	252,000
CON-L-4.5-25	Taurus	683,000	25,600	3,840	31,400	58,400	1,330	1,840	1,100	10,800	1,080	36,500	27,300	60,700	260,000
CON-L-8.8-25	Mars T12000	896,000	25,600	3,840	36,800	78,600	2,590	3,320	1,980	21,100	2,110	39,700	35,800	78,600	330,000
CON-L-10-25	Mars T14000	956,000	25,600	3,840	38,300	84,200	2,950	3,650	2,180	24,000	2,400	40,600	38,200	83,700	350,000
CON-L-39-25	MS6000	2,400,000	25,600	3,840	74,600	221,000	11,490	14,300	8,550	93,600	9,360	62,400	96,000	205,000	826,000
CON-L-83-25	ABB GT11N	4,600,000	25,600	3,840	130,000	429,000	24,540	29,600	17,600	200,000	20,000	95,700	184,000	391,000	1,550,000
CON-L-85-25	MS7001E	4,670,000	25,600	3,840	132,000	435,000	24,960	30,100	17,900	203,000	20,300	96,900	186,800	397,000	1,570,000
PKR-L-3.3-42	Centaur T4500	622,000	6,400	960	7,480	55,100	2,870	740	440	1,980	200	8,900	24,900	54,300	164,000
PKR-L-4.0-42	Centaur 'H'	658,000	6,400	960	7,700	107,000	6,140	870	520	2,400	240	9,000	26,300	33,200	201,000
PKR-L-4.5-42	Taurus	683,000	6,400	960	7,860	109,000	6,240	950	570	2,700	270	9,100	27,300	35,500	207,000
PKR-L-8.8-42	Mars T12000	896,000	6,400	960	9,200	9,300	0	1,710	1,020	5,280	530	9,900	35,800	113,000	193,000
PKR-L-10-42	Mars T14000	956,000	6,400	960	9,580	13,200	240	1,880	1,120	6,000	600	10,200	38,200	119,000	207,000
PKR-L-3.3-25	Centaur T4500	623,000	6,400	960	7,480	14,600	330	360	210	1,980	200	8,900	24,900	74,600	141,000
PKR-L-4.0-25	Centaur 'H'	658,000	6,400	960	7,700	19,600	650	420	250	2,400	240	9,000	26,300	76,800	151,000
PKR-L-4.5-25	Taurus	683,000	6,400	960	7,860	21,100	740	460	270	2,700	270	9,100	27,300	79,300	156,000
PKR-L-8.8-25	Mars T12000	896,000	6,400	960	9,200	9,300	0	830	490	5,280	530	9,900	35,800	113,000	192,000
PKR-L-10-25	Mars T14000	956,000	6,400	960	9,580	13,200	240	910	540	6,000	600	10,200	38,200	119,000	206,000
PKR-L-39-25	MS6000	2,400,000	6,400	960	18,600	14,000	290	3,590	2,140	23,400	2,340	15,600	96,000	309,000	492,000
PKR-L-83-25	ABB GT11N	4,600,000	6,400	960	32,500	14,600	330	7,390	4,410	50,000	5,000	23,900	184,000	598,000	927,000
PKR-L-85-25	MS7001E	4,670,000	6,400	960	32,900	19,600	650	7,520	4,480	50,800	5,080	24,200	186,800	604,000	943,000

[a] See Table 6-7 for model plant legend.

[b] Costs shown are for SCR systems used downstream of gas turbines with dry low-NO_x combustion to achieve controlled NO_x emission levels at the inlet to the SCR as shown in Table 6-7.

ii. Annual Costs

Total annual costs for SCR control were developed following standard EPA procedures described in the OAQPS Control Cost Manual for other types of add-on air pollution control devices (APCD's). Information about annual costs was obtained from the same sources that provided capital costs.[27-31] Total annual costs consist of direct and indirect costs; parameters that make up these categories and the equations for estimating the costs are

presented in Table 6-8 and are discussed below. The annual costs are shown in Tables 6-9 and 6-10 for injection and dry low-NO_x combustion, respectively, for each of the model plants.

(1) Operating and Supervisory Labor. Information about operating labor requirements was unavailable. Most facilities have fully automated controls and monitoring/recording equipment, which minimizes operator attention. Therefore, it was assumed that 1 hr of operator attention would be required during an 8-hr shift, regardless of turbine size. This operating labor requirement is at the low end of the range recommended in the OAQPS Control Cost Manual for other types of APCD's.[7] Operator wage rates were estimated to be $25.60/hr in 1990, based on escalating the costs presented in Reference 2 by 5 percent per year to account for inflation. Supervisory labor costs were estimated to be 15 percent of the operating labor costs, consistent with the OAQPS Control Cost Manual.

(2) Maintenance Labor and Materials. Combined maintenance labor and materials costs for 14 facilities were obtained from four articles, but almost half of the data (6 facilities) were provided by one source.[27-30] The costs were escalated to 1990 dollars assuming an inflation rate of 5 percent per year. All of the data are for facilities that burn natural gas. Provided that ammonium salt formation is avoided by limiting ammonia slip and sulfur content, the cost for operation with natural gas should also apply for distillate oil fuel.[32] Therefore, it was assumed that the cost data also apply to SCR control for turbines that fire distillate oil fuel. The costs were plotted versus the turbine size, and least-squares linear regression was used to determine the equation of the line through the data (see Appendix B). This equation, shown in Table 6-8, was used to estimate the maintenance labor and materials costs shown in Table 6-9 for the model plants.

(3) Catalyst Replacement. Replacement costs were obtained for nine gas turbine facilities, and combined replacement and disposal costs were obtained for another six gas turbine facilities.[27-30] The disposal costs were estimated for the six

facilities as described below and in Appendix B. The replacement costs for these six facilities were then estimated by subtracting the estimated disposal costs from the combined costs. A catalyst life of 5 years was used. All replacement costs were escalated to 1990 dollars assuming a 5 percent annual inflation rate.

The estimated 1990 replacement costs were plotted versus the turbine size, and least-squares linear regression was used to determine the equation of the line through the data (see Appendix B). This equation is shown in Table 6-8 and was used to estimate the catalyst replacement costs shown in Table 6-9 for the model plants.

(4) Catalyst Disposal. Catalyst disposal costs were estimated based on a unit disposal cost of $\$15/ft^3$, which was obtained from a zeolite catalyst vendor.[32] This cost was used for each model plant, but the disposal cost may in fact be higher for catalysts that contain heavy metals and are classified as hazardous wastes. The catalyst volume for each model plant was estimated based on information about the catalyst volume for one facility and the assumption that there is a direct relationship between the catalyst volume and the turbine output (i.e., the design space velocity is the same regardless of the SCR size). At one facility, 175 m^3 (6,180 ft^3) of catalyst is used in the SCR with an 83 MW (111,000 hp) turbine.[33] The disposal cost for this catalyst would be \$92,700, using a cost of $\$15/ft^3$.

(5) Ammonia. The annual ammonia (NH_3) requirement is calculated from the annual NO_x reduction achieved by the SCR system. Based on an NH_3/NO_x molar ratio of 1.0, the annual ammonia requirement, in tons, would equal the annual NO_x reduction, in tons, multiplied by the ratio of the molecular weights for NH_3 and NO_x. Anhydrous ammonia with a unit cost of \$360/ton was used.[34,35] The equation to calculate the annual cost for ammonia is shown in Table 6-8.

(6) Dilution Steam. As indicated in Section 5.3.1, steam is used to dilute the ammonia to about 5 percent by volume before injection into the HRSG. According to the OAQPS Control Cost

Manual, the cost to produce steam, or to purchase it, is about $6/1,000 lb.

(7) Electricity. Electricity requirements to operate such equipment as ammonia pumps and ventilation fans is believed to be small. For one facility, the cost of electricity to operate these components was estimated to make up less than 1 percent of the total annual cost, but it is not clear that the number and size of the fans and pumps represent a typical installation.[27] This cost for electricity is expected to be minor, however, for all installations and was not included in this analysis.

For high-temperature catalysts installed upstream of the HRSG, a blower may be required to inject ambient air into the exhaust to regulate the temperature and avoid temperature excursions above the catalyst design temperature range. The cost to operate the blower is calculated to be 10 percent of the fuel penalty.[35]

(8) Performance Loss. The performance loss due to backpressure from the SCR is approximately 0.5 percent of the turbine's design output.[34-36] To make up for this lost output, it was assumed that electricity would have to be purchased at a cost of $0.06/kWH, as indicated in Table 6-3.

(9) Production Loss. No costs for production losses were included in this analysis. It was assumed that scheduled inspections, cleaning, and other maintenance will coincide with the 760 hr/yr of expected or scheduled downtime. It should be recognized that adding the SCR system increases the overall system complexity and the probability of unscheduled outages. This factor should be taken into account when considering the addition of an SCR system.

(10) Overhead. Standard EPA procedures for estimating annual control costs include overhead costs that are equal to 60 percent of all labor and maintenance material costs.

(11) Property Taxes, Insurance, and Administration. According to standard EPA procedures for estimating annual control costs, property taxes, insurance, and administration

costs are equal to 4 percent of the total capital investment for the control system.

(12) Capital Recovery. The CRF for SCR was estimated to be 0.13147 based on the assumption that the equipment life is 15 years and the interest rate is 10 percent.

iii. Cost Effectiveness for SCR

As indicated in Section 5.4, virtually all gas turbine installations using SCR to reduce NO_x emissions also incorporate wet injection or low-NO_x combustors. The NO_x emission levels into the SCR, therefore, were in all cases taken to be equal to the controlled NO_x emission levels shown for these control techniques in Tables 6-6 and 6-7. The most common controlled NO_x emission limit for gas-fired SCR applications is 9 ppmv, referenced to 15 percent oxygen. The capital costs used in this analysis are expected to correspond to SCR systems sized to reduce controlled NO_x emissions ranging from 25 to 42 ppmv from gas-fired turbines to a controlled level of approximately 9 ppmv downstream of the SCR. Based on the controlled NO_x emission limits established by the Northeast States for Coordinated Air Use Management (NESCAUM), shown in Table 5-3, these SCR systems would reduce NO_x emissions to 18 ppmv for oil-fired applications. Cost-effectiveness figures for SCR in this analysis are therefore calculated based on controlled NO_x emission levels of 9 and 18 ppmv, corrected to 15 percent oxygen, for gas- and oil-fired SCR model plants, respectively.

Cost effectiveness for SCR used downstream of wet injection or dry low-NO_x combustion is shown in Tables 6-11

TABLE 6-11. COST-EFFECTIVENESS SUMMARY FOR SCR USED DOWNSTREAM OF GAS TURBINES WIT H WET INJECTION (1990 $)

Model plant	GT model	Turbine output, MW	NO_x emissions[a]				Total NO_x removed, tons/yr	Total annual cost, $[c]	Cost effective-ness, $/ton
			Inlet to SCR		Downstream of SCR				
			ppmv[b]	tons/yr	ppmv	[b] tons/yr			
CON-G-W-3.3	Centaur T4500	3.3	42	28.5	9.0	6.10	22.4	242,000	10,800
CON-G-W-4.0	501-KB5	4.0	42	34.2	9.0	7.32	26.8	255,000	9,500
CON-G-W-22.7	LM2500	22.7	42	140	9.0	30.0	110	568,000	5,160
CON-G-W-26.8	MS5001P	26.8	42	214	9.0	45.8	168	645,000	3,840
CON-G-W-83.3	ABB GT11N	83.3	25	347	9.0	125	222	1,550,000	6,980
CON-G-W-84.7	MS7001E	84.7	42	593	9.0	127	466	1,620,000	3,480
CON-G-S-4.0	501-KB5	4.0	42	34.2	9.0	7.32	26.8	255,000	9,500
CON-G-S-22.7	LM2500	22.7	25	83.5	9.0	30.0	53.4	556,000	10,400
CON-G-S-26.8	MS5001P	26.8	42	214	9.0	45.8	168	645,000	3,840
CON-G-S-34.4	LM5000	34.4	25	126	9.0	45.2	80.4	747,000	9,290
CON-G-S-83.3	ABB GT11N	83.3	42	583	9.0	125	458	1,600,000	3,490
CON-G-S-84.7	MS7001E	84.7	42	593	9.0	127	466	1,620,000	3,480
CON-G-S-161	MS7001F	161	42	1,030	9.0	221	809	2,900,000	3,580
CON-O-W-3.3	Centaur T4500	3.3	60	41.8	18.0	12.5	29.3	244,000	8,340
CON-O-W-26.3	MS5001P	26.3	65	337	18.0	93.3	244	654,000	2,690
CON-O-W-83.3	MS7001E	83.3	65	938	18.0	260	678	1,650,000	2,430
PKR-G-W-3.3	Centaur T4500	3.3	42	7.12	9.0	1.52	5.59	141,000	25,200
PKR-G-W-26.8	MS5001P	26.8	42	53.5	9.0	11.5	42.0	391,000	9,310
PKR-G-W-84.7	MS7001E	84.7	42	148	9.0	31.8	116	1,010,000	8,670
PKR-O-W-3.3	Centaur T4500	3.3	60	10.5	18.0	3.14	7.32	141,000	19,300
PKR-O-W-26.3	MS5001P	26.3	65	84.2	18.0	23.3	60.9	392,000	6,440
PKR-O-W-84.7	MS7001E	84.7	65	234	18.0	64.9	169	1,000,000	5,900
STD-O-W-1.1	Saturn T1500	1.1	60	1.99	18.0	0.60	1.39	103,000	74,000
STD-O-E-28.0	TPM FT4	28.0	50	37.3	18.0	13.4	23.9	448,000	18,800

[a]Example NO_x emission calculations are shown in Appendix A.
[b]Referenced to 15 percent oxygen.
[c]From Table 6-9.

TABLE 6-12. COST-EFFECTIVENESS SUMMARY FOR SCR USED DOWNSTREAM OF DRY LOW-NO_x COMBUSTION (1990 $)

Model plant[a]	GT model	Turbine output, MW	NO_x emissions[b]						Total NO_x removed, tons/yr	Total annual cost, $[d]	Cost effectiveness, $/ton
			Uncontrolled		Inlet to SCR		Downstream of SCR				
			ppmv[c]	tons/yr	ppmv	tons/yr	ppmv	tons/yr			
CON-L-3.3-42	Centaur T4500	3.3	130	88.1	42	28.5	9.0	6.1	22.4	242,000	10,800
CON-L-4.0-42	Centaur 'H'	4.0	105	83.0	42	33.2	9.0	7.1	26.1	255,000	9,780
CON-L-4.5-42	Taurus	4.5	114	98.7	42	36.4	9.0	7.8	28.6	263,000	9,200
CON-L-8.8-42	Mars T12000	8.8	178	278	42	65.5	9.0	14.0	51.5	336,000	6,530
CON-L-10-42	Mars T14000	10.0	199	341	42	72.1	9.0	15.4	56.6	356,000	6,290
CON-L-3.3-25	Centaur T4500	3.3	130	88.1	25	16.9	9.0	6.1	10.8	240,000	22,100
CON-L-4.0-25	Centaur 'H'	4.0	105	83.0	25	19.8	9.0	7.1	12.6	252,000	19,900
CON-L-4.5-25	Taurus	4.5	114	98.7	25	21.7	9.0	7.8	13.9	260,000	18,800
CON-L-8.8-25	Mars T12000	8.8	178	278	25	39.0	9.0	14.0	25.0	330,000	13,200
CON-L-10-25	Mars T14000	10.0	199	341	25	42.9	9.0	15.4	27.5	350,000	12,800
CON-L-39-25	MS6000	39.0	220	1,480	25	168	9.0	61	108	826,000	7,660
CON-L-83-25	ABB GT11N	83.3	390	5,420	25	347	9.0	125	222	1,550,000	6,970
CON-L-85-25	MS7001E	84.7	154	2,180	25	353	9.0	127	226	1,570,000	6,940
PKR-L-3.3-42	Centaur T4500	3.3	130	22.0	42	7.12	9.0	1.52	5.6	164,000	29,300
PKR-L-4.0-42	Centaur 'H'	4.0	105	20.7	42	8.30	9.0	1.78	6.5	201,000	30,800
PKR-L-4.5-42	Taurus	4.5	114	24.7	42	9.09	9.0	1.95	7.1	207,000	29,000
PKR-L-8.8-42	Mars T12000	8.8	178	69.4	42	16.4	9.0	3.5	12.9	193,000	15,000
PKR-L-10-42	Mars T14000	10.0	199	85.4	42	18.0	9.0	3.9	14.2	207,000	14,600
PKR-L-3.3-25	Centaur T4500	3.3	130	22.0	25	4.24	9.0	1.52	2.7	141,000	52,000
PKR-L-4.0-25	Centaur 'H'	4.0	105	20.7	25	4.94	9.0	1.78	3.2	151,000	47,800
PKR-L-4.5-25	Taurus	4.5	114	24.7	25	5.41	9.0	1.95	3.5	156,000	45,000
PKR-L-8.8-25	Mars T12000	8.8	178	69.4	25	9.75	9.0	3.51	6.2	192,000	30,800
PKR-L-10-25	Mars T14000	10.0	199	85.4	25	10.7	9.0	3.9	6.9	206,000	30,000
PKR-L-39-25	MS6000	39.0	220	371	25	42.1	9.0	15.2	26.9	492,000	18,300
PKR-L-83-25	ABB GT11N	83.3	390	1,350	25	86.8	9.0	31.3	55.6	927,000	16,700
PKR-L-85-25	MS7001E	84.7	154	540	25	88.3	9.0	31.8	56.5	943,000	16,700

[a]See Table 6-7 for model plant legend.

[b]Example NO_x emission calculations are shown in Appendix A.

[c]Referenced to 15 percent oxygen.

[d]From Table 6-10.

and 6-12, respectively. For continuous-duty, natural gas-fired

model plants using water or steam injection,the cost effectiveness for SCR ranges from approximately $3,500 to $10,800 per ton of NO_x removed.

The cost-effectiveness range for SCR installed downstream of continuous-duty, natural gas-fired turbines from 3 to 10 MW (4,000 to 13,400 hp) using dry low-NO_x combustion is $6,290 to $10,800 per ton of NO_x removed for an inlet NO_x emission level of 42 ppmv. The cost-effectiveness range for SCR increases for an

inlet NO_x emission level of 25 ppmv due to the lower NO_x reduction efficiency. For an inlet NO_x level of 25 ppmv, the cost effectiveness ranges from $12,800 to $22,100 per ton of NO_x removed for 3 to 10 MW (4,000 to 13,400 hp) turbines and decreases to $6,940 to $7,660 per ton of NO_x removed for larger turbines ranging from 39 to 85 MW (52,300 to 114,000 hp). As these ranges indicate, the cost effectiveness for SCR is affected by the inlet NO_x emission level and not the type of combustion control technique used for the turbine. The cost effectiveness for continuous-duty, oil-fired model plants ranges from approximately $2,450 to $8,350 per ton of NO_x removed. The SCR cost-effectiveness range for oil-fired applications is lower than that for gas-fired installations in this cost analysis because the same capital costs were used for both fuels (capital costs were not available for applications using only distillate oil fuel). The percent NO_x reduction for oil-fired applications is higher, so the resulting cost-effectiveness figures for oil-fired applications are lower. It should be noted that this higher NO_x reduction for oil-fired applications may require a larger catalyst reactor, at a higher capital cost. As a result, the cost-effectiveness figures may actually be higher than those shown in Table 6-11 for oil-fired applications.

The cost-effectiveness figures are higher for smaller gas turbines because the fixed capital costs associated with the installation of an SCR system have the greatest impact on smaller gas turbines. Cost-effectiveness figures increase as annual operating hours decrease. For turbines operating 2,000 hours per year, cost-effectiveness figures are more than double those for continuous-duty model plants, and they increase even further for model plants operating 1,000 hr/yr.

Because virtually all SCR systems are installed downstream of controlled gas turbines, combined cost-effectiveness figures for wet injection plus SCR and also dry low-NO_x combustion plus SCR have been calculated and are shown in Tables 6-13

TABLE 6-13. COMBINED COST-EFFECTIVENESS SUMMARY FOR WET INJECTION PLUS SCR (1990 $)

Model plant	GT model	Turbine output MW	NO_x emissions[a]						Total NO_x removed, tons/yr[c]	Total annual cost, $[c]	Cost effectiveness, $/ton[c]
			Uncontrolled		Inlet to SCR		Downstream of SCR				
			ppmv[b]	tons/yr	ppmv	tons/yr[b]	ppmv	tons/yr[b]			
CON-G-W-3.3	Centaur T4500	3.3	130	88.1	42	28.5	9.0	6.10	82.0	366,000	4,460
CON-G-W-4.0	501-KB5	4.0	155	126	42	34.2	9.0	7.32	119	417,000	3,510
CON-G-W-22.7	LM2500	22.7	174	581	42	140	9.0	30	551	1,000,000	1,820
CON-G-W-26.8	MS5001P	26.8	142	723	42	214	9.0	46	677	1,220,000	1,800
CON-G-W-83.3	ABB GT11N	83.3	390	5,410	25	347	9.0	125	5,290	4,460,000	843
CON-G-W-84.7	MS7001E	84.7	154	2,170	42	593	9.0	127	2,040	3,100,000	1,520
CON-G-S-4.0	501-KB5	4.0	155	126	42	34.2	9.0	7.32	119	423,000	3,560
CON-G-S-22.7	LM2500	22.7	174	581	25	83.5	9.0	30.0	551	977,000	1,770
CON-G-S-26.8	MS5001P	26.8	142	723	42	214	9.0	45.8	677	1,130,000	1,670
CON-G-S-83.3	LM5000	34.4	185	930	25	126	9.0	45.2	884	1,440,000	1,630
CON-G-S-84.7	ABB GT11N	83.3	390	5,410	42	583	9.0	125	5,290	3,410,000	645
CON-G-S-84.7	MS7001E	84.7	154	2,170	42	593	9.0	127	2,040	2,780,000	1,360
CON-G-S-161	MS7001F	161	210	5,150	42	1,030	9.0	220	4,930	4,870,000	988
CON-O-W-3.3	Centaur T4500	3.3	179	125	60	42	18.0	12.5	112	387,000	3,450
CON-O-W-26.3	MS5001P	26.3	211	1,090	65	337	18.0	93.3	997	1,410,000	1,410
CON-O-W-83.3	MS7001E	83.3	228	3,290	65	938	18.0	260	3,030	3,230,000	1,070
PKR-G-W-3.3	Centaur T4500	3.3	130	22.0	42	7.1	9.0	1.5	20.5	222,000	10,800
PKR-G-W-26.8	MS5001P	26.8	142	181	42	53.5	9.0	11.5	169	690,000	4,080
PKR-G-W-84.7	MS7001E	84.7	154	543	42	148	9.0	31.8	512	1,710,000	3,340
PKR-O-W-3.3	Centaur T4500	3.3	179	31.2	60	10	18.0	3.14	28.1	228,000	8,130
PKR-O-W-26.3	MS5001P	26.3	211	273	65	84	18.0	23.3	250	751,000	3,000
PKR-O-W-84.7	MS7001E	84.7	228	822	65	234	18.0	64.9	757	1,710,000	2,260
STD-O-W-1.1	Saturn T1500	1.1	150	4.97 122	60	1.99	18.0	0.60	4.4	152,000	34,700
STD-O-E-28.0	TPM FT4	28.0	150		50	37.3	18.0	13.4	109	604,000	5,563

[a]Example NO_x emission calculations are shown in Appendix A.

[b]Referenced to 15 percent oxygen.

[c]Total for both wet injection plus SCR control techniques.

TABLE 6-14. COMBINED COST-EFFECTIVENESS SUMMARY FOR DRY LOW-NOx COMBUSTION PLUS SCR (1990 $)

Model plant	GT model	Turbine output MW	Annual operating hours	NO_x emissions[a]						Total NO_x removed, tons/yr[c]	Total annual cost, $[c]	Cost effectiveness, $/ton
				Uncontrolled		Inlet to SCR		Downstream of SCR				
				ppmv[b]	tons/yr	ppmv	tons/yr[b]	ppmv	tons/yr[b]			
CON-L-3.3-42	Centaur T4500	3.3	8,000	130	88.1	42	28.5	9.0	6.1	82.0	291,000	3,550
CON-L-4.0-42	Centaur 'H'	4.0	8,000	105	83.0	42	33.2	9.0	7.1	75.8	308,000	4,060
CON-L-4.5-42	Taurus	4.5	8,000	114	98.7	42	36.4	9.0	7.8	90.9	319,000	3,510
CON-L-8.8-42	Mars T12000	8.8	8,000	178	278	42	65.5	9.0	14.0	264	428,000	1,620
CON-L-10-42	Mars T14000	10.0	8,000	199	341	42	72.1	9.0	15.4	326	451,000	1,380
CON-L-3.3-25	Centaur T4500	3.3	8,000	130	88.1	25	16.9	9.0	6.1	82.0	289,000	3,520
CON-L-4.0-25	Centaur 'H'	4.0	8,000	105	83.0	25	19.8	9.0	7.1	75.8	305,000	4,020
CON-L-4.5-25	Taurus	4.5	8,000	114	98.7	25	21.7	9.0	7.8	90.9	316,000	3,470
CON-L-8.8-25	Mars T12000	8.8	8,000	178	278	25	39.0	9.0	14.0	264	422,000	1,600
CON-L-10-25	Mars T14000	10.0	8,000	199	341	25	42.9	9.0	15.4	326	445,000	1,370
CON-L-39-25	MS6000	39.0	8,000	220	1,480	25	168	9.0	60.6	1,420	1,010,000	710
CON-L-83-25	ABB GT11N	83.3	8,000	390	5,420	25	347	9.0	125	5,290	1,840,000	348
CON-L-85-25	MS7001E	84.7	8,000	154	2,180	25	353	9.0	127	2,050	1,850,000	902
PKR-L-3.3-42	Centaur T4500	3.3	2,000	130	22.0	42	7.1	9.0	1.5	20.5	213,000	10,400
PKR-L-4.0-42	Centaur 'H'	4.0	2,000	105	20.7	42	8.3	9.0	1.8	19.0	254,000	13,400
PKR-L-4.5-42	Taurus	4.5	2,000	114	24.7	42	9.1	9.0	1.9	22.7	263,000	11,600
PKR-L-8.8-42	Mars T12000	8.8	2,000	178	69.4	42	16.4	9.0	3.5	65.9	285,000	4,320
PKR-L-10-42	Mars T14000	10.0	2,000	199	85.4	42	18.0	9.0	3.9	81.5	302,000	3,710
PKR-L-3.3-25	Centaur T4500	3.3	2,000	130	22.0	25	4.2	9.0	1.5	20.5	190,000	9,300
PKR-L-4.0-25	Centaur 'H'	4.0	2,000	105	20.7	25	4.9	9.0	1.8	19.0	204,000	10,800
PKR-L-4.5-25	Taurus	4.5	2,000	114	24.7	25	5.4	9.0	1.9	22.7	212,000	9,300
PKR-L-8.8-25	Mars T12000	8.8	2,000	178	69.4	25	9.8	9.0	3.5	65.9	284,000	4,300
PKR-L-10-25	Mars T14000	10.0	2,000	199	85.4	25	10.7	9.0	3.9	81.5	301,000	3,700
PKR-L-39-25	MS6000	39.0	2,000	220	371	25	42.1	9.0	15.2	355	680,000	1,910
PKR-L-83-25	ABB GT11N	83.3	2,000	390	1,350	25	86.8	9.0	31.3	1,320	1,220,000	924
PKR-L-85-25	MS7001E	84.7	2,000	154	540	25	88.3	9.0	31.8	508	1,220,000	2,400

[a]Example NO_x emission calculations are shown in Appendix A.

[b]Referenced to 15 percent oxygen.

[c]Total for both dry low-NO_x combustion plus SCR control techniques.

and 6-14, respectively. These combined cost-effectiveness

figures are calculated by dividing the sum of the total annual costs by the

sum of the annual reduction of NO_x emissions for the combined emission control techniques. For continuous-duty, natural gas-fired model plants, the combined cost-effectiveness figures for wet injection plus SCR range from approximately $650 to $4,500 per ton of NO_x removed. For continuous-duty, oil-fired model plants, the combined cost effectiveness ranges from approximately $1,100 to $3,550 per ton of NO_x removed. The combined cost-effectiveness figures for dry low-NO_x combustion plus SCR for continuous-duty, natural gas-fired model plants range from approximately $350 to $3,550 per ton of NO_x removed.

The combined cost-effectiveness figures increase with decreasing turbine size and annual operating hours. Data were not available to quantify the wet injection requirements and controlled emissions levels for oil-fired turbines with low-NO_x combustors, so cost-effectiveness figures were not tabulated for this control scenario.

d. OFFSHORE TURBINES

The only available information about the cost of NO_x controls for offshore gas turbines was presented in a report prepared for the Santa Barbara County Air Pollution Control District (SBCAPCD) in California.[37] The performance and cost of about 20 NO_x control techniques for a 2.8 MW (3,750 hp) turbine were described in the report. Wet injection and SCR were included in the analysis; low-NO_x combustors were not. The costs from the report are presented in Table 6-15

TABLE 6-15. PROJECTED WET INJECTION AND SCR COSTS FOR AN OFFSHORE GAS TURBINE[a]

	Wet injection costs	SCR costs
Capital cost, $	70,000	585,000
Annual costs, $/yr		
Ammonia	N/A[b]	3,050[c]
Catalyst replacement	N/A	28,000
Operating and maintenance[d]	24,600	18,000
Fuel penalty[e]	10,500	5,000
Capital recovery[f]	14,000	117,000
Total annual costs, $/yr	49,100	171,000

[a]Costs are for a 2.8 MW gas turbine and are obtained from Reference 37.
[b]N/A = Not applicable.
[c]Ammonia cost is based on $150/ton and 0.4 lb NH_3/lb NO_X.
[d]Operating and maintenance cost for SCR is estimated as 3 percent of the total capital investment.
[e]Fuel penalty is estimated as 2 percent of the annual fuel consumption for wet injection and 1 percent for SCR.
[f]Capital recovery is estimated based on an equipment life of 8 years and an interest rate of 13 percent.

without adjustment because there is insufficient cost information to know what adjustments need to be made. Additionally, insufficient information is available to scale up these costs for larger turbines. The water and steam injection costs and SCR costs for offshore applications are discussed in Sections 6.4.1 and 6.4.2, respectively.

i. Wet Injection

The report prepared for SBCAPCD assumed water injection costs are the same as steam injection costs. The report did not describe the components in the capital cost analysis for these injection systems, but the results are much lower than those that

would be estimated by the procedures described in Section 6.1.1 of this report. The authors may have assumed that the engine-mounted injection equipment cost was included in the turbine capital cost and that a less rigorous water treatment process is installed. Annual costs are also much lower than those that would be estimated by the procedures described in Section 6.1.2 of this report. There are at least three reasons for the difference: (1) the low capital cost leads to a low CRF, even though the turbine life was assumed to be only 8 years; (2) overhead costs and taxes, insurance, and administration costs are not considered; and (3) the capacity factor is only 50 percent (i.e., about 4,400 hr/yr, vs. 8,000 hr/yr, as in Section 6.1.2). The turbine life was only 8 years, which may correspond to a typical service life of an offshore platform.

ii. Selective Catalytic Reduction

The total capital costs presented in the report for SBCAPCD are similar to those that would be estimated by the procedures in Section 6.2.1 of this report. However, it appears that $150,000 of the total in Reference 37 is for structural modifications to the platform and $75,000 is for retrofit installation. When the difference in the load factor is taken into account, some of the annual costs are similar to those that would be estimated by the procedures in Section 6.2.2 for a similarly sized turbine. The catalyst replacement cost, however, is much lower; neither the type of catalyst nor the replacement frequency were identified. Ammonia costs are lower because the uncontrolled NO_x emission level was assumed to be 110 ppmv instead of 150 ppmv and because a unit cost of $150/ton was used instead of $400/ton. The reference does not indicate whether or not catalyst disposal, overhead, taxes, freight, and administration costs were considered. Capital recovery costs are higher because the equipment life is assumed to be only 8 years on the offshore platform.

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7..0 ENVIRONMENTAL AND ENERGY IMPACTS

This chapter presents environmental and energy impacts for the nitrogen oxide (NO_x) emissions control techniques described in Chapter 5.0. These control techniques are water or steam injection, dry low-NO_x combustors, and selective catalytic reduction (SCR). The impacts of the control techniques on air pollution, solid waste disposal, water pollution, and energy consumption are discussed.

The remainder of this chapter is organized in five sections. Section 7.1 presents the air pollution impacts; Section 7.2 presents the solid waste disposal impacts; Section 7.3 presents the water pollution impacts; and Section 7.4 presents the energy consumption impacts. References for the chapter are listed in Section 7.5.

a. AIR POLLUTION

i. Emission Reductions

Applying any of the control techniques discussed in Chapter 5 will reduce NO_x emissions from gas turbines. These emission reductions were estimated for the model plants presented in Table 6-1 and are shown in Table 7-1. For each model plant, the uncontrolled and controlled emissions, emission reductions, and percent reductions are presented. The following paragraphs discuss NO_x emission reductions for each control technique.

Nitrogen oxide emission reductions for water or steam injection are estimated as discussed in Section 6.1.3. The percent reduction in emissions from uncontrolled levels varies for each model plant ranging, from 60 to 96 percent. This reduction depends on each model's uncontrolled emissions, the

TABLE 7-1. MODEL PLANT UNCONTROLLED AND CONTROLLED NO_x EMISSIONS FOR AVAILABLE NO_x CONTROL TECHNIQUES

Gas turbine model	Annual operating hours	Type of wet injection	Annual emissions[a]	Uncontrolled NO_x emissions,[a] tons/yr	Controlled NO_x emissions, tons/year					SCR NH_3 emissions @ SLIP = 10 ppm (tons/yr)[c]
					Wet injection to levels in Table 6-6	Dry low-NO_x combustor to 42 ppmv	Dry low-NO_x combustor to 25 ppm	Dry low-NO_x combustor to 9 ppmv	NO_x emissions, wet injection + SCR[b]	
Centaur T4500	8,000	Water	Emissions, tons/yr	88.1	28.5	28.5	16.9	NA[d]	6.10	2.92
3.3 MW			Reduction, tons/yr		59.6	59.6	71.2	_	22.4	
Gas fuel			Total reduction, %		68%	68%	81%	_	93%	
501-KB5	8,000	Water	Emissions, tons/yr	126	34.2	NA	NA	NA	7.32	2.58
4.0 MW			Reduction, tons/yr		91.8	_	_	_	26.9	
Gas fuel			Total reduction, %		73%	_	_	_	94%	
LM2500	8,000	Water	Emissions, tons/yr	581	140	NA	NA	NA	30.0	11.2
22.7 MW			Reduction, tons/yr		441	_	_	_	110	
Gas fuel			Total reduction, %		76%	_	_	_	95%	
MS5001P	8,000	Water	Emissions, tons/yr	723	214	NA	NA	NA	45.8	20.4
26.8 MW			Reduction, tons/yr		509	_	_	_	168	
Gas fuel			Total reduction, %		70%	_	_	_	94%	
ABB GT11N	8,000	Water	Emissions, tons/yr	5,410	347	NA	347	125	125	51.7
83.3 MW			Reduction, tons/yr		5,060	_	5060	5290	222	
Gas fuel			Total reduction, %		94%	_	94%	98%	98%	
MS7001E	8,000	Water	Emissions, tons/yr	2,170	593	NA	353	127	127	49.6
84.7 MW			Reduction, tons/yr		1580	_	1820	2040	466	
Gas fuel			Total reduction, %		73%	_	84%	94%	94%	
501-KB5	8,000	Steam	Emissions, tons/yr	126	34.2	NA	NA	NA	7.32	2.58
4.0 MW			Reduction, tons/yr		92	_	_	_	26.9	
Gas fuel			Total reduction, %		73%	_	_	_	94%	
LM2500	8,000	Steam	Emissions, tons/yr	581	83.5	NA	NA	NA	30.0	11.2
22.7 MW			Reduction, tons/yr		498	_	_	_	53.5	
Gas fuel			Total reduction, %		86%	_	_	_	95%	
MS5001P	8,000	Steam	Emissions, tons/yr	723	214	NA	NA	NA	45.8	20.4
26.8 MW			Reduction, tons/yr		509	_	_	_	168	
Gas fuel			Total reduction, %		70%	_	_	_	94%	

TABLE 7-1. (continued)

Gas turbine model	Annual operating hours	Type of wet injection	Annual emissions[a]	Uncontrolled NO_x emissions,[a] tons/yr	Controlled NO_x emissions, tons/year					SCR NH_3 emissions @ SLIP = 10 ppm (tons/yr)[c]
					Wet injection to levels in Table 6-6	Dry low-NO_x combustor to 42 ppmv	Dry low-NO_x combustor to 25 ppm	Dry low-NO_x combustor to 9 ppmv	NO_x emissions, wet injection + SCR[b]	
LM5000	8,000	Steam	Emissions, tons/yr	930	126	NA	NA	NA	45.2	20.5
34.4 MW			Reduction, tons/yr		804	_	_	_	80.8	
Gas fuel			Total reduction, %		86%	_	_	_	95%	
ABB GT11N	8,000	Steam	Emissions, tons/yr	5,410	583	NA	347	125	125	51.7
83.3 MW			Reduction, tons/yr		4830	_	5060	5290	458	
Gas fuel			Total reduction, %		89%	_	94%	98%	98%	
MS7001E	8,000	Steam	Emissions, tons/yr	2,170	593	NA	353	127	127	49.6
84.7 MW			Reduction, tons/yr		1580	_	1820	2040	466	
Gas fuel			Total reduction, %		73%	_	84%	94%	94%	
MS7001F	8,000	Steam	Emissions, tons/yr	5,150	1,030	NA	610	NA	221	71.7
161 MW			Reduction, tons/yr		4120	_	4540	_	809	
Gas fuel			Total reduction, %		80%	_	88%	_	96%	
Centaur T4500	8,000	Water	Emissions, tons/yr	125	41.8	NA	NA	NA	12.5	2.9
3.3 MW			Reduction, tons/yr		83.2	_	_	_	29.3	
Oil fuel			Total reduction, %		67%	_	_	_	90%	
MS5001P	8,000	Water	Emissions, tons/yr	1,090	337	NA	NA	NA	46.6	20.4
26.3 MW			Reduction, tons/yr		753	_	_	_	290	
Oil fuel			Total reduction, %		69%	_	_	_	96%	
MS7001E	8,000	Water	Emissions, tons/yr	3,290	938	NA	NA	NA	130	49.6
83.3 MW			Reduction, tons/yr		2350	_	_	_	808	
Oil fuel			Total reduction, %		71%	_	_	_	96%	
Centaur T4500	2,000	Water	Emissions, tons/yr	22.0	7.1	NA	NA	NA	1.5	0.7
3.3 MW			Reduction, tons/yr		14.9	_	_	_	6	
Gas fuel			Total reduction, %		68%	_	_	_	93%	
MS5001P	2,000	Water	Emissions, tons/yr	181	53.5	NA	NA	NA	11.5	5.1
26.8 MW			Reduction, tons/yr		128	_	_	_	42	
Gas fuel			Total reduction, %		70%	_	_	_	94%	

TABLE 7-1. (continued)

Gas turbine model	Annual operating hours	Type of wet injection	Annual emissions[a]	Uncontrolled NO_x emissions,[a] tons/yr	Controlled NO_x emissions, tons/year					SCR NH_3 emissions @ SLIP = 10 ppm (tons/yr)[c]
					Wet injection to levels in Table 6-6	Dry low-NO_x combustor to 42 ppmv	Dry low-NO_x combustor to 25 ppm	Dry low-NO_x combustor to 9 ppmv	NO_x emissions, wet injection + SCR[b]	
MS7001E	2,000	Water	Emissions, tons/yr	543	148	NA	88	32	31.8	12.4
84.7 MW			Reduction, tons/yr		395	_	455	511	116	
Gas fuel			Total reduction, %		73%	_	84%	94%	94%	
Centaur T4500	2,000	Water	Emissions, tons/yr	31.2	10.0	NA	NA	NA	3.14	0.7
3.3 MW			Reduction, tons/yr		21.2	_	_	_	6.9	
Oil fuel			Total reduction, %		68%	_	_	_	90%	
MS5001P	2,000	Water	Emissions, tons/yr	273	84	NA	NA	NA	23.3	5.1
26.8 MW			Reduction, tons/yr		189	_	_	_	61	
Oil fuel			Total reduction, %		69%	_	_	_	91%	
MS7001E	2,000	Water	Emissions, tons/yr	822	234	NA	NA	NA	64.9	12.4
84.7 MW			Reduction, tons/yr		588	_	_	_	169	
Oil fuel			Total reduction, %		72%	_	_	_	92%	
SATURN T1500	1,000	Water	Emissions, tons/yr	5.00	1.99	NA	NA	NA	0.30	0.13
1.1 MW			Reduction, tons/yr		3	_	_	_	1.7	
Oil fuel			Total reduction, %		60%	_	_	_	94%	
TPM FT4	1,000	Water-in-	Emissions, tons/yr	977	37.3	NA	NA	NA	6.72	NC[e]
28.0 MW		oil	Reduction, tons/yr		940	_	_	_	30.6	_
Oil fuel		emulsion	Total reduction, %		96%	_	_	_	99%	_

[a]Uncontrolled and controlled NO_x emissions are from cost-effectiveness tables in Chapter 6.

[b]Controlled NO_x emission level for wet injection plus SCR is 9 ppmv for natural gas fuel and 18 ppmv for distillate oil fuel.

[c]Ammonia emissions, in tons per year = (SLIP, ppmv) x (MM/1,000,000) x (GT exhaust,lb/sec) x (MW NH3 = 15/MW exhaust = 28.6) x (3,600 sec/hr) x (ton/2,000 lb) x (annual operating hrs).

[d]NA-control technology not available for this model plant.

[e]NC-data not available to calculate emissions for this control scenario.

water-to-fuel ratio (WFR), and type of fuel and whether water or steam is injected.

Achievable emission levels from gas turbines using dry low-NO_x combustors were obtained from manufacturers. Controlled NO_x levels of 42, 25, and 9 parts per million, by volume (ppmv), referenced to 15 percent oxygen, were reported by the various turbine manufacturers, and each of these levels is shown in Table 7-1, where applicable, for each model plant. The percent reduction in NO_x emissions from uncontrolled levels for gas turbines using these combustors ranges from 68 to 98 percent. Virtually all SCR units installed in the United States are used in combination with either wet controls or combustion controls. For this analysis, emission reductions were calculated for SCR in combination with water or steam injection. Using the turbine manufacturers' guaranteed NO_x emissions figures for wet injection and a controlled NO_x emission level of 9 ppmv, referenced to 15 percent oxygen, exiting the SCR, the percent reduction in NO_x emissions for this combination of control techniques ranges from 93 to 99 percent.

Estimated ammonia (NH_3) emissions, in tons per year, corresponding to ammonia slip from the SCR system are also shown in Table 7-1. These estimates are based on an ammonia slip level of 10 ppmv, consistent with information and data presented in Section 5.4. For continuous-duty model plants, the annual NH_3 emissions range from approximately 3 tons for a 3.3 megawatt (MW) (4,425 horsepower [hp]) model plant to 72 tons for a 160 MW (215,000 hp) model plant.

ii. Emissions Trade-Offs

The formation of both thermal and fuel NO_x depends upon combustion conditions. Water/steam injection, lean combustion, and reduced residence time modify combustion conditions to reduce the amount of NO_x formed. These combustion modifications may increase carbon monoxide (CO) and unburned hydrocarbon (HC) emissions. Using SCR to control NO_x emissions produces ammonia emissions. The impacts of these NO_x controls on CO, HC, and ammonia emissions are discussed below.

(1) Impacts of Wet Controls on CO and HC Emissions. As discussed in Section 5.1.5, wet injection may increase CO and HC emissions. Injecting water or steam into the flame area of a turbine combustor lowers the flame temperature and thereby reduces NO_x emissions. This reduction in temperature to some extent inhibits complete combustion, resulting in increased CO and HC emissions. Figure 5-12 shows the impact of water and steam injection on CO emissions for production gas turbines.[2] The impact of steam injection on CO emissions is less than that of water injection. As seen in Figure 5-12, CO emissions increase with increasing WFR's. Wet injection increases HC emissions to a lesser extent than it increases CO emissions. Figure 5-13 shows the impact of water injection on HC emissions for one turbine. In cases where water and steam injection result in excessive CO and HC emissions, an oxidation catalyst (add-on control) can be installed to reduce these emissions by converting the CO and HC to water (H_2O) and carbon dioxide (CO_2).

(2) Impacts of Combustion Controls on CO and HC Emissions. As discussed in Section 5.2.1, the performance of lean combustion in limiting NO_x emissions relies in part on reduced equivalence ratios. As the equivalence ratio is reduced below the stoichiometric level of 1.0, combustion flame temperatures drop, and as a result NO_x emissions are reduced. Shortening the residence time in the high-temperature flame zone also will reduce the amount of thermal NO_x formed. These lower equivalence ratios and/or reduced residence time, however, may result in incomplete combustion, which may increase CO and HC emissions. The extent of the increase in CO and HC emissions is specific to each turbine manufacturer's combustor designs and therefore varies for each turbine model. As with wet injection, if necessary, an oxidation catalyst can be installed to reduce excessive CO and HC emissions by converting the CO and HC to CO_2 and H_2O.

(3) Ammonia Emissions from SCR. The SCR process reduces NO_x emissions by injecting NH_3 into the flue gas. The NH_3 reacts with NO_x in the presence of a catalyst to form H_2O and nitrogen

(N_2). The NO_x removal efficiency of this process is partially dependent on the NH_3/NO_x ratio. Increasing this ratio reduces NO_x emissions but increases the probability that unreacted ammonia will pass through the catalyst unit into the atmosphere (known as ammonia "slip"). Some ammonia slip is unavoidable because of ammonia injection control limitations and imperfect distribution of the reacting gases. A properly designed SCR system will limit ammonia slip to less than 10 ppmv (see Section 5.4).

b. SOLID WASTE DISPOSAL

Catalytic materials used in SCR units for gas turbines include precious metals (e.g., platinum), zeolites, and heavy metal oxides (e.g., vanadium, titanium). Vanadium pentoxide, the most commonly used SCR catalyst in the United States, is identified as an acute hazardous waste under RCRA Part 261, Subpart D - Lists of Hazardous Wastes. The Best Demonstrated Available Technology (BDAT) Treatment Standards for Vanadium P119 and P120 states that spent catalysts containing vanadium pentoxide are not classified as hazardous waste.[1] State and local regulatory agencies, however, are authorized to establish their own hazardous waste classification criteria, and spent catalysts containing vanadium pentoxide may be classified as a hazardous waste in some areas. Although the actual amount of vanadium pentoxide contained in the catalyst bed is small, the volume of the catalyst unit containing this material is quite large and disposal can be costly. Where classified by State or local agencies as a hazardous waste, this waste may be subject to the Land Disposal Restrictions in 40 CFR Part 268, which allows land disposal only if the hazardous waste is treated in accordance with Subpart D - Treatment Standards. Such disposal problems are not encountered with other catalyst materials, such as precious metals and zeolites, because these materials are not hazardous wastes.

c. WATER USAGE AND WASTE WATER DISPOSAL

Water availability and waste water disposal are environmental factors to be considered with wet injection. The impact of water usage on the water supply at some remote sites,

in small communities, or in areas where water resources may be limited is an environmental factor that should be examined when considering wet injection. The volume of water required for wet injection is shown in Table 7-2

TABLE 7-2. WATER AND ELECTRICITY CONSUMPTION FOR NO_x CONTROL TECHNIQUES

Gas turbine model[a]	Turbine power output, MW	Annual operating hours	Fuel type	Type of emission control	Total water flow, gal/min[a]	Waste water flow, gal/min[b]	Water pump power, kW[c]	Wet injection power consumption, kW-hr/yr[d]	SCR power penalty, kW-hr/yr[e]
Centaur T4500	3.3	8,000	Gas	Water inj.	2.5	0.73	0.40	3,220	132,000
501-KB5	4.0	8,000	Gas	Water inj.	3.94	1.14	0.63	5,070	160,000
LM2500	22.7	8,000	Gas	Water inj.	14.8	4.29	2.38	19,100	908,000
MS5001P	26.8	8,000	Gas	Water inj.	22.2	6.44	3.57	28,600	1,070,000
ABB GT11N	83.3	8,000	Gas	Water inj.	154	44.7	24.8	198,000	3,330,000
MS7001E	84.7	8,000	Gas	Water inj.	69.2	20.1	11.1	89,100	3,390,000
501-KB5	4.0	8,000	Gas	Steam inj.	7.38	2.14	1.19	9,510	160,000
LM2500	22.7	8,000	Gas	Steam inj.	29.5	8.56	4.75	38,000	908,000
MS5001P	26.8	8,000	Gas	Steam inj.	33.3	9.66	5.36	42,900	1,070,000
LM5000	34.4	8,000	Gas	Steam inj.	50.8	14.7	8.18	65,400	1,380,000
ABB GT11N	83.3	8,000	Gas	Steam inj.	178	51.6	28.7	229,000	3,330,000
MS7001E	84.7	8,000	Gas	Steam inj.	104	30.2	16.7	134,000	3,390,000
MS7001F	161	8,000	Gas	Steam inj.	199	57.7	32.0	256,000	6,440,000
Centaur T4500	3.3	8,000	Oil	Water inj.	2.76	0.80	0.44	3,550	132,000
MS5001P	26.3	8,000	Oil	Water inj.	26.7	7.74	4.30	34,400	1,050,000
MS7001E	83.3	8,000	Oil	Water inj.	63.8	18.5	10.3	82,200	833,000
Centaur T4500	3.3	2,000	Gas	Water inj.	2.50	0.73	0.40	3,220	33,000
MS5001P	26.3	2,000	Gas	Water inj.	22.2	6.44	3.57	28,600	263,000
MS7001E	84.7	2,000	Gas	Water inj.	69.2	20.1	11.1	89,100	847,000
Centaur T4500	3.3	2,000	Oil	Water inj.	2.76	0.80	0.44	3,550	33,000
MS5001P	26.3	2,000	Oil	Water inj.	26.7	7.74	4.30	34,400	263,000
MS7001E	84.7	2,000	Oil	Water inj.	63.8	18.5	10.3	82,200	847,000
SATURN T1500	1.1	1,000	Oil	Water inj.	0.81	0.23	0.13	1,040	5,500
TPM FT4	28.0	1,000	Oil	Water-in-oil emulsion	21.7	6.29	3.49	27,900	140,000

[a]From Table 6-2.

[b]Calculated as 29 percent of the total water flow.

[c]Power requirement for water pump is calculated as shown in Section 6.1.2.2.

for each model plant.

Water purity is essential for wet injection systems in order to prevent erosion and/or the formation of deposits in the hot sections of the gas turbine. Water treatment systems are used to achieve water quality specifications set by gas turbine manufacturers. Table 5-4 summarizes these specifications for six manufacturers.

Discharges from these water treatment systems have a potential impact on water quality. As indicated in Section 6.1, approximately 29 percent of the treated water flow rate (22.5 percent of the raw water flow rate) is considered to be discharged as wastewater. The wastewater flow rates for each of the model plants with a water or steam injection control system are estimated using this factor, and the results are presented in Table 7-2. The wastewater contains increased levels of those pollutants in the raw water (e.g., calcium, silica, sulfur, as listed in Table 5-4) that are removed by the water treatment system, along with any chemicals introduced by the treatment process. Based on a wastewater flowrate equal to 29 percent of the influent raw water, the concentration of pollutants discharged from the water treatment system is approximately three times higher than the pollutant concentrations in the raw water.

The impacts of these pollutants on water quality are site-specific and depend on the type of water supply and on the discharge restrictions. Influent water obtained from a municipality will not contain high concentrations of pollutants. However, surface water or well water used at a remote site might contain high pollutant concentrations and may require additional pretreatment to meet the water quality specifications set by

manufacturers. This additional pretreatment will increase the pollutant concentrations of the wastewater discharge. Wastewater discharges to publicly-owned treatment works (POTW's) must meet the requirements of applicable Approved POTW Pretreatment Programs.

d. ENERGY CONSUMPTION

Additional fuel and electrical energy is required over baseline for wet injection controls, while additional electrical energy is required for SCR controls. The following paragraphs discuss these energy consumption impacts.

Injecting water or steam into the turbine combustor lowers the net cycle efficiency and increases the power output of the turbine. The thermodynamic efficiency of the combustion process is reduced because energy that could otherwise be available to perform work in the turbine must now be used to heat the water/steam. This lower efficiency is seen as an increase in fuel use. Table 5-10 shows the impacts of wet injection on gas turbine performance for one manufacturer. This table shows a 2 to 4 percent loss in efficiency associated with WFR's required to achieve NO_x emission levels of 25 to 42 ppmv in gas turbines burning natural gas. The actual efficiency loss is specific to each turbine model but generally increases with increasing WFR's and is higher for water injection than for steam injection (additional energy is required to heat and vaporize the water). One exception to this efficiency penalty occurs with steam injection, in which exhaust heat from the gas turbine is used to generate the steam for injection. If the heat recovered in generating the steam would otherwise be exhausted to atmosphere, the result is an increase in net cycle efficiency.

The energy from the increased mass flow and heat capacity of the injected water/steam can be recovered in the turbine, resulting in an increase in power output accompanying the reduced efficiency of the turbine (shown in Table 5-10 for one manufacturer). This increase in power output can be significant and could lessen the impact of the loss in efficiency if the facility has a demand for the available excess power.

Water and steam injection controls also require additional electrical energy to operate the water injection feed water pumps. The annual electricity usage for each model is the product of the pump power demand, discussed in Section 6.1.2.2, and the annual hours of operation. Table 7-2 summarizes this electricity usage for each of the model plants.

For SCR units, additional electrical energy is required to operate ammonia pumps and ventilation fans. This energy requirement, however, is believed to be small and was not included in this analysis.

The increased back-pressure in the turbine exhaust system resulting from adding an SCR system reduces the power output from the turbine. As discussed in Section 6.3.2.9, the power output is typically reduced by approximately 0.5 percent. This power penalty has been calculated for each model plant and is shown in Table 7-2.

e. REFERENCE FOR CHAPTER 7

1.. 55 FR 22276, June 1, 1990.

APPENDIX A

Exhaust NO_x emission levels were provided by gas turbine manufacturers in units of parts per million, by volume (ppmv), on a dry basis and corrected to 15 percent oxygen. A method of converting these exhaust concentration levels to a mass flow rate of pounds of NO_x per hour (lb NO_x/hr) was provided by one gas turbine manufacturer.[1] This method uses an emission index ($EINO_x$), in units of lb NO_x/1,000 lb fuel, which is proportional to the exhaust NO_x emission levels in ppmv by a constant, K. The relationship between $EINO_x$ and ppmv for NO_x emissions is stated in Equation 1 below and applies for complete combustion of a hydrocarbon fuel and combustion air having no CO_2 and an O_2 mole percent of 20.95:

$$\frac{NO_x \text{ Ref. } 15\% \ 0_2}{EINO_x} = K \qquad \text{Equation 1}$$

where: NO_x Ref. 15% 0_2 = NO_x, ppmvd @15% O_2 (provided by gas turbine manufacturers);

$EINO_x$ = NO_x emission index, lb NO_x/1,000 lb fuel; and

K = constant, based on the molar hydrocarbon

ratio of the fuel.

The derivation of Equation 1 was provided by the turbine manufacturer and is based on basic thermodynamic laws and supported by test data provided by the manufacturer. According to the manufacturer, this equation can be used to estimate NO_x emissions for operation with or without water/steam injection.

Equation 1 shows that NO_x emissions are dependent only upon the molar hydrocarbon ratio of the fuel and are independent of the air/fuel ratio (A/F). The equation therefore is valid for all gas turbine designs for a given fuel. The validity of this approach to calculate NO_x emissions was supported by a second

turbine manufacturer.[2] Values for K were provided for several fuels and are given below:[1,2]

Pipeline quality natural gas:

K = 12.1

Distillate fuel oil No. 1 (DF-1):

K = 13.1

Distillate fuel oil No. 2 (DF-2):

K = 13.2

Jet propellant No. 4 (JP-4):

K = 13.0

Jet propellant No. 5 (JP-5):

K = 13.1

Methane:

K = 11.6

The following examples are provided for calculating NO_x emissions on a mass basis, given the fuel type and NO_x emission level, in ppmv, dry (ppmvd), and corrected to 15 percent O_2.

Example 1. Natural gas fuel

Gas turbine:
Solar Centaur 'H'
Power output:
4,040 kW
Heat rate:
12,200 Btu/kW-hr
NO_x emissions:
105 ppmvd, corrected to 15 percent O_2
Fuel:

Natural gas

- lower heating value = 20,610 Btu/lb

- K = 12.1

Fuel flow:

$$4{,}040 \text{ kW} \times \frac{12{,}200 \text{ Btu}}{\text{kW-hr}} \times \frac{1 \text{ lb fuel}}{20{,}610 \text{ Btu}} = 2{,}391 \text{ lb/hr}$$

From Equation 1:

$$\frac{105}{EINO_x} = 12.1$$

NO_x emissions, lb/hr:

$$2{,}391 \frac{\text{lb fuel}}{\text{hr}} \times \frac{8.68 \text{ lb } NO_x}{1{,}000 \text{ lb fuel}} = 20.8 \frac{\text{lb } NO_x}{\text{hr}}$$

Example 2. Distillate oil fuel

Gas turbine:

General Electric LM2500

Power output:

22670 kW

Heat rate:

9296 Btu/kW-hr

No_x emissions: 345 ppmvd, corrected to 15 percent O_2

Fuel:

Distillate oil No. 2

-

lower heating value = 18,330 Btu/lb

- K = 13.2

Fuel flow:

$$22{,}670 \text{ kW} \times 9296 \frac{\text{Btu}}{\text{kW-hr}} \times \frac{1 \text{ lb fuel}}{18{,}330 \text{Btu}} = 11{,}500 \text{ lb/hr}$$

From Equation 1:

$$\frac{345}{EINO_x} = 13.2$$

NO_x emissions, lb/hr:

$$11{,}500 \frac{\text{lb fuel}}{\text{hr}} \times \frac{26.1 \text{ lb } NO_x}{1{,}000 \text{ lb fuel}} = 300 \frac{\text{lb } NO_x}{\text{hr}}$$

REFERENCES FOR APPENDIX A:

1. Letter and attachments from Lyon, T.F., General Electric Aircraft Engines, to Snyder, R.B., MRI. December 6, 1991. Calculation of NO_x emissions from gas turbines.

2. Letter and attachments from Hung, W.S., Solar Turbines, Inc., to Snyder, R.B., MRI. December 17, 1991. Calculation of NO_x emissions from gas turbines.

APPENDIX B. COST DATA AND METHODOLOGY USED TO PREPARE COST FIGURES PRESENTED IN CHAPTER 6

APPENDIX B. RAW COST DATA AND COST ALGORITHMS

The maintenance costs for water injection and several of the SCR costs presented in Chapter 5 are based on information from turbine manufacturers and other sources that required interpretation and analysis. Information about additional gas turbine maintenance costs associated with water injection is presented in Section B.1. Information on SCR capital costs, catalyst replacement and disposal costs, and maintenance costs is presented in Section B.2. References are listed in Section B.3.

B.1 WATER INJECTION MAINTENANCE COSTS

Information from each manufacturer and the applicable analysis procedures used to develop maintenance cost impacts for water injection are described in the following sections.

B.1.1 Solar

This manufacturer indicated that the annual maintenance cost for the Centaur is $16,000/year.[1] The cost for the Saturn was estimated to be $8,000.[2] This $8,000 cost was then prorated for operation at 1,000/hr/yr, and was multiplied by 1.3 to account for the additional maintenance required for oil fuel.

B.1.2 Allison

Maintenance costs for water injection were provided by a company that packages Allison gas turbines for stationary applications. This packager stated that for the 501 gas turbine model, a maintenance contract is available which covers all maintenance materials and labor costs associated with the turbine, including all scheduled and unscheduled activities. The cost of this contract for the 501 model is $0.0005 to $0.0010 per KW-hour (KWH) more for water injection than for a turbine not using water injection.[3] For an installation operating 8,000 hours per year at a base-rated output of 4,000 KW, and using an average cost of $0.00075 per KWH, the annual additional maintenance cost is $24,000. By the nature of the contract offered, this figure represents a worst case scenario and to some extent may exceed the actual incremental maintenance costs that would be expected for water injection for this turbine.

B.1.3 General Electric

General Electric (GE) offers both aero-derivative type (LM-series models) and heavy-duty type (MS-series models) gas turbines. For the aero-derivative turbines, GE states that the incremental maintenance cost associated with water injection is $3.50 per fired hour. This cost is used to calculate the maintenance cost for water injection for GE aeroderivative turbines. No figures were provided for steam injection and no maintenance cost was used for steam injection with these turbines.[4]

Water injection also impacts the maintenance costs for the heavy-duty MS-series models. Costs associated with more frequent maintenance intervals required for models using water injection have been calculated and summarized below. A GE representative stated that the primary components which must be repaired at each maintenance interval are the combustor liner and transition pieces.[5] Approximate costs to repair these pieces were provided by GE.[5] For this analysis, the maximum cost estimates were used to calculate annual costs to accommodate repairs that may be required periodically for injection nozzles, cross-fire tubes, and other miscellaneous hardware. According to GE, a rule of thumb is that if the repair cost exceeds 60 percent of the cost of a new part, the part is replaced.[5] The cost of a replacement part is therefore considered to be 1.67 times the maximum repair cost. If water purity requirements are met, there are no significant adverse impacts on maintenance requirements on other turbine components, and hot gas path inspections and major inspection schedules are not impacted.[5] Combustion repair schedules, material costs, and labor hours are shown in Table B-1. Scheduled maintenance intervals for models with water injection were provided in Reference 6. Corresponding maintenance intervals for models with steam injection were assumed to be the same as models with no wet injection; these scheduled maintenance intervals were provided in Reference 7. Using the information in Table B-1, the total annual cost is

calculated and shown in Table B-2 for three GE heavy-duty turbine models.

B.1.4 Asea Brown Boveri

This manufacturer states there are no maintenance impacts associated with water injection.[8]

B.2 SCR COSTS

The total capital investment, catalyst replacement, and maintenance costs are estimated based on information from the technical literature. The cost algorithms are described in the following sections.

B.2.1 Total Capital Investment

Total capital investment costs, which include purchased costs and installation costs, were available for SCR systems for combined cycle and cogeneration applications from five sources.[9-13] These costs were scaled to 1990 costs using the Chemical Engineering annual plant cost indexes and are applicable to SCR systems in which the catalyst was placed within the heat recovery steam generator (HRSG). In addition, estimated capital investment costs were available from one source for SCR systems in which a high temperature zeolite catalyst is installed upstream of the HRSG.[14] Both the original data and the scaled costs are presented in Table B-3. The scaled costs were plotted against the turbine size and this plot is shown in Figure B-1. A linear regression analysis was performed to determine the equation for the line that best fits the data. This equation was used to estimate the total capital investment for SCR for the model plants and was extrapolated to estimate the costs for model plants larger than 90 MW.

B.2.2 Maintenance Costs

Maintenance costs for SCR controls were obtained from four literature sources, although 6 of the 14 points were obtained from one article.[9,11-13] These costs were scaled to 1990 costs assuming an inflation rate of five percent per year. All of the data are for turbines that use natural gas fuel. Because there are no data to quantify differences in SCR maintenance costs for oil-fired applications, the available data for operation on

natural gas were used for both fuels. Both the original data and the scaled costs are presented in Table B-4. The scaled costs were plotted versus the turbine size in Figure B-2. The equation for the line through the data was determined by linear regression, and it was used to estimate the maintenance costs for the model plants.

B.2.3 Catalyst Replacement Costs

Catalyst replacement costs were obtained from three articles for nine gas turbine installations.[9,11,13] Combined catalyst replacement and disposal costs were obtained for another six gas turbine installations from one article.[12] The disposal costs for these six gas turbine installations were estimated based on estimated catalyst volumes and a unit disposal cost of $\$15/ft^3$, given in Reference 15.

The catalyst volumes were estimated assuming there is a direct relationship between the volume and the turbine size; the catalyst volume stated in Reference 16 for one 83 MW turbine is 175 m^3. The resulting disposal costs for these six facilities were subtracted from the combined replacement and disposal costs to estimate the replacement-only costs. All of the replacement costs were scaled to 1990 costs assuming an inflation rate of 5 percent per year. The original data and the scaled costs are presented in Table B-5, and the scaled replacement costs were also plotted versus the turbine size in Figure B-3. Linear regression was used to determine the equation for the line through the data. This equation was used to estimate the catalyst replacement costs for the model plants.

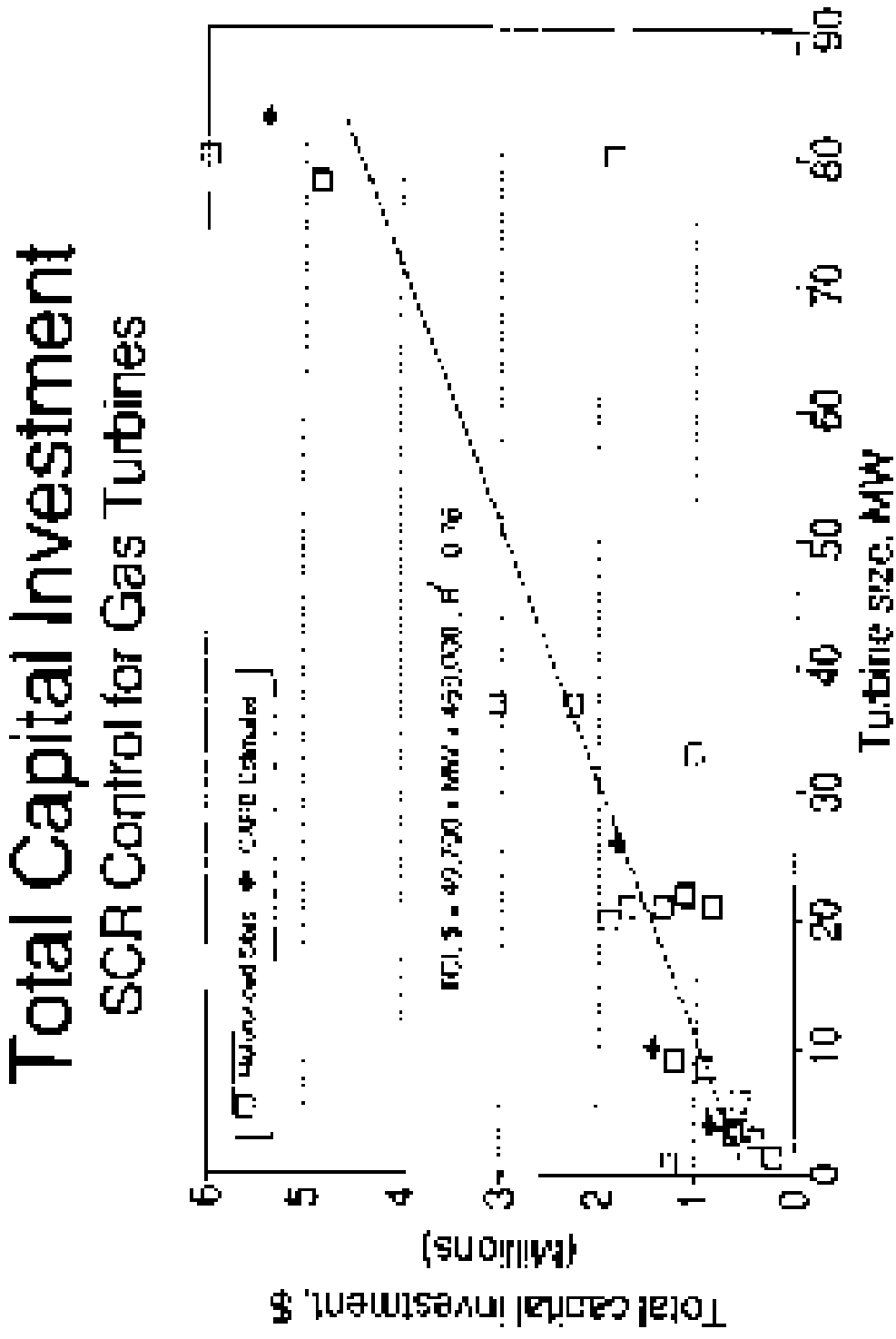


Figure B-1. Total Capital Investment for SCR Control of NO_x Emissions from Gas Turbines

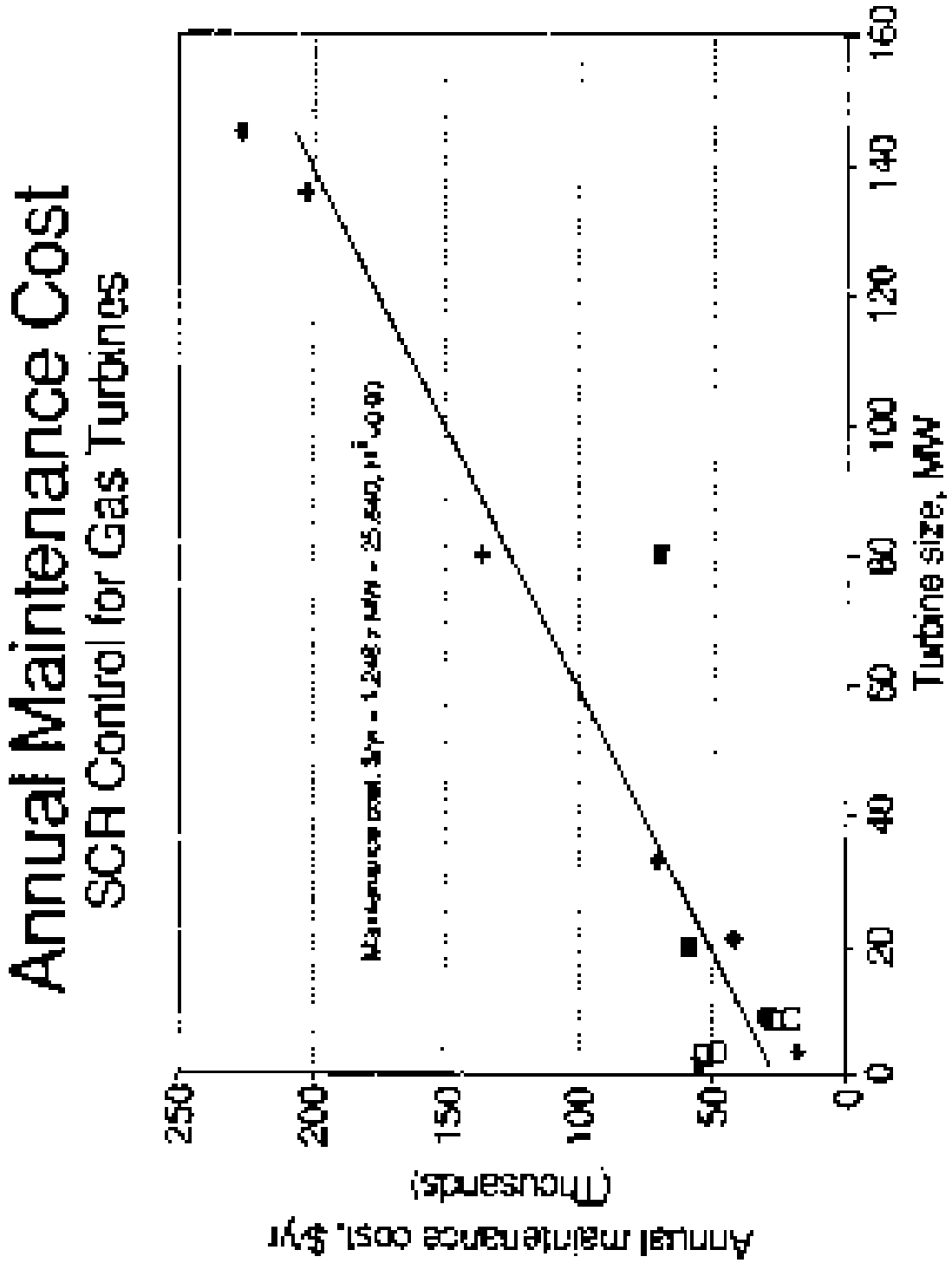


Figure B-2. Annual Maintenance Cost for SCR Control of NO_x Emissions from Gas Turbines

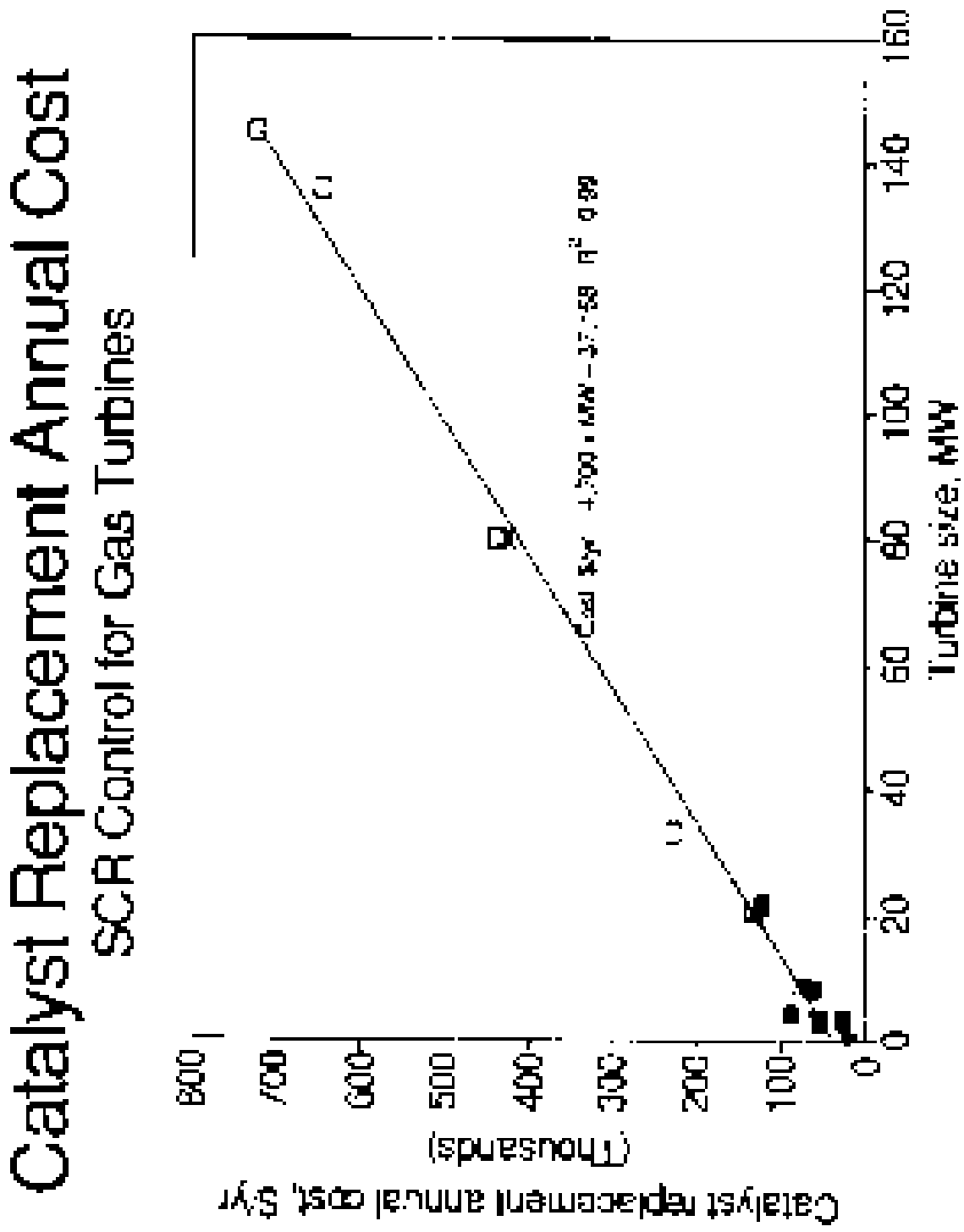


Figure B-3. Catalyst Replacement Annual Cost for SCR Control of Gas Turbines

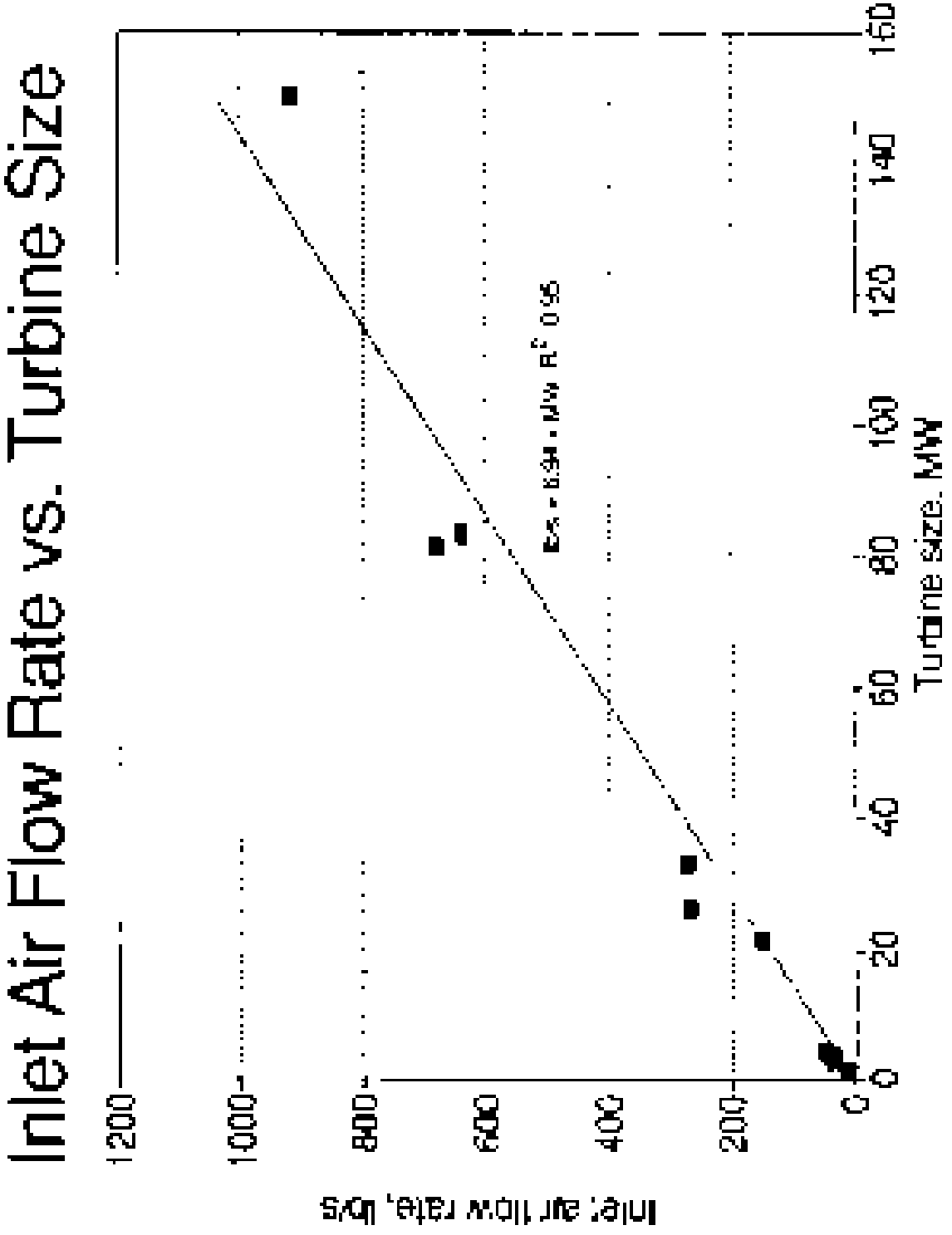


Figure B-4. Inlet Air Flow Rate for Gas Turbines

TABLE B-1. COMBUSTOR REPAIR INTERVALS, HOURS, AND MATERIAL COST

Gas turbine	Repair interval, hr		Replacement interval, hr		Repair cost, $[d]	Replacement cost, $[d]	Item	Labor hours [a]
	Dry	Wet[b]	Dry[a]	Wet[c]				
MS5001P	12,000	6,000	48,000	24,000	10,000-15,000 15,000-20,000	25,000 42,000	Liners Transition pieces	160
MS7001E	8,000	6,500	48,000	39,000	15,000-30,000 30,000-50,000	50,000 83,000	Liners Transition pieces	576
MS9001E	8,000	6,500	48,000	39,000	31,000-62,000 62,000-124,000	103,000 206,000	Liners Transition pieces	624

[a]Reference 7.
[b]Reference 6.
[c]Scaled from Dry Repair/Replace intervals found in Reference 9.
[d]Reference 5.

TABLE B-2. ANNUAL COST OF ADDITIONAL MAINTENANCE REQUIRED FOR WATER INJECTION

	Number of inspections over 15 years						Material costs		Labor, each inspection		Total added cost 15 years	Total added annual cost
	Dry		Wet		Added number for wet							
GT Model	Inspection	Replacement	Inspection	Replacement	Inspection	Replacement	Inspection	Replacement	Hours	Cost		
MS5001P [a]												
Combustor liners	8	2	15	5	7	3	15,000	25,000			18,000	
Transition pieces	8	2	15	5	7	3	20,000	42,000	160	4,998	315,980	
											495,980	33,065
MS7001E [e]												
Combustor liners	12	3	15	3.5	3	0.5	30,000	50,000			115,000	
Transition pieces	13	2	15.5	3	2.5	1	50,000	83,000	576	17,994	270,979	
											385,979	25,732
MS9001E [e]												
Combustor liners	12	3	15	3.5	3	0.5	62,000	103,000			237,500	
Transition pieces	13	2	15.5	3	2.5	1	124,000	206,000	624	19,494	584,229	
											821,729	54,782

[a]Based on $31.24/hr. Since parts are normally removed and a spare set is installed at each inspection, the labor cost would be the same for either repair or replacement interval.

[b]Schedule assumes liners and transition pieces are replaced every fourth inspection interval.

[c](7 x $15,000) + (3 x $25,000) = $180,000.

[d](7 x $20,000) + (3 x $42,000) + ($4,998 x 10) = $315,980.

[e]Schedule assumes liners are replaced every fifth interval and transition pieces every sixth interval.

TABLE B-3. TOTAL CAPITAL INVESTMENT FOR SCR TO CONTROL NO_x EMISSIONS FROM GAS TURBINES

Gas turbine size, MW	SCR capital cost[a]			Scaling factor[c]	1990 SCR capital cost, $
	$	Year	Ref[b]		
1.1	1,250,000	1989	9	357.6/355.4	1,260,000
1.5	180,000	1986	10	357.6/318.4	202,000
3	320,000	1986	10	357.6/318.4	359,000
3.2	600,000	1989	11	357.6/3.554	604,000
3.7	477,000	1988	12	357.6/342.5	498,000
3.7	579,000	1989	11	357.6/355.4	583,000
4	839,000	1991	14	1.0	839,000
4.5	750,000	1988	11	357.6/342.5	783,000
6	480,000	1986	10	357.6/318.4	539,000
8.4	800,000	1986	11	357.6/318.4	898,000
9	1,100,000	1987	13	357.6/323.8	1,210,000
10	1,431,000	1991	14	1.0	1,431,000
20	1,700,000	1987	13	357.6/323.8	1,880,000
21	798,000	1988	12	357.6/342.5	833,000
21	1,500,000	1986	10	357.6/318.4	1,680,000
21	1,200,000	1986	10	357.6/318.4	1,350,000
22	1,000,000	1987	11	357.6/323.8	1,100,000
26	1,800,000	1991	14	1.0	1,800,000
33	990,000	1988	12	357.6/342.5	1,030,000
37	2,000,000	1986	11	357.6/318.4	2,250,000
37	2,700,000	1986	10	357.6/318.4	3,030,000
78	4,300,000	1986	10	357.6/318.4	4,830,000
80	5,400,000	1987	13	357.6/323.8	5,960,000
80	1,760,000	1988	12	357.6/342.5	1,840,000
83	5,360,000	1991	14	1.0	5,360,000

continued

TABLE B-3. (Continued)

[a]Total capital costs were provided by several sources, but it is not clear that they are on the same basis. For example, it is likely that the type of catalyst varies and the target NO_x reduction efficiency may also vary. In addition, some estimates may not include costs for emission monitors; auxiliary equipment like the ammonia storage, handling, and transfer system; taxes and freight; or installation.

[b]Reference 12 also provided costs for SCR used with 136 MW and 145 MW turbines. All of the costs for this reference are lower than the costs from other sources, and the differential increases as the turbine size increases. Because there are no costs from other sources for such large turbines, these two data points would exert undue influence on the analysis; therefore, they have been excluded. Costs for large model plants were estimated by extrapolating with the equation determined by linear regression through the data for turbines with capacities less than 90 MW (see Figure B-1).

[c]Costs for years prior to 1990 are adjusted to 1990 dollars based on the annual CE plant cost indexes. Costs estimated in 1991 dollars were not adjusted.

TABLE B-4. MAINTENANCE COSTS FOR SCR

Gas turbine size, MW	SCR maintenance cost[a]			Scaling factor[b]	1990 SCR maintenance cost, $
	$/yr	Year	Ref		
1.1	52,200	1989	9	1.050	54,800
3.2	50,000	1989	11	1.050	52,500
3.7	43,000	1988	11	1.103	47,400
3.7	15,500	1988	12	1.103	17,100
8.4	22,000	1986	11	1.216	26,700
8.9	18,000	1988	11	1.103	19,800
9	25,000	1987	13	1.158	28,900
20	50,000	1987	13	1.158	57,900
21	37,900	1988	12	1.103	41,800
33	63,700	1988	12	1.103	70,200
80	124,000	1988	12	1.103	137,000
80	60,000	1987	13	1.158	69,500
136	184,000	1988	12	1.103	203,000
145	205,000	1988	12	1.103	226,000

[a]All of the maintenance costs are for turbines that are fired with natural gas. Although sulfur in diesel fuel can cause maintenance problems, there are no data to quantify the impact. Therefore, the maintenance costs presented in this table were used for both natural gas and diesel fuel applications.
[b]Scaling factors are based on an estimated inflation rate of 5 percent per year.

TABLE B-5. CATALYST REPLACEMENT AND DISPOSAL COSTS

Gas turbine size, MW	Catalyst replacement cost [a]						Catalyst disposal cost			Catalyst replacement and disposal annual cost, $/yr
	$	Year	Ref.	Scaling factor[b]	1990 catalyst cost, $	Annual cost, $/yr[c]	Catalyst volume, m^3	1990 cost, $[e]	Annual cost, $/yr[c]	
1.1	74,600	1989	9	1.050	78,300	20,700	2.32	1,230	324	21,000
3.2	200,000	1989	11	1.050	210,000	55,400	6.75	3,570	940	56,300
3.7		1988	12	1.103	215,000	56,600	7.80	4,130	1,090	57,700
3.7	100,000	1988	11	1.103	110,000	29,000	7.80	4,130	1,090	30,100
4.5	300,000	1988	11	1.103	331,000	87,300	9.49	5,030	1,330	89,000
8.4	200,000	1986	11	1.216	243,000	64,100	17.7	9,380	2,470	67,000
9	255,000	1987	13	1.158	295,000	77,800	19.0	10,100	2,660	80,000
20	434,000	1987	13	1.158	502,000	132,000	42.2	22,300	5,880	138,000
21		1988	12	1.103	512,000	135,000	44.3	23,500	6,200	141,000
22	400,000	1987	11	1.158	463,000	122,000	46.4	24,600	6,490	128,000
33		1988	12	1.103	864,000	228,000	69.6	36,900	9,700	238,000
80		1988	12	1.103	1,660,000	437,000	169	89,300	23,600	461,000
80	1,400,000	1987	13	1.158	1,620,000	427,000	169	89,300	23,600	451,000
136		1988	12	1.103	2,450,000	645,000	287	152,000	40,100	685,000
145		1988	12	1.103	2,740,000	723,000	306	162,000	42,700	766,000

[a]Reference 12 provided only combined catalyst replacement and disposal costs.

[b]Scaling factors are based on an inflation rate of 5 percent per year.

[c]Annual costs are based on the assumption that the catalyst will be replaced every 5 years. Therefore, the capital recovery factor is 0.2638, assuming an annual interest rate of 10 percent.

[d]In one SCR application, 175 m^3 of catalyst is used with an 83 MW turbine. If the space velocity is the same for any size SCR (assuming the same catalyst), then there is a direct relationship between the amount of catalyst and the exhaust gas flow rate. The exhaust gas flow rate was calculated as equal to the inlet air flow rate, and as Figure B-4 shows, there is nearly a direct relationship between the inlet airflow rate and turbine capacity. Therefore, the catalyst volume for the turbines in this table were estimated assuming there is a direct relationship between the catalyst volume and the turbine output.

[e]Disposal costs are estimated based on a unit cost of $15/$ft^3$.

B.3 REFERENCES FOR APPENDIX B

I. Letter and attachments from Swingle, R., Solar Turbines Incorporated, to Snyder, R., MRI. May 21, 1991. Maintenance considerations for gas turbines.

II. Letter and attachments from Swingle, R., Solar Turbines Incorporated, to Neuffer, W.J., EPA/ISB. August 20, 1991. Review of draft gas turbine ACT document.

III. Letter and attachments from Lock, D., U.S. Turbine Corporation, to Neuffer, W.J., U.S EPA/ISB. September 17, 1991. Review of draft gas turbine ACT document.

IV. Letter and attachments from Sailer, E.D., General Electric Marine and Industrial Engines, to Neuffer, W.J., EPA/ISB. August 29, 1991. Review of draft gas turbine ACT document.

V. Telecon. Snyder, R., MRI, with Pasquarelli, L., General Electric Company. April 26, 1991. Maintenance costs for gas turbines.

VI. Letter and attachment from Schorr, M., General Electric Company, to Snyder, R., MRI. April 1, 1991. Response to gas turbine questionnaire.

VII. Walsh, E. Gas Turbine Operating and Maintenance Considerations. General Electric Company. Schenectady, NY. Presented at the 33rd GE Turbine State-of-the-Art Technology Seminar for Industrial, Cogeneration and Independent Power Turbine Users. September, 1989. 20 pp.

VIII. Letter and attachments from Gurmani, A., Asea Brown Boveri, to Snyder, R., MRI. May 30, 1991. Response to gas turbine questionnaire.

IX. Permit application processing and calculations by South Coast Air Quality Management District for proposed SCR control of gas turbine at Saint John's Hospital and Health Center, Santa Monica, California. May 23, 1989.

X. Hull, R., C. Urban, R. Thring, S. Ariga, M. Ingalls, and G. O'Neal. NO_x Control Technology Data Base for Gas-Fueled Prime Movers, Phase I. Prepared by Southwest Research Institute for Gas Research Institute. April 1988.

XI. Shareef, G., and D. Stone. Evaluation of SCR NO_x Controls for Small Natural Gas-Fueled Prime Movers. Phase I. Prepared by Radian Corporation for Gas Research Institute. July 1990.

XII. Sidebotham, G., and R. Williams. Technology of NO_x Control for Stationary Gas Turbines. Center for Environmental Studies. Princeton University. January 1989.

XIII. Prosl, T., DuPont,and Scrivner, G., Dow. Technical Arguments and Economic Impact of SCR's Use for NO_x Reduction of Combustion Turbine for Cogeneration. Paper presented at EPA Region 6 meeting concerning NO_x abatement of Combustion Turbines. December 17, 1987.

XIV. State of California Air Resources Board. Draft Proposed Determination of Reasonably Available Control Technology And Best Available Retrofit Technology for Stationary Gas Turbines. August, 1991. Appendix C.

XV. Letter and attachments from Henegan, D., Norton Company, to Snyder, R., MRI. March 28, 1991. Response to SCR questionnaire.

XVI. Schorr, M. NO_x Control for Gas Turbines: Regulations and Technology. General Electric Company. Schenectady, New York. Paper presented at the Council of Industrial Boiler Owners NO_x Control IV Conference. Concord, California. February 11-12, 1991. 11 pp.

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation
DIVISION OF AIR QUALITY
Director's Office
[illegible]

CERTIFIED MAIL: 7017 3040 0000 4359 5219
Return Receipt Requested

September 13, 2018

Naomi Knight, Environmental Officer
Golden Valley Electric Association
PO Box 71249
Fairbanks, AK 99707-1249

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum from Golden Valley Electric Association (GVEA) for the North Pole Power Plant and Zehnder Facility by November 1, 2018

Dear Ms. Knight:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that GVEA North Pole and Zehnder and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to a Serious Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measure (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as GVEA North Pole and Zehnder. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analyses are a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an email to Ms. Naomi Knight at GVEA on May 11, 2017 notifying her of the reclassification

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 [illegible]

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-09-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(a)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.

[3] https://www.gpo.gov/fdsys/pkg/FR-2016-09-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.

to Serious and included a request for the BACT analysis to be completed by August 8, 2017. The BACT analyses from GVEA North Pole and Zehnder, which included emission units found in Operating Permits AQ0110TVP03 and AQ0109TVP03, were submitted by email to the Department on August 30, 2017.

On March 22, 2018, ADEC released a preliminary draft of the BACT determination for GVEA for public discussion on its website at: http://dec.alaska.gov/air/anpms/comm/comm_fbks.htm. As indicated in the release, this document is a work in progress. ADEC received additional information from the EPA on the preliminary draft BACT determination and expects to make changes to the determination based upon this input. Therefore, ADEC is requesting additional information from GVEA to assist it in making a legally and practicably enforceable BACT determination for the source.

If ADEC does not receive a response to this information request by November 1, 2018, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facility's infrastructure and without additional information, may select a more stringent BACT for your facility in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public review along with any precursor demonstrations and BACM analyses before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes final BACT determinations for GVEA North Pole and Zehnder, it must include the determinations in Alaska's Serious SIP that then ultimately requires approval by EPA.[4] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented prior to June 9, 2021 - 4 years after reclassification.[5]

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM) consideration. MSMs will be a required element of the state implementation plan if the State applies for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

ADEC appreciates the cooperation that we've received from GVEA. ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

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[4] https://www.gpo.gov/fdsys/pkg/CFR-2013-title42-vol1/pdf/CFR-2013-title42-vol1-sec51-165.pdf
[5] 40 CFR 51.1010(a)

Sincerely,

Denise Koch, Director
Division of Air Quality

Enclosures:

September 10, 2018	ADEC Request for Additional Information for North Pole and Zehnder Facilities BACT Analyses
May 21, 2018	EPA Comments on ADEC Preliminary Draft Serious SIP Development Materials for the Fairbanks Serious PM-2.5 nonattainment Area
November 16, 2017	ADEC Request for Additional Information for North Pole and Zehnder BACT Analyses;
November 15, 2017	EPA GVEA BACT Analysis Review Comments
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for GVEA North Pole and Zehnder

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality
Jim Plosay, ADEC/ Air Quality
Aaron Simpson, ADEC/Air Quality
Naomi Knight/GVEA
Tim Hamlin, EPA Region 10
Dan Brown, EPA Region 10
Zach Hedgpeth, EPA Region 10

ADEC Request for Additional Information
Golden Valley Electric Association – North Pole and Zehnder Facilities
BACT Analysis Review
August 2017

September 10, 2018

Please address the following comments by providing the additional information identified by November 1, 2018. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public review. In order to provide this additional review opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public review period or based upon the new information provided in response to this information request.

This document does not represent a final BACT determination by ADEC. Please contact Aaron Simpson at aaron.simpson@alaska.gov with any questions regarding ADEC's comments.

1. Equipment Life – Page 31 of the North Pole analysis and Page 27 of the Zehnder analysis state "Because of the harsh climate, equipment in this far north location experiences more wear and tear than equipment in moderate climates. On this basis, a ten year return on the [water injection and] SCR system is assumed to be reasonable." This same assumption is made for the other control devices. ADEC identified that the EPA Air Pollution Control Cost Manual[1] uses a hypothetical example that assumes the control equipment has a useful life of ten years. However the cost analyses must use a reasonable estimate of the actual life of the control equipment for each control technology. In order to use an equipment life that is shorter than 30 years, evidence must be provided to support the claim that 10 years is a reasonable timeframe for equipment life. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as turbines.

2. BACT limits – BACT limits by definition, are numerical emission limits. However regulation allows a design, equipment, or work/operational practices if technological or economic limitations make a measurement methodology infeasible. Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for pollutant for each emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. Measures to minimize the occurrence of these periods, or to minimize emissions during these periods are control options. Combinations of steady-state control options and SSM control options can be combined to create distinct control strategies. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

[1] U.S. EPA OAQPS Air Pollution Control Cost Manual, 6th Edition [EPA/452/B-02-001]

3. Cost Analyses – Page 44 of the North Pole analysis indicates that EUs 1 and 2 have historically low run hours. Page 34 of the Zehnder analysis state that "GVEA believes that an economic analysis based on the actual emissions and operations of these turbines is more relevant for purposes of determining viable ways to reduce PM2.5 ambient concentrations in the Fairbanks area." However, all BACT cost effectiveness calculations must be based upon the potential to emit, and not on historic operation. Please update the cost analyses using the unrestricted potential to emit for each of the emissions units or propose operational limits (including control efficiencies associated with limited operation). Additionally, see Comments 4, 5, and 6 for additional information related to retrofit costs, baseline emissions, and factor of safety.
4. Retrofit Costs – EPA's Control Cost Manual indicates that study-level cost estimates (± 30 percent) should not include a retrofit factor greater than 30 percent, so detailed cost estimates (± 5 percent) are required for higher factors. High retrofit cost factors (50 percent or more) may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement). Provide detailed cost analyses and justification for any difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analyses.
5. Baseline Emissions – Include the baseline emissions for all emission units included in the analyses. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). NSPS and NESHAP requirements are not considered in calculating the baseline emissions. The baseline is usually the legal limit that would exist, but for the BACT determination. Baseline takes into account the effect of equipment that is part of the design of the unit (e.g., water injection and low NOx burners) because they are considered integral components to the unit's design. If the uncontrolled emission rate is 'soft,' run the cost effectiveness calculations using two or three different baselines.
6. Factor of Safety – If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.
7. Good Combustion Practices –For each emission unit type (oil fuel-fired turbines, combined cycle turbines, emergency generator engines, and boilers) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices. Include any work or operational practices that will be implemented and describe how continuous compliance with good combustion practices will be achieved.
8. Control Technology Availability – For the North Pole Facility, include Flue Gas Recirculation in the review of NOx control technologies for diesel-fired boilers. Rank the control technologies by efficiency (specify % control). Select the best performing control technology as BACT or provide specific energy, environmental, and economic impacts and other costs justification for why each better performing control technology was not selected instead of good combustion practices. Provide a numerical NOx emission limit for the diesel-fired boilers or identify the work or operational practices that will be utilized to ensure compliance with proposed limits.
9. Alternative Fuel Costs – Please provide a cost analysis for SO_2 emissions reductions for switching from current No. 2 diesel fuel to low sulfur diesel with a sulfur fuel content of 0.05 percent by weight. Also provide a cost analysis for a switch from No. 2 diesel fuel to No. 1 diesel fuel.

10. Interest Rate – All cost analyses must use the current bank prime interest rate. This can be found online at https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table). Please revise the cost analyses as appropriate.
11. Conversion to Natural Gas – For any emission units capable of converting to natural gas combustion (with the requisite changes to the burners, etc.), evaluate the commercial availability of converting to natural gas. For example, GVEA has stated the combustion turbines at its North Pole Expansion Power Plant have the ability to burn natural gas, and the IGU has indicated the intent to expand the supply of natural gas to Fairbanks and North Pole.

Attachment: EPA comments on ADEC Preliminary Draft Serious SIP Development materials for the Fairbanks serious $PM_{2.5}$ nonattainment area

General

The attached comments are intended to provide guidance on the preliminary drafts of SIP documents in development by ADEC. We expect that there will be further opportunities to review the more complete versions of the drafts and intend to provide more detailed comments at that point

1. Statutory Requirements - This preliminary draft does not address all statutory requirements laid out in Title I, Part D of the Clean Air Act or 40 C.F.R. Part 51, Subpart Z. The submitted Serious Area SIP will need to address all statutory and regulatory requirements as identified in Title I, Part D of the Clean Air Act, 40 C.F.R. Part 51, Subpart Z, the August 24, 2016 $PM_{2.5}$ SIP Requirements Rules (81 FR 58010, also referred to at the $PM_{2.5}$ Implementation Rule), and any associated guidance.

   In the preliminary drafts, notable missing elements included: Reasonable Further Progress, Quantitative Milestones, and Conformity. This is not an exhaustive list of required elements.

   The NNSR program is a required element for the serious area SIP. We understand ADEC recently adopted rule changes to address the nonattainment new source review element of the Serious SIP, and that ADEC plans to submit them to the EPA separately in October 2018. Thank you for your work on this important plan element.

2. Extension Request - This preliminary draft does not address the decision to request an attainment date extension and the associated impracticability demonstration. On September 15, 2017, ADEC sent a letter notifying the EPA that it intends to apply for an extension of the attainment date for the Fairbanks $PM_{2.5}$ Serious nonattainment area. The Serious Area SIP submitted to EPA will need to include both an extension request and an impracticability demonstration that meet the requirements of Clean Air Act section 188(e). In order to process an extension request, the EPA requests timely submittal of your Serious Area SIP to allow for sufficient time to review and take action prior to the current December 2019 attainment date, so as to allow, if approvable, the extension of the attainment date as requested/appropriate. For additional guidance, please refer to 81 FR 58096.

3. Split Request - We support the ADEC and the FNSB's decision to suspend their request to the EPA to split the nonattainment area. We support the effort to site a monitor in the Fairbanks area that is more representative of neighborhood conditions and thus more protective of community health. This would provide additional information on progress towards achieving clean air throughout the nonattainment area.

4. BACM (and BACT), and MSM - Best Available Control Measures (including Best Available Control Technologies) and Most Stringent Measures are evaluative processes inclusive of steps to identify, adopt, and implement control measures. Their definitions are found in 51.1000, 51.1010(a).

All source categories, point sources – area sources – on-road sources – non-road sources, need to be evaluated for BACM/BACT and MSM. De minimis or minimal contribution are not an allowable rationale for not evaluating or selecting a control measure or technology.

The process for identifying and adopting MSM is separate from, yet builds upon, the process of selecting BACM. Given that Alaska is intent on applying for an extension to the attainment date, Alaska must identify BACM and MSM for all source categories. These processes are described in 51.1010(a) and 51.1010(b) and in the $PM_{2.5}$ Implementation Rule preamble at 81 FR 58080 and 58096. We further discuss this process in the "BACM (and BACT), MSM" section that starts on page 3 below.

5. Resources and Implementation - The serious area $PM_{2.5}$ attainment plan will be best able to achieves its objectives when all components of the SIP, both the ADEC statewide and FNSB local measures, are sufficiently funded and fully implemented.

6. Use of Consultants- For the purpose of clarity, it will be important to identify that while contractors are providing support to ADEC, all analyses are the responsibility of the State.

Emissions Inventory

1. Extension Request Emission Inventories - Emissions inventories associated with the attainment date extension request will need to be developed and submitted. Table 1 of the Emissions Inventory document is one example where the submittal will need to include the additional emissions inventories, including RFP inventories, extension year inventories for planning and modeling, and attainment year planning and modeling inventories, associated with the attainment date extension request.

2. Modeling Requirements - Related to emissions inventory requirements, the serious area SIP will need to model and inventory 2023 and 2024, at minimum. We recommend starting at 2024 and modeling earlier and earlier until there is a year where attainment is not possible. That would satisfy the requirement that attainment be reached as soon as practicable.

3. Condensable Emissions - All emissions inventories and any associated planning, such as Reasonable Further Progress schedules, need to include condensable emissions as a separate column or line item, where available. Where condensable emissions are not available separately, provide condensable emissions as included (and noted as such) in the total number. The following are examples of where this would need to be incorporated in to the Emissions Inventory document:
    a. Page 20, paragraph 5 (or 2nd from the bottom).
    b. Page 34, Table 8. Include templates.

Precursor Demonstration

1. Ammonia Precursor Demonstration - The draft Concepts and Approaches document, Table 4 on page 9, states that a precursor demonstration was completed for ammonia and that the result was "Not significant for either point sources or comprehensively." The Precursor Demonstration chapter does not include an analysis for ammonia. Please include the precursor demonstration for ammonia in the Serious Plan or amend this table.

2. Sulfur Dioxide Precursor Description - The draft Concepts and Approaches document, Table 4 on page 9, states that sulfur dioxide was found to be significant. All precursors are presumptively considered significant by default and the precursor demonstration can only show that controls on a precursor are not required for attainment. Suggested language is, "No precursor demonstration possible."

BACM (and BACT), MSM

Overall

The EPA appreciates ADECs efforts to identify and evaluate BACM for eventual incorporation into the Serious Area SIP. The documents clearly display significant effort on the part of the state and are a good first step in the SIP development process. In particular, we are supportive of ADECs efforts to evaluate BACT for the major stationary sources in the nonattainment area, as control of these sources is required by the CAA and $PM_{2.5}$ SIP Requirements Rule.

1. BACM/BACT and MSM: Separate Analyses - The "Possible Concepts and Potential Approaches" document appears to conflate the terms BACM/BACT and MSM, as well as, the analyses for determining BACM/BACT and MSM. BACM and MSM have separate definitions in 40 CFR 51.1000. By extension, the processes for selecting BACM and MSM are laid out separately in the $PM_{2.5}$ SIP Requirements Rule (compare 40 CFR 51.1010(a) for BACM and 40 CFR 51.1010(b) for MSM). Accordingly, the serious area SIP submission will need to have both a BACM/BACT analysis and an MSM analysis. We believe that there is flexibility in how these analyses can be presented, so long as the submission clearly satisfies the requirements of both evaluations, methodologies, and findings.

2. Selection of Measures and Technologies - The CAA and the $PM_{2.5}$ SIP Requirements Rule requires that ***all*** available control measures and technologies that meet the BACM (including BACT) and MSM criteria need to be implemented. All source categories need to be evaluated including: point sources (including non-major sources), area sources, on-road sources, and non-road sources.

3. Technological Feasibility - All available control measures and technologies include those that have been implemented in nonattainment areas or attainment areas, or those potential measures and technologies that are available or new but not yet implemented. Similarly, Alaska may not automatically eliminate a particular control measure because other sources or nonattainment areas have not implemented the measure. The regulations do not have a quantitative limit on number of controls that should be implemented.

For technological feasibility, a state may consider factors including local circumstances, the condition and extent of needed infrastructure, or population size or workforce type and habits, which may prohibit certain potential control measures from being implementable. However, in the instance where a given control measure has been applied in another NAAQS nonattainment area, the state will need to provide a detailed justification for rejecting any potential BACM or MSM measure as technologically infeasible (81 FR 58085).

A Borough referendum prohibiting regulation of home heating would not be an acceptable consideration to render potential measures technologically infeasible. The State would be responsible for implementing the regulations in the case that the Borough was not able. We believe that the most efficient path to clean air in the Borough is through a local, community effort.

4. Economic Feasibility - The BACM (including BACT) and MSM analyses need to identify the basis for determining economic feasibility for both the BACM and MSM analyses. In general, the $PM_{2.5}$ SIP Requirements Rule requires the state apply more stringent criteria for determining the feasibility of potential MSM than that used to determine the feasibility of BACM and BACT, including consideration of higher cost/ton values as cost effective.

5. Timing - The evaluations will need to identify the time for selection, adoption, and implementation for all measures. BACT must be selected, adopted, and implemented no later than 4 years after reclassification (June 2021). MSM must be selected, adopted, and implemented no later than 1 year prior to the potentially extended attainment date (December 2023 at latest). The RFP section of the serious area plan will need to identify the BACM and MSM control measures, their time of implementation, and the time(s) of expected emissions reductions. Timing delays in selection, adoption, implementation are not considered for BACM and MSM.

   As mentioned in the comment above in the "General" comment section, there are three criteria distinguishing between BACM and MSM, not one.

BACM - General

1. BACM definition, evaluations - The definition of BACM at 40 CFR 51.1000 describes BACM as any measure "that generally can achieve greater permanent and enforceable emissions reductions in direct $PM_{2.5}$ and/or $PM_{2.5}$ plan precursors from sources in the area than can be achieved through the implementation of RACM on the same sources." We believe that potential measures that are no more stringent than existing measures already implemented in FNSB, those that do not provide additional direct $PM_{2.5}$ and/or $PM_{2.5}$ precursors emissions reductions, do not meet the definition of BACM. These would need to be evaluated in the BACM and MSM analysis.

   For measures that are currently being implemented in Fairbanks that provide equivalent or more stringent control, we recommend identifying the ADEC or Borough implemented measure as part of the BACM control strategy. These implemented measures should be listed in their BACM findings at the end of the document. This comment applies to all of the

measures that were screened out from consideration due to not being more stringent than the already implemented measure.

The analyses for a number of measures (e.g., Measure 30, Distribution of Curtailment Program information at time of woodstove sale) conclude that the emission reductions would be insignificant and difficult to quantify and, therefore, the measure is not technologically feasible. These measures may be technologically feasible. However, if existing measures constitute a higher level of control or if implementation of the measures is economically infeasible those would be valid conclusions if properly documented. De minimis or minimal contribution is not a valid rationale for not considering or selecting a control measure or technology.

The conclusion "not eligible for consideration as BACM" is not valid as all assessments for BACM and MSM are part of the evaluation. More appropriate conclusions could include that existing measures qualify as BACM or MSM, or are more stringent. Additional conclusions could include that evaluated measures were not technologically feasible, economically feasible, or could not practically be adopted and implemented prior to the required timeframe for BACM or MSM.

2. BACM and MSM, Ammonia - In the Approaches and Concepts document, Table 5 references that there are no applicable control measures or technologies for the $PM_{2.5}$ precursor ammonia. No information to substantiate this claim are found in the preliminary draft documents. Unless NH_3 is demonstrated to be insignificant for this area, the serious area plan will need to include an evaluation of NH_3 and potential controls for all source categories including points sources.

3. Backsliding Potential - When benchmarking the BACM and MSM analyses for stringency, ensure that the evaluation is based on the measures approved into the current Moderate SIP. This will relate primarily to the current ADEC/FNSB curtailment program but also other related rules. Many wood smoke control measures are interrelated, and changes to those measures may affect determinations on stringency of directly related and indirectly related measures. Examples of this can be found in multiple measures including, but not limited to Measures 5, 7, and 16.

4. Transportation Control Measures - The Approaches and Concepts document, on Page 13, states that the MOVES2014 model does not estimate a PM benefit as a result of an I/M program, and therefore the I/M is not technologically feasible. This is not a valid conclusion given that the Fairbanks area operated an I/M program to reduce carbon monoxide and the Utah Cache Valley nonattainment areas has an I/M program for VOC control. This measure will need to be evaluated. Referring to the 110(l) analysis for the Fairbanks CO I/M program may provide insight into how to quantify the emissions associated with an I/M program.

With regard to control measures related to on-road sources, we have received inquiries from the community regarding idling vehicles and further evaluation emission benefits would be responsive to citizen concern and may provide additional air quality benefit.

BACM - Specific Measures

- Measure 16, page 34-35. Date certain Removal of Uncertified Devices. The "date certain" removal of uncertified woodstoves in Tacoma, Washington appears more stringent than the current Moderate SIP approved Fairbanks ordinance in terms of the regulation and in practice. While the current ordinance appears to provide similar protection during stage 1 alerts, this is dependent on 100% compliance and the curtailment program remaining in its current form. Removal of uncertified stoves guarantees reductions in emissions in the airshed during both the curtailment periods and throughout the heating season. The information provided does not support the conclusion that the Fairbanks controls provides equivalent or more stringent control. Date certain removal of uncertified wood stoves needs to be considered for the area.

  Measures R4, R9, and R12, page 64, 68 and 71. These measures do not reference the Puget Sound Clean Air Agency (Section 13.07) requirement for removal of all uncertified stoves by September 30, 2015. This is equivalent to having all solid fuel burning appliances be certified and would be more stringent than the current SIP approved rules in Fairbanks. We believe that these measures need to be evaluated in the BACM and MSM analyses.

  Measure R4 and R9, page 64 and 68. All Wood Stoves Must be Certified. These measure should be evaluated.

- Measure 19-20 and 25, page 36-38 and 39. Renewal and Inspection Requirements. ADEC has not adequately demonstrated their conclusion that Fairbanks has a more stringent measure than Missoula and San Joaquin. We believe that the renewal requirements and inspection/maintenance requirements associated with the Missoula alert permits and San Joaquin registrations allows the local air agency an opportunity to verify on a regular basis that the device operates properly over times. Wood burning appliances require regular maintenance in order to achieve the certified emissions ratings. The FNSB Stage 1 waivers do not have an expiration and do not have an inspection and maintenance component making it less stringent.

- Measure 31, page 43. While the Borough has SIP approved dry wood requirements that prohibit the burning of wet wood and moisture disclosure requirements by sellers, we believe that a measure limiting the sale of wet wood during the winter months should be further analyzed for BACM (and MSM) consideration.

- Measures 33, 35, 36, 37, 43. Multiple Measures identify that recreational fires have been exempted from existing regulations. Small unregulated recreational fires, bonfires, fire pits,

and warming fires have the potential to contribute emissions during a curtailment period. The FNSB and ADEC regulations should be re-evaluated for removing this exclusion.

- Measure 49, page 58. Ban on Coal Burning. We believe the regulations in Telluride are more stringent than in Fairbanks. Telluride prohibits coal burning all year whereas in Fairbanks an existing coal stove can burn when there is no curtailment which could contribute additional emissions to the airshed, especially during poor conditions when a curtailment may not have been called. We do not agree with the conclusion that the PM_{10} controls are ineligible for consideration for control of $PM_{2.5}$.

- Measure R20, page 76. Transportation Control Measures related to Vehicle Idling. We have received multiple inquiries regarding community interest in controlling emissions from idling vehicles. These types of control measures should be further evaluated in the BACM and MSM analyses.

- Measure 1, page 79-81. Surcharge on Solid Fuel Burning Appliances. For purposes of implementing an effective program to reduce $PM_{2.5}$ in the Borough we believe that a surcharge may be a helpful way to supplement limited funds. Implementation efforts within the nonattainment area could benefit from $24,000 of additional funding whether used for a code enforcer or other support of the wood smoke programs.

- Additional controls that should be further evaluated for BACM and MSM include:
    - Measure R1, page 63: Natural gas fired kiln or regional kiln.
    - Measure R12, page 71: Replace uncertified stoves in rental units.
    - Measure R17, page 75: Ban use of wood stoves
    - Measure R6, page 65: Remove Hydronic Heaters at Time of Home Sale & Date certain removal of Hydronic heaters. We suggest evaluating these measures at the state and local level.
    - Weatherization / heat retention programs should be evaluated. These should be evaluated for existing homes through energy audits and increasing insulation and energy efficiency. For new construction, building codes (Fairbanks Energy Code) should be evaluated with reference to the IECC Compliance Guide for Homes in Alaska http://insulationinstitute.org/wp-content/uploads/2015/12/AK_2009.pdf, and the DOE R-value recommendations, http://www.fairbanksalaska.us/wp-content/uploads/2011/07/ENERGY-CODE.pdf. (Note: More recent information may be available.)
    - Fuel oil boiler upgrades / operation & maintenance programs should be evaluated.

BACM - Ultra-Low Sulfur Fuel

1. Incomplete Analysis - The report findings provide analysis of the demand curve over a relatively short (12 month) time frame. This analysis appears to be based on a partial equilibrium model. This is a misleading time frame given the volatility of demand side fuel oil pricing. Also, in order to determine the equilibrium price, the analysis must also analyze

the supply curve. The report does not include information about the future supply side costs but needs to in order to make conclusions about the cost to the community of ultra-low sulfur heating oil.

2. Analysis of Increased Supply, Consumption - The report does not address future change in the market nor potential economies of scale to be achieved by an increase in ultra-low sulfur fuel consumption. Page 3 of the report identifies that, "the additional premium to purchase ULS over HS, decreased significantly since 2008-2010. It is likely that, this can be attributed to increased ULS capacity." We believe that the report should further explore the supply side costs.

3. Supply Cost Analysis - A supply side cost analysis is necessary to better understand the cost to the supplier to produce and provide ULS heating fuel. The BACM analysis must start with a transparent and detailed economic analysis of exclusively supplying ultra-low sulfur heating oil to the nonattainment area.

4. BACM Assessment - The current analysis does not provide information needed to assess BACM economic feasibility. The report should analyze the total cost to industry of delivering ultra-low sulfur heating oil to the entire community in terms of standard BACM metrics, $/ton.

BACT

General Comments

At this time, EPA is providing general comments based on review of the draft BACT analyses prepared by ADEC as well as addressing certain issues discussed in earlier BACT comments provided by EPA. Detailed comments regarding each individual analysis are not being provided at this time. While EPA appreciates the time and effort invested by ADEC staff in preparing the draft BACT analyses, the basic cost and technical feasibility information needed to form the basis for retrofit BACT analyses at the specific facilities has not been prepared. In other words, analyses which are adequate to guide decision making regarding control technology decisions for these rather complex retrofit projects cannot be prepared without site specific evaluation of capital control equipment purchase and installation costs, and site specific evaluation of retrofit considerations. EPA will conduct a thorough review of any future BACT or MSM analyses which are prepared based on adequate site specific information, and will provide detailed comments relative to each emission unit and pollutant at that time.

1. Level of Analysis – The analyses are presented as "preliminary BACT/MSM analyses" on the website, but the documents themselves are titled only as BACT analyses and the conclusions only reflect BACT. Additionally, the determinations may not be stringent enough to be considered BACT given that better performing SO_2 control technologies have not been adequately analyzed. These analyses cannot be considered to provide sufficient basis to support a selection of MSM.
2. Site-Specific Quotes Needed – The cost analyses, particularly for SO_2 control technologies, must be based on emission unit-specific quotes for capital equipment purchase and

installation costs at each facility. These are retrofit projects which must be considered individually in order to obtain reliable study/budget level (+/- 30%) cost estimates which are appropriate to use as the basis for decision making in determining BACT and potentially MSM. EPA believes that control decisions of this magnitude justify the relatively small expense of obtaining site-specific quotes.

3. SO_2 Control Technologies – The analyses must include evaluation of circulating dry scrubber (CDS) SO_2 control technology. This demonstrated technology can achieve SO_2 removal rates comparable to wet flue gas desulfurization (FGD) at lower capital and annual costs, and is more amenable to smaller units and retrofits. Modular units are available.
4. Control Equipment Lifetime – The analyses must use reasonable values for control equipment lifetime, according to the EPA control cost manual (EPA CCM). EPA believes that the following equipment lifetimes reflect reasonable assumptions for purposes of the cost analysis for each technology as stated in the EPA control cost manual and other EPA technical support documents. Use of shorter lifetimes for purposes of the cost analysis must include evidence to support the proposed shortened lifetime. One example where EPA agrees a shortened lifetime is appropriate would be where the subject emission unit has a federally enforceable shutdown date. Certain analyses submitted in the past have claimed shortened equipment lifetimes based on the harshness of the climate in Fairbanks. In order to use an equipment life that is shortened based on the harsh climate, evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers. Lacking adequate justification, all cost analyses must use the following values for control equipment lifetime:
    a. SCR, Wet FGD, DSI, CDS, SDA – 30 years
    b. SNCR – 20 years
5. Availability of Control Technologies – Technologically feasible control technologies may only be eliminated based on lack of availability if the analysis includes documented information from multiple control equipment vendors (who provide the technology in question) which confirms the technology cannot be available within the appropriate implementation timeline for the emission unit in question.
6. Assumptions and Supporting Documents – All documents cited in the analyses which form the basis for costs used and assumptions made in the analyses must be provided. Assumptions made in the analyses must be reasonable and appropriate for the control technologies included in the cost analysis.
7. Interest Rate – All cost analyses must use the current bank prime interest rate according to the revised EPA CCM. As of May 10, 2018, this rate is 4.75%. See https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table).
8. Space Constraints – In order to establish a control technology as not technologically feasible due to space constraints or other retrofit considerations, detailed site specific information must be submitted in order to establish the basis for such a determination, including detailed drawings, site plans and other information to substantiate the claim.
9. Retrofit Factors – All factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor or whether installation of a specific control technology is technologically infeasible. EPA Region 10

believes that installation factors which would complicate the retrofit installation of the control technology should be evaluated by a qualified control equipment vendor and be reflected in a site-specific capital equipment purchase and installation quote. Lacking site-specific cost information, all factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor. One example of the many retrofit considerations that must be evaluated is the footprint required for each control technology. A vendor providing a wet scrubber will be able to estimate the physical space required for the technology, and evaluate the existing process equipment configuration and available space at each subject facility. The determination of whether a specific control technology is feasible and what the costs will be may be different at each facility based on this and other factors. Site-specific evaluation of these factors must be conducted in order to provide a reasonable basis for decision making.

10. Control Efficiency – Cost effectiveness calculations for each control technology must be based on a reasonable and demonstrated high end control efficiency achievable by the technology in question at other emission units, or as stated in writing by a control equipment vendor. If a lower pollutant removal efficiency is used as the basis for the analysis, detailed technical justification must be provided. For example, the ability of SCR to achieve over 90% NO_X reduction is well established, yet the ADEC draft analyses assume only 80% control. Use of this lower control efficiency requires robust technical justification.
11. Condensable Particulate Matter – Although the existing control technology on the coal fired boilers may be evaluated as to whether it meets the requirement for BACT for particulate matter, baghouses primarily reduce emissions of filterable particulate matter rather than condensable PM. Given that all condensable PM emitted by the coal fired boilers would be classified as $PM_{2.5}$, the BACT analyses must include consideration of control options for these emissions. Where control technologies evaluated for control of other pollutants may provide a collateral benefit in reducing emissions of $PM_{2.5}$, this should be evaluated as well.
12. Guidance Reference – The steps followed to perform the BACT analysis mentioned in section 2 are from draft NSR/PSD guidance. The correct reference should be 81 FR 58080, 8/24/2016. As a result of this, some of the steps outlined in the BACT analysis need to be updated.
13. Community Burden Estimate – The concepts and approaches document labels capital purchase and installation costs for air pollution control technology at the major source facilities as "community burden" (see Tables 7 and 8, pages 10-11). EPA believes it is important to properly label the cost numbers being used as capital purchase and installation costs, since presenting them as community burden appears to attribute the entire initial capital investment for the various control technologies to the community in a single year, and also ignores annual operation and maintenance costs. As described in the EPA CCM, the cost methodology used by EPA for determining the cost effectiveness of air pollution control technology amortizes the initial capital investment over the expected life of the control device, and includes expected annual operating and maintenance expenses. EPA believes presentation of this annualized cost over the life of the control technology more accurately represents the actual cost incurred and is consistent with how cost effectiveness is estimated in the context of a BACT analysis.
14. Conversion to Natural Gas – For any emission units capable of converting to natural gas combustion (with the requisite changes to the burners, etc), the MSM analysis in particular

should thoroughly evaluate the feasibility of this option. For example, GVEA has stated the combustion turbines at its North Pole Expansion Power Plant have the ability to burn natural gas, and the IGU has indicated the intent to expand the supply of natural gas to Fairbanks and North Pole.

APPENDIX:

Additional Comments and Suggestions

Possible Concepts and Potential Approaches

Throughout all SIP documents references to design values should include a footnote to the source of the information (e.g., "downloaded from AQS on XX/XX/XXX" or "downloaded from [state system] on XX/XX/XXXX") and how exceptional events were treated.

We suggest referencing the August 24, 2016 81 FR 58010 Fine Particulate Matter NAAQS: State Implementation Plan Requirements rule with one consistent term. We suggest the 2016 $PM_{2.5}$ Implementation Rule.

Page 4, Figure 1. The comparative degree days and heating related information is better suited for the sections evaluating BACM and economic feasibility. If intending on using this information to differentiate Fairbanks from other cold climates and/or nonattainment areas, depicting comparative home heating costs would be more supportive.

Page 4, Table 1. The design values in the table and in the discussion need to be updated for 2015-2017.

Page 6-7: The "Totals" row in Table 3 (non-attainment areas emissions by source sector) does not appear to be the sum of the individual source sector emissions.

Page 7: The statement about FNSB experiencing high heating energy demand per square foot needs to be referenced.

Page 7: The discussion of Eielson AFB growth needs a reference to the final EIS.

Page 9: Table 4's title should be changed to "Preliminary Precursor Demonstration Summary"

Page 9: Table 4 includes a column "Modeling Assessment". Not all precursors were assessed with modeling, and modeling is just one tool for the precursor demonstration. A suggestion for the column title is "Result of Precursor Demonstration."

Page 9: Table 5's title should be changed to "Preliminary BACT Summary." Table 5 also needs to update the title to reference "Precursor Demonstration" as the term "Precursor Significance Evaluation" is the incorrect terminology for this analysis.

Page 10: ADEC's proposal to only require one control measure per major stationary source to meet BACT and MSM for SO_2, is not consistent with the Act or rule. As discussed above, BACM and MSM have separate definitions in 40 CFR 51.1000. By extension, the processes for

selecting BACM and MSM are laid out separately in the PM2.5 SIP Requirements Rule (compare 40 CFR 51.1010(a) for BACM and 40 CFR 51.1010(b) for MSM).

Page 10: Table 6 should identify the specific dry sorbent injection selected as BACT.

Page 11: Suggest changing “less sources” to “fewer sources.”

Page 13: The statement about an I/M program providing PM benefit needs to be clarified. Is this referring just to NOx and VOC precursor contribution to PM2.5, or also direct PM2.5 benefits?

Page 14: The statement “ADEC interprets the main difference between BACT/BACM and MSM as the time it takes to implement a control” is inaccurate. As discussed above, although the rule sets our different schedules for implementation of MSM and BACM, this is not the only major difference between those concepts. Notably, the rule contemplates a higher stringency for MSM as well as a higher cost/ton threshold for determining economic feasibility of the measure.

Technical Analysis Protocol

Page 2: The design values at the top of the page need to be updated to 2015-2017.

Page 2: Recommend removing the sentence “This site will be included in the Serious SIP’s attainment plan…” as the North Pole Elementary will be involved in the redesignation to attainment in the sense that all past and current monitoring data will be a part of an unmonitored area analysis to show that the entire area has attained the standard in addition to the regulatory monitor locations.

Page 2: Remove the discussion of the nonattainment area split.

Page 2: Paragraph 2, sentence 3 should refer to the unmonitored area analysis.

Page 2: The timeline described at the bottom of the page needs to be modified to reflect a current schedule. No projected year modeling was included in the preliminary draft documents. Control scenario modeling will likely not be completed in Q2 2018.

Page 3: We suggest a sentence overview of the unmonitored area analysis in Section 3.1.

Page 3: Section 3.2 needs to refer to the SPM data and how that will be used in the Serious Plan unmonitored area analysis. This section should discuss current DEC efforts to site a new monitor in Fairbanks.

Page 3: Section 3.4 needs to describe the CMAQ domain in addition to the WRF domain. A figure (map) would help.

Page 4: Section 3.5 needs a more developed discussion of the WRF assessment, including describing the criteria that were used to assess the state-of-the-art, what the current version is, and what version was used.

Page 4: Section 3.6 needs to reference all emission inventories in development, including potential attainment date extension years and RFP years.

Page 4: In Section 4.1, the statement about the Moderate SIP covering the relevant monitors for the Serious SIP is inaccurate. The statement needs to qualify whether it is referring to regulatory monitors or non-regulatory monitors. In addition, the North Pole Fire Station, NCore, and North Pole Elementary monitors were not included in the Moderate SIP.

Page 5: Table 4.1-1's title suggests that all SPM sites are listed, but only sites with regulatory monitors are listed. Please list all the SPM sites used in the unmonitored area analysis in a separate table and modify this title of Table 4.1-1 to reflect that it lists sites that are regulatory.

Page 5: North Pole Elementary was a regulatory site for a part of the baseline period and was NAAQS comparable. Table 4.1-1 needs to be updated.

Page 8: Table 4.2-1 should be updated to include 2011-2017 98^{th} percentiles. Table 4.2-2 should be updated to include 3-year design values for 2013-2017. For clarity, we recommend the 3-year design values include the full period in order to better distinguish from Table 4.2-1. For instance, "2013" would be "2011-2013".

Page 8: The statement starting, "a clear indication…" needs to be amended or removed. It is inaccurate. The prevalence of organic carbon does not indicate the dominance of wood burning, much less a clear indication. Many sources in Fairbanks emit organic carbon.

Page 8: The statement starting "The concentration share…" need to be amended or removed. Suggest removing "drastically". There is no scientific definition of a drastic change in percentages of $PM_{2.5}$ species, nor does the different 56% to 80% appear "drastic."

Page 9: The detailed description of the Simpson and Nattinger analysis does not reflect that SANDWICH process and it is preliminary data. It should be included within the body of the Serious Plan appendix on monitoring, but is out of place in a summary TAP.

Page 9: there are two different tables with the same table number (Table 4.3-1).

Page 10: Please clarify Table 4.4-1. This appears to be the design value calculation for the 5-year baseline design value, 2011-2015. If correct, then please label the 3-year design values according to the three years (e.g., "2011-2013"), clarify the table heading as being the "Five Year Baseline Design Value, 2011-2015 (µg/m3)", and clarify that the last column is the 5 Year Baseline Design Value associated with the table heading.

Page 11: At the end of section 5, please refer to the emission inventory chapter's meteorological discussion of the episodes.

Page 11: Section 6 needs to justify the extent, resolution, and vertical layer structure of the CMAQ domain (and the WRF domain) or refer to where that is included in the Moderate Plan.

Page 13: We suggest changing "PMNAA" to "NAA" to be consistent with the EI chapter.

Page 15, Section 8.1: There needs to be mention of how the F-35 deployment will be considered, with a reference to the final EIS.

Page 15-19: section 8.2-8.6 use the future tense for tasks that have been completed and are inconsistent with the schedule at the beginning of the TAP. Please adjust based on current status.

Page 20, section 9.2 states that "a BACT analysis is an evaluation of all technically available control technologies for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts." This sentence should be revised to reflect that the technological feasibility assessment occurs after identification of all potential control measures for each source and source category.

Page 20, section 9.3 the second sentence should read: "BACM measures found to be economically infeasible for BACM *must* be analyzed for MSM."

Page 21: Section 10.1 needs to be updated to reflect the current CMAQ version (5.2.1) and a discussion of why that model has not been used.

Page 21: Suggest sentence starting "There will be a gap…" be changed to "There is a gap in terms of assessing the performance at the North Pole Fire Station monitor for the Serious Plan because the State Office Building in Fairbanks was the only regulatory monitor at the time of the 2008 base case modeling episodes."

Page 23: Please explain the solid and dashed lines in the soccer plot.

Page 23: Please be sure to include a full discussion of North Pole performance in this section. Even though we lack measurements, we can discuss the ratio of the modeling results at NPFS versus SOB versus that ratio from more recent monitoring data (2011-2015 baseline design value period).

Page 23: Please clarify what is meant by "Moderate Area SIP requirements."

Page 24: The discussion of the 2013 base year discusses representative meteorological conditions without describing what the representative meteorological conditions are for high $PM_{2.5}$. Please reference the discussion of representative meteorological conditions that will be found elsewhere in the SIP.

Page 24: The discussion of the modeling years needs to be consistent and reflect the extension request past 2019. The attainment year cannot be earlier than 2019. Each extension year must be individually requested. For modeling efficiency, we recommend starting with 2024. If that year attains, then 2023 and so on until we have one year that attains and the year before that does not. This should give us the information about what is the earliest year for attainment.

Page 25: We suggest changing "modeling design value" to "design value for modeling"

Page 26: Please clarify the "SMAT" label in the tables. They may be the SANDWICH concentrations and the "5-yr DV" rows are the SMAT concentrations. Please clarify the units in the rows.

Emission Inventory

Clarification – In the EI document we would like to understand the functional difference between the base year, and baseline year

Please identify the methodology for generating ammonia and condensable PM emissions numbers.

Page 1: Please be consistent in “emission inventory” versus “emissions inventory”.

Page 1: “CAA” to “Clean Air Act” for clarity

Page 3: It would be helpful to refer to 172(c)(3) in Section 1.2, bullet 1 as the planning and reporting requirements.

Page 5: Please include extension years and RFP years in Table 1’s calendar years similar to what was done for Table 2. There should be one RFP projected inventory and QM beyond the extended attainment date. It would be helpful to include basic information about extension years and RFP years to better foreshadow Table 2.

Page 7: Please clarify the “winter season” inventory as the “seasonal” inventory that represents the daily average emissions across the baseline episodes.

Page 7, paragraph 1. Please include reference documentation for the following statement, “results in extremely high heating energy demand per square foot experienced in no other location in the lower-48.”

Page 9: Please change “Violations” to “Exceedances.” Exceedance is the term for concentrations over the standard. Violations is the term for dv over the standard.

Page 9: Add “No exceedances were recorded outside the months tabulated in Table 3 that were not otherwise flagged by Alaska DEC as Exceptional Events.”, to the end of the last paragraph on the page.

Page 13: Please clarify the provenance of the BAM data (e.g., “downloaded from [state database or AQS] on XX/XX/XXXX). In particular, it is important to note if the data has been calibrated to the regulatory measurement (aka, corrected BAM).

Page 17-18. Sentence Unclear “For example, a planning inventory based on average daily emissions across the entire six-month nonattainment season will likely reflect a relatively lower fraction of wood use-based space heating emissions than one based on the modeling episode day average since wood use for space heating Fairbanks tends to occur as a secondary heating source on top of a “base” demand typically met by cleaner home heating oil when ambient temperatures get colder.”

Page 19: Remove “Where appropriate,”. All source sectors should be re-inventoried for 2013, even if the emissions for the sector ends up being the same as in 2008.

Page 19: Change “projected forward” to “re-inventoried”, or similar wording. Reserve “project” for when the emission inventory is estimating emissions in a future year.

Page 20: Please refer to EPA’s memo on the use of MOVES2014a for the plug in adjustment. As a reminder, this information is sufficient only for development of the emissions inventory, not for SIP credit.

Page 20: Please submit the technical appendix referenced on page 20. When that is submitted, we expect to provide additional comment. To allow for review, we request expedited submission.

Page 21: At bottom of page, “project” should be “re-inventoried” or something that refers to an inventory produced after the fact.

Page 22, paragraph 1, Space heating area sources. Please further explain how the combined survey data best represents 2013 emissions.

Page 23: Add information about how NH_3 was inventoried for this category.

Page 23, 2nd paragraph from bottom. Facilities need to provide direct PM and all precursors, whether directly submitted or calculated from emissions factors.

Page 23, last paragraph.

- Potential typo – we believe that 2018 should be 2013.
- Question – Does scaling emissions cause any point source to exceed its PTE?

Page 25, bullet 3, Laboratory – Measured Emissions Factors for Fairbanks Heating Devices. The statement “first and most comprehensive systematic” would be more credible if simplified.

Page 27: Clarify how data from the 2014 NEI was modified to reflect emissions in 2013. Were they assumed to be the same between the two years? Or adjusted based on population change, or some other information?

Page 33: Please include information on how the Speciate database was used to develop the modeling inventory (and perhaps elsewhere for the planning inventory, if appropriate).

Precursor Demonstration

Throughout the Serious Area SIP we recommend using the terminology, Precursor Demonstration, to be consistent with the $PM_{2.5}$ Implementation Rule.

General: The overview of the nitrate chemistry is complicated. We suggest you combine the two discussions into one and organize it with the following logic:

1. Describe the two chemical environments: (1) daytime and (2) nighttime.
2. Describe the information that supports that daytime chemistry is not relevant here.
3. Describe the information that supports that nighttime chemistry is limited by excess NO.

4. Describe what happens if the entire emission inventory was increasing by a factor of 3.6 to get appropriate concentrations in the North Pole area. How does ammonium nitrate change?
5. Describe how increasing the emission inventory and then reducing all source sectors by 75% results in less of a reduction in $P_{M2.5}$ than reducing all source sectors by 75% in the original emission inventory.
6. NOTE: We are willing to provide a rough draft of this organization, if provided the original word document.

Title page: remove "com"

Page 2: Recommend using Section 188-190 instead of 7513-7513b.

Page 2: Recommend moving the last three sentences of the first paragraph to the end of the second paragraph.

Page 2: Please add "threshold" after 1.3 in the third paragraph.

Page 2: Please explain concentration-based and sensitivity-based before using the terms.

Page 2: Please add a footnote whether the numbers in the Executive Summary are SANDWICHed or not.

Page 3: Please change "has decided" to "decided."

Page 3: Make sure the concentrations listed for ammonia include ammonium sulfate and ammonium nitrate.

Page 5-7: The figure captions say that concentrations are presented but the images themselves have percentages. Please use concentrations for this analysis.

Page 9: The first paragraph says that the point sources are not responsible for the majority of sulfate at the monitors. Please substantiate that claim, or modify it.

Page 13: Please explain the relevance of referring to the VOC emissions of home heating in this summary of VOCs.

Page 14: Recommend adding "… and adjusted to reflect speciated concentrations for a total PM2.5 equal to the five year 2011-2015 design value" to the sentence that starts "The speciated PM2.5 data [were] analyzed.

Page 14: Please include the results of the concentration based analysis, perhaps as a table.

Page 14: Clarify that the concentration used for NH_3 is the ammonium sulfate and ammonium nitrate. See the draft EPA Precursor Demonstration Guidance.

Page 17: Recommend removing "slightly" and removing the sentence referring to rounding to the nearest tenth of a microgram.

Page 17-18: To help understand what is going on with the bounding run versus the normal run, it would be helpful to have the RRFs for the Modeled 75% scenario.

BACM

Page 9 and throughout: For clarity, please refer to the implementation rule as "$PM_{2.5}$" not "PM".

Page 14, Table 3. It would be helpful to include filter speciation data.

Page 16, Table 4: Please identify the RACM measures that were technologically and economically feasible but could not be implemented in the RACM timeline or note there were none.

Page 20 and 25, Table 6 and 7: For the final Table identifying the control measures evaluated, it would be helpful to identify the following: measure, cost/ton, BACM determination, MSM determination, and any additional comments.

Page 24: 12 measures were eliminated because they were determined to offer marginal or unquantifiable benefit. However, a measure may offer marginal benefit but may also cost very little. If there is another explanation for why these measures were not considered that follows the BACM steps, please include that in the Serious Area Plan.

Page 28: Stage 1 alerts are referred to multiple times including in Measure 2 on page 28 and Measure 33, pg 47 and pg 48. Please clarify in these analyses whether the measure applies during all stages of alerts and the associated level of control with each stage.

Page 33: Measure 13 identified that no SIPs existed or EPA guidance/requirements for the measure and incorrectly used that rationale as the conclusion for not considering the measure.

Page 34: The discussion of Measure 15 does not clearly state how Alaska and the Borough ensure that devices are taken out at the point of sale. It also does not clearly state the process for ensuring a NOASH application doesn't involve a stove that should have been taken out at the point of sale. It also states that stoves between 2.5 g/hr and 7.5 g/hr can get a NOASH, whereas page 37 implies that a stove must be <2.5 g/hr to be eligible for a NOASH.

Page 47: Measure 33 in Klamath County and Feather River is more stringent than what exists in Fairbanks now. Fairbanks allows open burning without a permit when there is no stage restriction. Alaska DEC prohibits open burning between November 1 and March 31, but the air quality plan makes it clear that the state relies on the Borough to carry out the air quality program in Fairbanks. The fact that the local borough does not require a permit for open burning outside of curtailments makes this measure less stringent in Fairbanks than in other locations. In addition, Fairbanks does not curtail warming fires during a Stage 1.

Page 48: Measure 34 is less stringent in Fairbanks than in Klamath County. Uncertainty in weather forecasting means that Stage 1 alerts are not called correctly all the time, and not

everyone is aware of when an alert is in effect. It is much simpler and less prone to error to prohibit burn barrels and outdoor burning devices entirely.

Page 57: Measure 46 review curtailment exemptions. The current Fairbanks curtailment exemption "These restrictions shall not apply during a power failure." should be reviewed to clarified that it only applies to homes reliant on electricity for heating. As currently written, it appears overly broad.

Page 68: Measure R7, Ban Use of Hydronic Heaters, incorrectly identifies that no other SIPs implemented the measure as rational for not evaluating.

Page 72: Measure R15 is technologically feasible.

Page 78: It may help to make a section break or Section 2 label for "Analysis of Marginal / Unquantifiable Benefit BACM Measures

Page 81-83: The discussion of Measure 6 may need additional documentation. Anecdotal evidence is that damping is common in Fairbanks and is potentially a bigger source of pollution than not having a damper at very cold conditions. If installation by a certified technician addresses this issue, that should be documented.

Page 84: The quote, "did not know if the rule had worked well" needs a reference. It is also not clear of how relevant that is. It could be implemented well in Fairbanks and the fact that it may not have worked well in another location does not make it technologically infeasible for this location.

Page 85-86: While qualitative assessments are helpful to provide context, a quantitative assessment will be necessary to evaluate the measures as BACM and MSM.

Page 88: There are references to Fairbanks in the conclusion for Measure 17, but the analysis refers to AAC code.

Page 89: There appears to be missing text in the Background section related to Method 9.

Page 91: Measure 23 could consider the solution that the decals could be reflective and would be seen by vehicle headlights. Measure 23 could also consider that the decals are used by neighbors to determine who is or is not in compliance. This may be helpful as citizen compliance assistance efforts could supplement the Borough enforcement program.

Page 98-100: Measure 40 needs to include a discussion of all the areas listed on page 22. In addition, if a date certain measure or if Measure 29 were instituted, Measure 40 would essentially be achieved.

Page 114: Measure R5 describes a similar rule in Utah but lists "none" under implementing jurisdictions. Please make consistent.

ULS Heating Oil

Page vii and Page 16: Please check your information on the percentage of households who have a central oil fired furnace. Please consult ADEC's contractor for the emissions inventory and home heating surveys about (1) the percentage of homes that heat only with an oil furnace, and (2) home with a central oil burner and a wood stove. We have seen different numbers than presented here.

Page 13: Please check the labels for Fairbanks HS #2 and Fairbanks HS #1. They may be switched.

Page 14: The statement that there is "a clear explanation" may not be correct, or at minimum is an overstatement. The difference in price between HS#1 and ULSD has varied over time, and the report did not include an explanation for the variations.

Page 14: The third paragraph assumes that the capital costs of shipping ULS would be more than exists today. However, all heating oil is shipped, regardless of sulfur content, and there is no justification for the report for why shipping ULS would be higher than for HS. Additionally, it is possible that the shipping cost per unit could go down marginally if only one product is being supplied to Fairbanks and/or if the quantity supplied increases.

Page 21: The text and Table 7 present inconsistent information. For instance, the text says that the discounted net-present value of scenario 2 is $10,232 while the table says it is $5,768.56.

November 28, 2018

Certified Mail
Return Receipt Requested
7017 1450 0002 1773 7925

Denise Koch, Director
Division of Air Quality
Department of Environmental Conservation
410 Willoughby Avenue, Suite 303
PO Box 111800
Juneau, AK 99811-1800

RE: Best Available Control Technology (BACT) Proposal from Golden Valley Electric Association (GVEA) for the North Pole Power Plant and Zehnder Facility.

Dear Ms. Koch,

At the request of the Alaska Department of Environmental Conservation (ADEC), Golden Valley Electric Association (GVEA) has considered alternative Best Available Control Technology (BACT) proposals and in this communication is providing updated and supplemental information. GVEA hopes this additional information is beneficial to ADEC as the Serious $PM_{2.5}$ State Implementation Plan (SIP) is finalized.

Introduction

Due to geography, our northern latitude, climatology, and types of emissions within the Fairbanks North Star Borough (FNSB), concentrations of $PM_{2.5}$ often exceed the maximum levels set by the Clean Air Act; resulting in the area being designated as being in non-attainment of the National Ambient Air Quality Standards (NAAQS) for the 24-hour $PM_{2.5}$ standard in 2009. As original attainment goals were not met, the area was reclassified as a Serious non-attainment area (NAA) and ADEC is working to finalize and submit to EPA an approvable Serious SIP that will outline methodologies for reaching attainment.

GVEA operates two stationary sources within the NAA, the North Pole Power Plant and the Zehnder Facility. With the Serious designation, ADEC requested stationary sources conduct a voluntary BACT analyses for emissions of $PM_{2.5}$ or its precursors (SO_2, NO_x, VOCs and NH_3) that have the potential to be emitted at 70 or more tons per year. GVEA prepared and submitted BACT analyses for both the North Pole and Zehnder plants that analyzed NOx and

SO_2 BACT. All NO_X and SO_2 control options evaluated were deemed infeasible by GVEA. Subsequently, ADEC proposed modifications to GVEA's calculations and presented these in draft BACT documents early in 2018. For NO_x BACT, ADEC's determination included Selective Catalytic Reduction (SCR) and water injection for the two simple cycle gas turbines at both North Pole and Zehnder, and SCR for the combined cycle turbine at North Pole. For SO_2 BACT, ADEC's determination included ULSD for the two simple cycle gas turbines at both North Pole and Zehnder.

In the March 2018 draft documents, ADEC included a draft NO_x precursor demonstration which will show that NOx emissions are not a significant contributor to secondary $PM_{2.5}$ concentrations. ADEC has communicated a high degree of confidence the NO_x precursor demonstration will be accepted and the implementation of NOx controls will not be required. As such GVEA is not addressing any new BACT considerations related to NO_x controls and is focusing on alternative proposals for SO_2 BACT at both plants[1].

Alternative BACT Request

ADEC has been sympathetic to concerns raised by the stationary sources that potential community burden in capital investment for SO_2 controls is unusually high compared to the potential benefit to $PM_{2.5}$ concentrations at ground level; concentrations which are highly influenced by home heating and especially wood burning. ADEC has asked GVEA to consider alternative BACT proposals including the option of paying into an offset fund with the caution that creative and alternative proposals would have to be measurable and enforceable. Though an offset fund could be an options, there are two reasons GVEA does not see contributions to an offset fund as a viable option. First, GVEA does not see a way at this time to equitably incorporate offset fund payments into our member rates. Second, with no assurances that further investments into BACT controls would not be necessary if attainment goals are not met, the potential for investment into both an offset fund and BACT is a deterrent.

GVEA has identified modifications in combustion fuel and operating hours as options available to reduce SO_2 emissions at GVEA's two affected facilities and presents three proposed alternatives in order of descending preference below.

Alternative SO_2 BACT Option 1
Existing Fuels and Good Combustion Practices for North Pole and Zehnder

Current Fuel Supplies

GVEA currently receives all fuel from Petro Star Inc. (PSI) with the majority coming from the local North Pole Refinery adjacent to the North Pole Power Plant. In 2017 the combined cycle turbine at North Pole (EU ID 5) began receiving a Light Straight Run (LSR) naphtha product directly from the Petro Star North Pole Refinery (PSI) via pipeline. The sulfur content of this fuel

[1] At this time, GVEA has no comment on ADEC's modifications to the NOx control calculations.

was specified to be below 30 ppm and extensive testing conducted in 2018 showed a maximum sulfur content of 27 ppm. Less than two percent of the fuel received is composed of other naphtha fuels that have sulfur contents less than 50 ppm. Assuming a maximum fuel sulfur content of 50 ppm would conservatively change the potential SO_2 emissions from this unit and the proposed second LM6000 (EU ID 6) from 6 to 10.1 tons per year (TPY). Tables 1-2 and 1-5 in GVEA's North Pole BACT analysis would be affected by this change and are included in Attachment 1.

High sulfur diesel (HSD) is trucked from the pipe rack at PSI's North Pole facility across the street to a 50,000 gallon holding tank that supplies the two GE Frame 7 gas turbines at the North Pole Plant (EU IDs 1 and 2). Similarly, HSD is trucked from PSI North Pole to the Zehnder Plant GE Frame 5's (EU IDs 1 and 2). The large majority of the fuel is No. 2 HSD that is blended with No. 1 in the winter to lower the pour point. No. 1 HSD is received on rare occasions. ULSD is trucked from PSI's Valdez refinery for use as a starting fuel and is used in smaller quantities. During times when the North Pole refinery is down for planned maintenance outages, additional ULSD is trucked to Fairbanks for production fuel.

BACT Capital Cost Assumptions

GVEA's original BACT and ADEC's proposed BACT evaluated switching to ULSD to reduce SO_2 emissions. These analyses included capital costs for bulk fuel storage to maintain reliability and security of fuel supply; these costs were apportioned between the North Pole and Zehnder plants.

If GVEA were to use ULSD for both starting and production fuel in the Frame 7's and Frame 5's, as considered for SO_2 BACT, the addition of bulk fuel storage would be required to guarantee availability of fuel for the generation units since there is no locally refined source of ULSD[2]. Fuel can be imported from the Valdez area using trucks, or from the Anchorage area using trucks or rail. Both transportation corridors are subject to disruptions from avalanches, flooding, snow storms, forest fires, or earthquakes that could delay fuel delivers. For example, a video clip available online[3] shows a massive avalanche caused ice dam that closed the single road connecting Valdez in January 2014, an avalanche accompanying record snow fall closed the road to Valdez in December 6, 2017, the 2002 Denali Fault earthquake (7.9 on the Richter scale) damaged more than 20 miles of the roadbed between Fairbanks and Valdez[4], and flooding in 2006 closed the Parks Highway near Anchorage for several days[5].

During the short annual PSI maintenance outages (occurring during summer months) GVEA has experienced near outages of fuel when it is delivered solely through long haul trucking,

[2] GVEA uses "neat" fuel for generation that does not contain the additives that are added to most fuel currently stored locally.
[3] https://www.youtube.com/watch?v=X3XzRHLYE0Y video footage of avalanche ice dam isolating Valdez.
[4] https://www.fhwa.dot.gov/publications/publicroads/03nov/05.cfm Denali Fault earthquake.
[5] https://www.matsugov.us/news/4-a-m-flood-and-road-updates Parks highway closure for flooding.

largely because the long haul (700 miles round trip versus .5 miles) complicates the timing of truck offloading. This experience with supply issues, and the potential for transportation disruption, raises concerns with the reliability of year round long hauled fuel supplies on a "just in time" basis from either Valdez or Anchorage, and particularly during the coldest winter months. In 2017, GVEA hired PDC Engineering of Fairbanks to assist in developing a concept design and cost estimate for a bulk fuel tank farm and terminal facility adjacent to the North Pole Power Plant. The technical memo presenting the conceptual study is included as Attachment 2.

As part of the BACT analyses, GVEA sought input from Delma Bratvold, an Energy Analyst with Leidos Engineering, to help extrapolate the PDC concept design. Ms. Bratvold has a long history of assisting GVEA with strategic fuel evaluations and her BACT specific summary is included as Attachment 3, presenting the estimated costs of strategic bulk fuel storage for both the North Pole Plant and Zehnder Facilities based on both potential to emit (PTE) run hours and historic run hours.

Fuel Cost Assumptions

In preparing the original BACT analyses, GVEA used actual fuel costs incurred from August 2015 through April 2016 to obtain a cost differential of $0.2668 per gallon between ULSD and No. 2 HSD. Attachment 4 shows updated pricing data for fuel received between January 2017 and October 2018 and shows an updated weighted average cost differential of $0.424 per gallon between No. 2 HSD and ULSD[6].

Cost Effectiveness

Appling the updated incremental fuel pricing increases the cost effectiveness of SO_2 removal for all primary generating units. Table 1 summarizes the cost effectiveness of switching to ULSD for the primary generating units and compares the iterations in calculations, from GVEA's original, the ADEC's to GVEA's updated. The updated cost effectiveness tables from the BACT analyses are included in Attachment 5[7].

[6] A digital version of Attachment 4 is included on the enclosed DVD.

[7] Tables referenced in this correspondence refer to similarly numbered tables in GVEA's original BACT analyses. ADEC returned to GVEA proposed modifications to the BACT tables as Excel files following ADEC's preliminary review. GVEA's most current updates are applied to ADEC's version. Updates described here are attached in hard copy and included on the accompanying DVD.

Table 1. Cost Effectiveness, $/Ton of SO_2 removal[1]			
	GVEA's 2017 BACT Cost Effectiveness ($/Ton) [2]	ADEC's Cost Effectiveness ($/Ton) [3]	GVEA's 2018 Alternative BACT Cost Effectiveness ($/Ton) [4]
North Pole			
EU ID 1	$10,025	$9,139	$13,942
EU ID 2	$10,204	$9,233	$14,037
EU ID 5/6	$9,282,151	$9,282,151	$4,844,020 [5]
Zehnder			
EU ID 1/2	$9,701	$9,050 [6]	$14,250

[1] Capital costs of $30,425,000 to install fuel storage are apportioned between North Pole and Zehnder and the cost effectiveness calculations for both plants are based on the Potential to Emit. The cost effectiveness based on actual emissions and on the conversion of SO2 to PM2.5 is significantly higher.
[2] Tables 5-4, 5-5, and 5-6 in GVEA's original BACT for North Pole and Table 5-4 in the original BACT for Zehnder.
[3] Tables 5-4, 5-5, and 5-6 in ADEC's modified BACT tables for North Pole and Table 5-4 for ADEC's modified Zehnder BACT calculations
[4] Updated Tables 5-4, 5-5, and 5-6 are included in Attachment 5. The Excel file is included on the enclosed DVD.
[5] As shown on included tables and discussed above, increasing the naphtha fuel from 30 ppm to 50 ppm sulfur content increases the potential annual SO_2 emissions from 6 to 10.1 tons and decreases the cost effectiveness.
[6] ADEC's proposed cost effectiveness for Zehnder was based on avoiding 597 tons SO_2 per year. Condition 9 of Permit No. AQ0109TVP03 already places an Owner Requested Limit (ORL) on SO_2 Emissions of 580 tons per rolling 12-month period for the Zehnder Facility. Considering the ORL, the cost effectiveness is $9,340 per ton removed.

With a cost effectiveness above $13,000 per ton of SO_2 removed, GVEA contends that switching to ULSD is not economically feasible and BACT would be the existing fuels and good combustion practices for all units at North Pole and Zehnder.

ADEC has suggested No. 1 HSD with a sulfur content of 900 ppm be considered as an alternative to No. 2 HSD. Currently, No. 1 HSD produced locally by PSI is not available in large enough quantities to be used as a production fuel. PSI is undertaking engineering studies to identify ways to expand their local production of No. 1 HSD, however they have indicated there will be competing demands; the military use is forecast to increase by 50%, and there is the projected conversion of home heating to No. 1 HSD. Production fuel for GVEA would be a non-dedicated supply and last on the priority list behind the military and home heating demands. PSI has indicated they would likely import fuel from Valdez to meet GVEA's full demands. To have a guaranteed fuel supply, this would place GVEA in a situation similar to importing ULSD with similar pricing and reliability constraints. To fully switch to No. 1 HSD would have a cost effectiveness similar to ULSD.

Alternative SO_2 BACT Option 2
North Pole - No. 1 HSD (EU IDs 1&2) on Air Quality Stage 1 and 2 Curtailment Days
Zehnder - Existing Fuels and Good Combustion Practices

North Pole Power Plant Option 2

GVEA wishes to be a constructive contributor to improving regional $PM_{2.5}$ concentrations with practical solutions that do not unfairly burden our cooperative members with negligible benefit.

As such, GVEA proposes as SO_2 BACT for North Pole EU ID's 1 and 2, the continued use of No. 2 HSD during normal operating days, with a switch to receiving No. 1 HSD (when available) when the units operate on air quality curtailment days (during Stage 1 and Stage 2 air quality alerts for the North Pole area). It will take an estimated 5 to10 operating hours to fully transition fuel. With the recent addition of Healy Unit 2 to the generation fleet, which economically produces electricity outside the NAA, GVEA anticipates the actual operation of EU ID's 1 and 2 to be reduced. New Tables 5-4a and 5-5a in Attachment 6 evaluate the cost effectiveness of targeted operation on No. 1 HSD, assuming 10% of the time, at $1,904 per ton of SO_2 avoided.

GVEA proposes as SO_2 BACT for EU ID's 5 and 6, the continued use of the current or equivalent fuels with a sulfur content of 50 ppm or less.

Zehnder Facility Option 2

GVEA proposes as SO_2 BACT the existing fuels and good combustion practices for all units at Zehnder. Condition 9 of Permit No. AQ0109TVP03 already places an Owner Requested Limit (ORL) on SO_2 Emissions of 580 tons per rolling 12-month period for the Zehnder Facility[8]. EU ID's 1 and 2 are the least economical units to run and are run only when absolutely necessary. Attachment 7 shows the 2017 actual operating hours and emissions for the Zehnder Facility as presented in the March 2018 assessable emissions estimates. These emissions are representative of operations from 2012 through 2018 (year to date) where the total SO_2 emissions have been slightly over 30 tons per year. As mentioned above, with the addition of Healy Unit 2 the Zehnder Units are modeled to run even fewer hours.

[8] If the ORL was reduced to 350 tons per year, the cost effectiveness of ULSD as evaluated in Table 1 goes to $21,989 per ton of SO_2 reduced.

Alternative SO_2 BACT Option 3
North Pole - No. 1 HSD (EU IDs 1&2) on Air Quality Stage 1 and 2 Curtailment Days
Zehnder - ORL to Remove Zehnder as a Major Source of SO_2

North Pole Power Plant Option 3 (same as Option 2)
Similar to Option 2, GVEA proposes to supply No. 1 HSD to EU ID's 1 and 2 when they are operating during air quality Stage 1 and Stage 2 alerts in the North Pole area. SO_2 BACT for EU ID's 5 and 6, would again be the continued use of the current or equivalent fuels with a sulfur content of 50 ppm or less.

Zehnder Facility Option 3
GVEA recognizes the traditional BACT process evaluates the potential to emit pollutants of concern, and the Zehnder Facility has the potential to emit many more tons of SO_2 than it historically has. The Zehnder units are the least economical to run and are run only when necessary, however, they are a critical piece to the overall system reliability and their operation is necessary in cases when other generating units are down, or the transmission Intertie with the Anchorage area is down.

As a third option, GVEA proposes to take an additional ORL on SO_2 emissions to limit them to less than 70 tons per year, thus removing the Zehnder Facility as a major source of SO_2. GVEA proposes to submit the request for permit modification by June 1, 2019 and would structure the modification to allow for operation in emergency situations. The health and welfare of GVEA's members are of upmost importance and in consideration of the extreme temperatures and winter conditions that can be experienced in the FNSB, GVEA must be able to supply electrical power to members when other sources are unavailable. Attachment 8 shows a guide used internally to prioritize outage response. For a range of outside temperatures it tabulates the time to a complete house freeze up after the loss of a heat source. With an external temperature of -30 F, a house starting with an internal temperature of 70 F can be expected to freeze after seven hours.

Other Measures

Though not measurable, enforceable, or appropriate for inclusion in the SIP, GVEA is exploring other alternatives that will help minimize emissions from power generation within the non-attainment area.

With the successful restart of Healy Unit 2, the consumption of No. 2 HSD in the North Pole and Zehnder Units has dropped from 12.4 million gallons in 2017, to an estimated 9 million gallons in 2018, to a projected 5.5 million gallons in 2019. In 2019, total SO_2 emissions in the NAA from GVEA's plants is expected to drop 192 tons over 2017. GVEA has modeled the effect of retiring Healy Unit 1 and power would be made up with both purchases from the Anchorage area and generation within the NAA. With the removal of Healy Unit 1, modeling shows an increase in NAA SO_2 emissions from the North Pole and Zehnder Plants of 28%. Options for continuing the

operation of Healy Unit 1 are being evaluated.

GVEA is also exploring options that may assist the Interior Gas Utility (IGU) in providing economical natural gas to the Fairbanks area. If feasible, GVEA may be able to convert North Pole EU ID 5 to also burn natural gas, which could help stabilize demand, or help reach some economies of scale for gas supply.

All the sources within FNSB NAA are integrally related and requirements for one source may have unintended consequences for another. As GVEA is the sole purchaser of Aurora Energy's electrical production, any BACT capital investment Aurora makes can potentially affect GVEA's member rates. Knowing that the exact accounting and correlation between the major source SO_2 stack emissions, the at-the-monitor measurements, and the modeling are inconsistent, GVEA encourages ADEC to pursue a Major Source SO_2 precursor demonstration and to work further to explain the sulfate contribution inconsistencies.

Summary

In conclusion, GVEA would like to make meaningful contributions to reducing SO_2 emissions without disproportionally burdening our member owners or sacrificing electrical system reliability. Three BACT options have been presented, in all cases for North Pole's existing EU ID 5 and proposed EU ID 6 (the combined cycle plants at North Pole) GVEA proposes to burn the existing or equivalent fuel with a sulfur content of 50 ppm or less.

As a first option, using updated fuel pricing and the actual differential costs between No. 2 HSD and ULSD, GVEA is submitting updated cost effectiveness calculations for SO_2 reductions at both the North Pole and Zehnder plants that show costs over $13,000 per ton of SO_2 reduced. GVEA proposes as SO_2 BACT the continued use of current fuels and good combustion practices for all units at North Pole and Zehnder.

As a second option, to make reductions in SO_2 emissions during times when they are needed, For EU ID's 1 and 2, the older simple cycle plants at North Pole, GVEA proposes to continue burning No. 2 HSD during normal operations, but to take delivery of No. 1 HSD[9] while operating during air quality curtailment periods.

As a final option, in addition to receiving No. 1 HSD during curtailment periods at North Pole, GVEA proposes to take an additional ORL at the Zehnder Facility to reduce annual SO_2 emissions to less than 70 tons, except in emergency situations.

[9] Subject to availability as GVEA would be third in line of preference behind Military demands and proposed home heating demands.

Sincerely,



Naomi Morton Knight, P.E.
Environmental Health & Safety Officer

Attachments/Enclosures:

- Attachment 1 - North Pole BACT Section 1 Tables
- Attachment 2 - Technical Memo from PDC Regarding Bulk Fuel Storage
- Attachment 3 - Leidos Strategic Fuel Evaluation
- Attachment 4 - January 2017 through October 2018 Fuel Prices
- Attachment 5 - Updated Cost Effectiveness Tables North Pole and Zehnder
- Attachment 6 - Tables 5-4a and 5-5a, North Pole EU ID 1 and 2 Cost Effectiveness with Selective use of No. 1 HSD
- Attachment 7 - Zehnder FY2019 Assessable Emissions Summary
- Attachment 8 - House Freeze Up Time Estimates.
- DVD

GVEA
Alternative BACT
November 2018

Attachment 1
North Pole BACT Section 1 Tables

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Table 1-2. Significant Emission Unit Potential Emission Inventory

Emission Unit			Fuel	Rating	Maximum	Allowable Annual	Construction	Life	Potential Emissions (tpy)			
ID	Description	Make/Model	Type		Capacity	Operation	Date	Span	NO_X [1]	$PM_{2.5}$	SO_2 [2,3]	VOC
1	Simple Cycle Gas Turbine	GE Frame 7, Series 7001, Model BR	Fuel Oil	60.5 MW	672 MMBtu/hr	8,760 hr/yr	1976	10 years	1,600.0	35.3	1,486.4	1.2
2	Simple Cycle Gas Turbine	GE Frame 7, Series 7001, Model BR	Fuel Oil	60.5 MW	672 MMBtu/hr	7,992 hr/yr[4]	1977	10 years	2,363.1	32.2	1,356.1	1.1
3	Fuel Storage Tank	N/A	HAGO/LAGO/ Fuel Oil[5]	50,000 Gallons	50,000 Gallons	8,760 hr/yr	1995	10 years	0	0	0	0.04
4	Fuel Storage Tank	N/A	HAGO/LAGO/ Fuel Oil[5]	50,000 Gallons	50,000 Gallons	8,760 hr/yr	1995	10 years	0	0	0	0.06
5	Combined Cycle Gas Turbine	GE LM6000PC	GVEA LSR Turbine Fuel/GVEA Naphtha[6]	43 MW	455 MMBtu/hr	8,760 hr/yr	2005	10 years	478.3	23.9	10.1	0.8
6	Combined Cycle Gas Turbine	GE LM6000PC	GVEA LSR Turbine Fuel/GVEA Naphtha[6]	43 MW	455 MMBtu/hr	8,760 hr/yr	N/A	10 years	478.3	23.9	10.1	0.8
7	Emergency Generator Engine	Generac 5231150100	Fuel Oil	400 kW	461.6 kW	52 hr/yr[7]	2005	10 years	0.5	0.04	0.01	0.0
11	Boiler	Bryan Steam RV500	Gas Fuel/Propane	5.0 MMBtu/hr	5.0 MMBtu/hr	8,760 hr/yr	2005	10 years	3.1	0.2	0.0003	0.2
12	Boiler	Bryan Steam RV500	Gas Fuel/Propane	5.0 MMBtu/hr	5.0 MMBtu/hr	8,760 hr/yr	2005	10 years	3.1	0.2	0.0003	0.2
								Total Potential Emissions	3,969.8	115.7	2,862.6	4.5

[1] Combined emissions from EU IDs 1, 5, and 6 are limited to 1,600 tpy emissions of NO_X on a 12-month rolling basis per Permit AQ0110TVP03, Condition 13. Each emission unit can operate individually up to the potential NO_X emissions shown above.

[2] EU IDs 1 and 2 can combust No. 1 and No. 2 fuel oil, which (by specification) can have a maximum sulfur content of 0.5 wt. pct. The two emission units may emit no more than 24,500 pounds of SO_2 per day, combined, per Permit AQ0110TVP03, Condition 14. The fuel oil sulfur content specification of 0.5 wt. pct. S is more restrictive. Each unit could be operated individually up to the potential SO_2 emissions shown above.

[3] EU IDs 5 and 6 are limited to a combined 12-month rolling total consumption of 1.5 million gallons of startup fuel per Permit AQ0110TVP03, Condition 16.1. Each unit could be operated individually up to that limit.

[4] EU ID 2 is limited to operating no more than 7,992 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 12.

[5] HAGO and Lago are listed for completeness, but those fuels are no longer available due to the closure of the Flint Hills Refinery in North Pole.

[6] GVEA LSR Turbine Fuel (LSR) is currently being combusted in EU ID 5. This fuel is obtained from directly from the Petro Star Inc. (PSI) refinery via pipeline. PSI is supplying this fuel under a long-term contract with GVEA.

[7] EU ID 7 is limited to operating no more than 52 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 10.

Table 1-3. Significant Emission Unit Potential NO_X Emissions

Significant Emission Units		Factor	NO_X Emission	Maximum	Maximum	Regulatory Limits	Existing Control Technology		Potential NO_X
ID	Description	Reference	Factor	Capacity	Operation		Description	Efficiency (pct.)	Emissions
1	Simple Cycle Gas Turbine	AP-42 Table 3.1-1	0.88 lb/MMBtu	672 MMBtu/hr	8,760 hr/yr	NA	Regenerative System	Unknown	1,600 tpy [1]
2	Simple Cycle Gas Turbine	AP-42 Table 3.1-1	0.88 lb/MMBtu	672 MMBtu/hr	7,992 hr/yr[2]	NA	Regenerative System	Unknown[6]	2,363.1 tpy
3	Fuel Storage Tank	NA	NA	50,000 Gallons	8,760 hr/yr	NA	NA		0 tpy
4	Fuel Storage Tank	NA	NA	50,000 Gallons	8,760 hr/yr	NA	NA		0 tpy
5	Combined Cycle Gas Turbine	AP-42 Table 3.1-1	0.24 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	Subpart GG 146 ppmvd at 15 pct. O_2	Water Injection	73 [3]	478.3 tpy [1]
6	Combined Cycle Gas Turbine	AP-42 Table 3.1-1	0.24 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	Subpart KKKK 74 ppm at 15 pct. O_2 or 3.6 lb/MWh	Water Injection	73 [3]	478.3 tpy [1]
7	Emergency Generator Engine	AP-42 Table 3.3-1	0.031 lb/hp-hr	461.6 kW	52 hr/yr[5]	NA	Turbocharger and Aftercooler + Limited Operation	99	0.5 tpy
11	Boiler	AP-42 Table 1.5-1	13 lb/10^3gal	5.0 MMBtu/hr	8,760 hr/yr	NA	NA		3.1 tpy
12	Boiler	AP-42 Table 1.5-1	13 lb/10^3gal	5.0 MMBtu/hr	8,760 hr/yr	NA	NA		3.1 tpy
							Total Potential Emissions		3,969.8 tpy[4]

Sample Calculations:

Turbine Emissions, tpy= (Emission factor, lb/MMBtu) * (Capacity, MMBtu/hr) * (Operation, hr/yr) / (2,000 lb/ton)

Engine Emissions, tpy= (Emission factor, lb/hp-hr) * (Capacity, kW) * (Conversion, 1.341 hp/kW) * (Operation, hr/yr) / (2,000 lb/ton)

Heater (Boiler) Emissions, tpy= (Emission factor, lb/10^3gal) * (Conversion, 10^3gal/91.5 MMBtu) * (Capacity, MMBtu/hr) * (Operation, hr/yr) / (2,000 lb/ton)

- Propane heat content is assumed to equal 91.5 MMBtu/10^3 gallon per AP-42 Table 1.5-1.

Notes:

[1] Combined emissions from EU IDs 1, 5, and 6 are limited to 1,600 tpy NO_X emissions on a 12-month rolling basis per Permit AQ0110TVP03, Condition 13. Each unit can operate individually up to the potential emissions shown above.

[2] EU ID 2 is limited to operating no more than 7,992 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 12.

[3] AP-42, Table 3.1-1 infers a control efficiency of 73 pct. for water injection. While 77 pct. was listed in recent Emission Unit Inventory submittals, 73 pct. is used in this analysis. Permit AQ0110TVP03, Condition 13.2 requires water injection for EU IDs 5 and 6.

[4] Total potential emissions have been adjusted to reflect ORL restrictions.

[5] EU ID 7 is limited to operating no more than 52 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 10.

[6] The EU ID 2 regenerative system was rebuilt during 2012-2013 and is expected to be more effective than the regenerative system on EU ID 1 but has not been quantified.

Table 1-4. Significant Emission Unit Potential $PM_{2.5}$ Emissions

Significant Emission Units		Factor	PM Emission	Maximum	Maximum	Regulatory Limits	Existing Control Technology		Potential $PM_{2.5}$
ID	Description	Reference	Factor	Capacity	Operation		Description	Efficiency (pct.)	Emissions
1	Simple Cycle Gas Turbine	AP-42 Table 3.1-2a	0.012 lb/MMBtu	672 MMBtu/hr	8,760 hr/yr	NA	NA		35.3 tpy
2	Simple Cycle Gas Turbine	AP-42 Table 3.1-2a	0.012 lb/MMBtu	672 MMBtu/hr	7,992 hr/yr[1]	NA	Limited Operation	9	32.2 tpy
3	Fuel Storage Tank	NA	NA	50,000 Gallons	8,760 hr/yr	NA	NA		0 tpy
4	Fuel Storage Tank	NA	NA	50,000 Gallons	8,760 hr/yr	NA	NA		0 tpy
5	Combined Cycle Gas Turbine	AP-42 Table 3.1-2a	0.012 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	NA	NA		23.9 tpy
6	Combined Cycle Gas Turbine	AP-42 Table 3.1-2a	0.012 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	NA	NA		23.9 tpy
7	Emergency Generator Engine	AP-42 Table 3.3-1	0.0022 lb/hp-hr	461.6 kW	52 hr/yr[2]	NA	Limited Operation + Positive Crankcase Ventilation	99	0.035 tpy
11	Boiler	AP-42 Table 1.5-1	0.7 $lb/10^3$gal	5.0 MMBtu/hr	8,760 hr/yr	NA	NA		0.2 tpy
12	Boiler	AP-42 Table 1.5-1	0.7 $lb/10^3$gal	5.0 MMBtu/hr	8,760 hr/yr	NA	NA		0.2 tpy
							Total Potential Emissions		115.7 tpy

Sample Calculations:

Turbine Emissions, tpy= (Emission factor, lb/MMBtu) * (Capacity, MMBtu/hr) * (Operation, hr/yr) / (2,000 lb/ton)

Engine Emissions, tpy= (Emission factor, lb/hp-hr) x (Capacity, kW) * (Conversion, 1.341 hp/kW) * (Operation, hr/yr) / (2,000 lb/ton)

Heater (Boiler) Emissions, tpy= (Emission factor, $lb/10^3$gal) * (Conversion, 10^3gal/91.5 MMBtu) * (Capacity, MMBtu/hr) * (Operation, hr/yr) / (2,000 lb/ton)

- Propane heat content is assumed to equal 91.5 MMBtu/10^3 gallon per AP-42 Table 1.5-1.

Notes:

[1] EU ID 2 is limited to operating no more than 7,992 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 12.

[2] EU ID 7 is limited to operating no more than 52 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 10.

Table 1-5. Significant Emission Unit Potential SO_2 Emissions

Significant Emission Units		Factor	Maximum Fuel	SO_2 Emission	Maximum	Maximum	Regulatory Limits	Existing Control Technology		Potential SO_2
ID	Description	Reference	Sulfur Content	Factor	Capacity	Operation		Description	Efficiency (pct.)	Emissions
1	Simple Cycle Gas Turbine	AP-42 Table 3.1-2a	0.50 wt. pct. S[1]	0.51 lb/MMBtu	672 MMBtu/hr	8,760 hr/yr	Permit AQ0110TVP03 Combined emission limit of 24,500 lb/day[1]	NA		1,486.4 tpy[1]
2	Simple Cycle Gas Turbine	AP-42 Table 3.1-2a	0.50 wt. pct. S[1]	0.51 lb/MMBtu	672 MMBtu/hr	7,992 hr/yr[2]		Limited Operation	9	1,356.1 tpy[1]
3	Fuel Storage Tank	NA	NA	NA	50,000 Gallons	8,760 hr/yr	NA	NA		0 tpy
4	Fuel Storage Tank	NA	NA	NA	50,000 Gallons	8,760 hr/yr	NA	NA		0 tpy
5	Combined Cycle Gas Turbine	AP-42 Table 3.1-2a (non-startup)	0.005 wt. pct. S[3]	0.005 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	Subpart GG 150 ppmvd at 1 5 pct. O_2 or 0.8 wt. pct. S	Low Sulfur Fuel (0.05 pct by weight)	N/A	10.1 tpy
		Mass Balance (startup)	0.3 wt. pct. S[4]	0.037 lb/gal		1,500,000 gal/yr		NA		N/A[4]
		Total								10.1 tpy
6	Combined Cycle Gas Turbine	AP-42 Table 3.1-2a (non-startup)	0.005 wt. pct. S[3]	0.005 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	Subpart KKKK 0.9 lb/MWh emissions	Low Sulfur Fuel (0.05 pct by weight)	N/A	10.1 tpy
		Mass Balance (startup)	0.3 wt. pct. S[4]	0.037 lb/gal		1,500,000 gal/yr	Subpart KKKK 0.06 lbSO_2/MMBtu fuel	NA		N/A[4]
		Total								10.1 tpy
7	Emergency Generator Engine	Mass Balance	0.1 wt. pct. S[5]	0.014 lb/gal	32 gal/hr[6]	52 hr/yr[7]	NA	Limited Operation	99	0.01 tpy
11	Boiler	AP-42 Table 1.5-1	0.012 wt. pct. S[8]	0.0012 lb/10^3gal	5.0 MMBtu/hr	8,760 hr/yr	NA	Low Sulfur Fuel (propane - 120 ppmv)	Unknown	0.0003 tpy
12	Boiler	AP-42 Table 1.5-1	0.012 wt. pct. S[8]	0.0012 lb/10^3gal	5.0 MMBtu/hr	8,760 hr/yr	NA	Low Sulfur Fuel (propane - 120 ppmv)	Unknown	0.0003 tpy
									Total Potential Emissions	2,862.6 tpy[9]

Sample Calculations:

Molar mass ratio is 32 lb S/mol : 64 lb SO_2/mol

Stoichiometry: 1 mol S = 1 mol SO_2

Mass Balance Emission Factor, lb/gal = (Molar mass ratio, 2 lb SO_2:1 lb S) * (wt. pct. S in fuel) * (density of fuel, lb/gal) / 100%

Turbine Emissions (Normal Operation), tpy= (Emission factor, lb/MMBtu) * (Capacity, MMBtu/hr) x (Operation, hr/yr) / (2,000 lb/ton)

Turbine Emissions (Startup), tpy= (Emission factor, lb/gal) * (Throughput, gal/yr) / (2,000 lb/ton)

Engine Emissions, tpy= (Emission factor, lb/gal) * (Capacity, gal/hr) * (Operation, hr/yr) / (2,000 lb/ton)

Heater (Boiler) Emissions, tpy= (Emission factor, lb/10^3gal) * (Conversion, 10^3gal / 91.5 MMBtu) * (Capacity, MMBtu/hr) * (Operation, hr/yr) / (2,000 lb/ton)

wt. pct. S (in diesel) = (Sulfur compound emission limit, ppmv SO_2) * (Conversion, 1.66E-7 lb SO_2/scf / ppm SO_2) x (F-factor, 9,190 scf/MMBtu) * (Conversion, 0.0193 MMBtu/lb) * (Conversion, mole SO_2/64 lb SO_2) x (Conversion, mole S/mole SO_2) * (Conversion, 32 lb S/ mole S)

-Turbine startup fuel is assumed to have an average density of 6.2 lb/gal. Emergency generator fuel is assumed to equal 7.1 lb/gal per note (a) of AP-42 Table 3.4-1.

- Propane heat content is assumed to equal 91.5 MMBtu/10^3 gallon per AP-42 Table 1.5-1.

Notes:

[1] EU IDs 1 and 2 can combust No. 1 and No. 2 fuel oil, which (by specification) can have a maximum sulfur content of 0.5 wt. pct. The two emission units may emit no more than 24,500 pounds of SO_2 per day, combined, per Permit AQ0110TVP03, Condition 14. The fuel oil sulfur content specification of 0.5 wt. pct. S is more restrictive. Each unit could be operated individually up to the potential SO_2 emissions shown above.

[2] EU ID 2 is limited to operating no more than 7,992 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 12.

[3] The normal operating fuel for EU IDs 5 and 6 is LSR Naphtha obtained from PSI under a long-term contract. The sulfur content of the LSR is limited to no more than 30 ppmw by the terms of that contract, a small percentage (<2%) of fuel may be made up with other naphtha blends with sulfur content no more than 50 ppmw. A conservative fuel sulfur content of 50 ppm is used for calculating SO_2 emissions from EU IDs 5 and 6.

[4] EU ID 5 is a "base-load" unit that is operated continuously for extended periods of time. EU ID 6, if constructed, will be operated in the same manner. As a result, startups on No. 1 or No. 2 fuel oil are infrequent, so potential emissions from startups are not included.

[5] EU ID 7 is limited to a fuel sulfur content of 0.1 wt. pct per Permit AQ0110TVP03, Condition 9.

[6] The engine specification datasheet indicates a maximum fuel throughput of 32 gal/hr.

[7] EU ID 7 is limited to operating no more than 52 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 10.

[8] EU IDs 11 and 12 are limited to a fuel sulfur content of 0.012 wt. pct. per Permit AQ0110TVP03, Condition 11.

[9] Total potential emissions have been adjusted to reflect annual operating hour restrictions.

Table 1-6. Significant Emission Unit Potential VOC Emissions

Significant Emission Units		Factor	VOC Emission	Maximum	Maximum	Regulatory Limits	Existing Control Technology		Potential VOC
ID	Description	Reference	Factor	Capacity	Operation		Description	Efficiency (pct.)	Emissions
1	Simple Cycle Gas Turbine	AP-42 Table 3.1-2a	0.00041 lb/MMBtu	672 MMBtu/hr	8,760 hr/yr	NA	NA		1.2 tpy
2	Simple Cycle Gas Turbine	AP-42 Table 3.1-2a	0.00041 lb/MMBtu	672 MMBtu/hr	7,992 hr/yr[1]	NA	Limited Operation	9	1.1 tpy
3	Fuel Storage Tank	TANKS 4.0.9d	-	50,000 Gallons	8,760 hr/yr	NA	NA		0.04 tpy
4	Fuel Storage Tank	TANKS 4.0.9d	-	50,000 Gallons	8,760 hr/yr	NA	NA		0.06 tpy
5	Combined Cycle Gas Turbine	AP-42 Table 3.1-2a	0.00041 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	NA	NA		0.8 tpy
6	Combined Cycle Gas Turbine	AP-42 Table 3.1-2a	0.00041 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	NA	NA		0.8 tpy
7	Emergency Generator Engine	AP-42 Table 3.3-1	0.003 lb/hp-hr	461.6 kW	52 hr/yr[2]	NA	Limited Operation	99	0.0 tpy
11	Boiler	AP-42 Table 1.5-1	0.8 lb/10^3gal	5.0 MMBtu/hr	8,760 hr/yr	NA	NA		0.2 tpy
12	Boiler	AP-42 Table 1.5-1	0.8 lb/10^3gal	5.0 MMBtu/hr	8,760 hr/yr	NA	NA		0.2 tpy
							Total Potential Emissions		4.5 tpy

Sample Calculations:

Turbine Emissions, tpy= (Emission factor, lb/MMBtu) * (Capacity, MMBtu/hr) * (Operation, hr/yr) / (2,000 lb/ton)

Engine Emissions, tpy= (Emission factor, lb/hp-hr) * (Capacity, kW) * (Conversion, 1.341 hp/kW) * (Operation, hr/yr) / (2,000 lb/ton)

Heater (Boiler) Emissions, tpy= (Emission factor, lb/10^3gal) * (Conversion, 10^3gal/91.5 MMBtu) * (Capacity, MMBtu/hr) * (Operation, hr/yr) / (2,000 lb/ton)

- Propane heat content is assumed to equal 91.5 MMBtu/10^3 gallon per AP-42 Table 1.5-1.

Notes:

[1] EU ID 2 is limited to operating no more than 7,992 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 12.

[2] EU ID 7 is limited to operating no more than 52 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 10.

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GVEA
Alternative BACT
November 2018

Attachment 2
Technical Memo from PDC Regarding Bulk Fuel Storage

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Transforming Challenges into Solutions

TECHNICAL MEMORANDUM

Client #	PO 201751812	**Date**	June 28, 2017
PDC #	17099FB	**Prepared by**	David Sandberg, EIT, Karen Brady, PE
Project Name	North Pole Fuel Storage Facility	**Reviewed by**	Keith Hanneman, PE
Subject	***Concept Design Alternative Site Layout***		

Topic	Discussion
Summary	The proposed Bulk Fuel Tank Farm and Terminal Facility at the GVEA site in North Pole will provide a dependable fuel source for GVEA's critical power generation operations. The purpose of this technical memorandum is to present the requirements for the facility along with alternatives (including costs) for the site arrangement and recommendation. The various functions of this facility would include storing fuel for the existing power generating systems, with the ability to load and unload fuel from tanker trucks and to unload rail cars on site. It will also provide GVEA with the ability to receive both ultra-low sulfur diesel (ULSD) and QB naphtha from Petro Star to fill the tanks. The facility arrangement will accommodate Interior Gas Utility's (IGU) future needs for liquid natural gas storage, regasification for distribution and GVEA power use. Additionally, it will provide space for a Petro Star rail loading and unloading rack with driveway access to H&H Road and Old Richardson Highway through the GVEA 138 kV right-of-way. This memo was developed based on information provided from the following: • PDC Engineers has developed the site arrangements and general coordination between the various stake holders including GVEA, Petro Star, Alaska Railroad, and Interior Gas Utility (IGU). • Great Northern Engineers (GNE) has developed the design criteria and details for the fuel tanks, containment, controls, pumping, and fuel piping. The costs associated with these items were estimated by GNE. • Shannon & Wilson has provided a soils analysis and general recommendations based on historical data and recent borings. • CHI has provided thermal exclusion zones for the future IGU storage facilities. • HMS, Inc. provided the overall estimate for the three alternatives incorporating the fuel infrastructure pricing that GNE provided, along with additive alternates. Following the review of these concepts with GVEA and consensus on the preferred alternative, the design team may be given notice to prepare construction documents.

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Anchorage, AK 99503
907.743.3200

FAIRBANKS
1028 Aurora Drive
Fairbanks, AK 99709
907.452.1414

JUNEAU
6205 Glacier Highway
Juneau, AK 99801
907.780.6060

PALMER
125 W. Evergreen Avenue,
Suite 102
Palmer, AK 99645
907.707.1215

SOLDOTNA
170 E. Corral Avenue, Suite 2
Soldotna, AK 99669
907.420.0462

General Facility Requirements

The major components of this facility are summarized below. For further details see the attached Basis of Design.

Fuel Storage Tanks

The overall volume for fuel storage is being evaluated by others. Based on the initial evaluation this concept is to provide a total of 3 million gallons (MMG) storage in two tanks. GVEA will have the ability to store either ULSD or QB Naphtha with one tank having a fixed roof and the other a floating roof (as required for QB Naptha).

Based on soils information there is approximately 6 to 10 feet of silt overlying alluvial sands and gravels that would need to be removed and replaced with gravel following deep dynamic compaction beneath the proposed tank foundations.

The tanks would be constructed within a 6- to 7-foot-high containment dike that would hold 110% of the capacity of a single tank plus precipitation and freeboard. They would be surrounded by a 7-foot-tall security fence that would have gated vehicle access.

Fire Suppression

The fuel tanks would be protected from fire with a fire suppression system, as required by the Fire Marshall since each diesel tank will exceed 1,500 SF of surface area (a much smaller 364,000-gallon tank about 44 feet in diameter would have 1,500 SF surface area). This system would consist of aqueous film forming foam (AFFF) water supply lines originating from a room in the Pump Building that would route to shell mounted foam chambers on each tank.

This automated foam system, which will respond when triggered by an alarm, will be housed in the pump building. Additional firefighting infrastructure will be installed around the tank farm, truck rack and rail facility.

Truck Unloading/ Loading

The truck unloading/loading facility would allow for filling or receiving fuel from two A-train double fuel tanker trucks simultaneously at two stations at a maximum rate of 600 gpm per station. It will be a paved surface with a concrete drive-on lane provided with spill containment and drive-off protection. Surface water will be routed to an oil/water separator which would discharge clean water to surface and oily water to the City of North Pole's industrial wastewater line along H&H Road.

Railroad Unloading

A rail spur would be constructed to support the proposed rail rack. This would provide two spurs, with a combined capability of receiving up to 20 23,500-gallon tanker cars. These are the same size cars used for rail distribution at the Flint Hills Terminal Facility. The volume will vary with the site layout, from 423,000 to 470,000 gallons. The rail rack would support unloading ULSD from two rail tanks simultaneously at a maximum rate of 600 gpm. Containment would be provided for potential spills to hold the volume of one car (23,500 gallons).

In order for the rail cars to be positioned for unloading, a Trackmobile would be provided along with a 30'x45' CMU structure for housing it at the end of the spur. The trackmobile would be operated by GVEA. A small, heated, wood-framed structure would be provided for operators unloading train cars to warm up in during the winter.

The cost of the rail tracks is included in the estimates for this project and is broken into GVEA, IGU, and Petro Star Rail facilities.

Fuel Metering and Quality Assurance

Liquid metering systems will be provided for all fuels entering and leaving GVEA custody. Meters will be used to deliver a determined flow rate and comply with standard local and federal codes for fuel handling.

Instrumentation will be Ovation or at least compatible with the existing Ovation Terminal Management System. Meters will be periodically tested with a prover system to ensure they accurately record the quantity of fuels transferred.

Fuels quality can be assured through on-site laboratory analysis. The fuels quality control lab will be located in the control building and have the necessary equipment to verify all fuel cargo and inventory meet the standards required, particularly for low sulfur fuel.

Buildings

A 30'x40' pump house building would be provided to house four centrifugal pumps along with small transfer pumps associated with tank fill/suction, and supply to the fuel transfer facility. It would also contain a pair of filter trains for particulate and water removal for fuels entering and leaving the storage tanks. The building would house two oil water separators. One to treat surface water from the tank containment and unloading facilities. The other to treat water removed from the storage tanks. This building would also house the AFFF support system. The building would be approximately 1,200 sf constructed of CMU block. It would be heated to maintain a comfortable working temperature during the winter utilizing heat from the control building.

The 30'x40' control building would house controls, a single office space, storage dedicated to the maintenance and operation of this facility, and a bathroom. This will be the central point of operation of the facility but will integrate with the facility operations by means of a packaged terminal management system. This building would be similar size and construction to the pump house building.

Exterior Fuel Piping

The fuel piping would be ASTM A53 Gr. B, Sch. 40 steel pipe rated for an ANSI Class 150 system. It would be fabricated and installed in accordance with ASME B31.3 standards for welding and non-destructive examination requirements.

Piping systems shall be buried where appropriate, adequately supported when above ground, and designed to withstand the maximum stresses in accordance with ASME required load combinations such as pressure, thermal expansion, gravity loads and seismic loading.

All piping will include a three-coat exterior field coating consisting of an appropriate epoxy system with a urethane topcoat to prevent chalking and UV degradation.

Security

Physical security would be provided at the facility with a 7-foot chain link fence topped with razor wire to surround the fuel tanks, rail and truck facilities. Access would be provided to vehicles with electronic proximity readers. Building access would also utilize electronic proximity readers and Best type "TC" keying standard.

Tanks will be located to provide separation distances and vegetated buffers. CCTV surveillance would be provided through video monitoring at vehicle gates, building entrances, perimeter fence, pump control rooms, truck unloading area, and rail area. Intrusion detection would be provided using infrared sensors for motion detection in addition to magnetic switches at doors.

Alarming and monitoring will be provided from a central panel to dispatch local police to potential trespassers should an alarm get triggered.

Access Road

A new paved access road to the power plant would allow GVEA to enter the NPEP and NPG property off of H&H Road without going through Petro Star or Flint Hills. The alignment would be south of the existing traveled way to provide a corridor for the fuel piping between the road and the existing infrastructure. It will be a 30-foot wide, paved, and have gated access off of H&H road. This road would also allow access fuel storage in Alternatives 1A and 1B.

Interior Gas Utility Shared Use of Land East of H&H Road

GVEA has committed to shared use of their land east of H&H with IGU to support IGU development of LNG offloading, storage, and re-gasification to support GVEA power generation and IGU's distribution system. To make sure that the alternatives developed for the GVEA fuels were compatible with code/safety requirements, CHI Engineering performed a planning level analysis on the storage volumes required for the following scenarios as discussed during the project kick-off meeting:

1. Short Term: 3 years to support IGU growth into Phases 1-3
   a. Distribution 100 psi maximum – odorized
   b. 150,000 gallon storage (three 75,000 gallon horizontal tanks to provide (N+1))
   c. 5 day storage needed for residential
2. Long Term: After 3 years to meet long-term growth for IGU into Phase 1-3 and GVEA power generation
   a. May want to increase residential to 7 day supply or 300,000 gallons
   b. 700,000 gallons of LNG storage (7 day supply at 100,000 gallons per day) as previously discussed by GVEA as potential.
   c. 1,000,000 gallons of LNG storage for combined GVEA and residential.
3. Ultimate Plan
   a. IGU is required to provide 5 days of storage for firm customers and will work with GVEA on shared storage. As additional IGU customers are added, the storage will increase. Ultimate storage quantity is undefined at this time so it is important to have room for expansion.

Based on the above storage volumes, the offsets required for the 10,000 kBTU/hr/ square foot LNG thermal exclusion zone to property lines or facilities that are not under IGU's control are:

- Short Term 75k Gallon horizontal tanks and LNG unloading station: 184-foot radius
- 1.0 MMG Single Containment: 439' radius
- 1.0 MMG Full Containment: 134' radius

In addition to the tanks, the IGU use will include the "balance of plant," which includes:

- Two low-pressure vaporization trains for distribution
- One high-pressure vaporization train for GVEA powerplant needs
- Truck unloading stations for unloading two trucks simultaneously.
- Plant control building
- boil-off system
- control and hazard detection systems
- send-out metering
- pressure regulation and odorization
- fire protection
- plant utilities
- hazard detection systems.

The planning also included parallel rail spurs to stage railcars for LNG ISO tank offloading. The offset for the railcar unloading to property line and buildings for the 10,000 kBTU/hr/square foot LNG thermal exclusion zone was assumed to be 125 feet but needs detailed coordination with the ARRC before being finalized.

At this planning level, it appears there is sufficient space along the H&H side of the large trapezoidal parcel for the short-term horizontal storage and the balance of plant while allowing room for the future 1MMG single containment storage tank. This is the preferred configuration by IGU as it reduces their development costs.

The final determination of space requirements will require performing a Facility Plan study for the IGU operations at this site. In case the Facility Plan shows that the truck unloading facility or short-term horizontal storage will not fit, the triangle parcel north of the GVEA fuel lines should be reserved for this potential use.

City of North Pole Water Source Protection

The City of North Poles water supply wells are located approximately ¾ of a mile from the proposed fuel facility. Groundwater modeling that was performed for the ADEC Approval to Construct the wells shows that the boundary for the 2-year area of influence crosses through the proposed site. This is shown in the Site Layouts C1-C3.

There are two boundary lines shown on the drawing. The minimum area crosses through the parcel of land east of H&H Road. This assumes that the ground is free of permafrost. The maximum area boundary is located just west of H&H Road. Construction of the fuel storage facility within the area of influence will likely require mitigation to show the City that the wells are protected from potential spills. Additional coordination with ADEC, the City, soil investigation, and groundwater modeling would be needed for placement of tanks within this area. Also, additional soil testing may be required to verify if permafrost is present within the area of influence.

Alternatives

Three alternatives were developed to evaluate the best use of space. The alternatives are described below and shown in attached Site Layouts C1-C3. The cost breakdowns

are also attached. Based on the estimates, there is only a 2% difference in cost associated with the alternatives; therefore they should be considered equal at this stage. There is a 50% contingency included in the costs for budgeting.

Alternative 1 ***Fuel Storage Tanks West of H&H Road***

The Tank Farm is sited west of H&H Road and located inside a perimeter that is already fenced. Pump and control buildings are located adjacent to tank farm. The rail facility is located east of H&H. The future peaker plant may be located north of the future rail facility, and future fuels expansion would be possible adjacent to Old Richardson Hwy.

There are two variations with this alternative. In **Alternate 1A** the truck facility would be located adjacent to the fuel facility on the west side of H&H Road and would require the purchase of additional land from Flint Hills. In **Alternative 1B** the tanks would be rotated 90° to keep them within the limits of GVEA property and the truck facility would be located on the east side of H&H Road.

- Cost: $26,800,000
- Pros
  - Tanks (and truck facility in Alt 1A) would be located away from future IGU infrastructure reducing impacts associated with those unknowns
  - Maintains all future items east of H&H Road
  - Fuel storage tanks would be located outside of the 2-year area of influence for the City of North Poles water supply wells.
- Cons
  - Property must be acquired from Flint Hills Resources (FHR) for Alt 1A
  - No room for future fuels storage west of H&H
  - Cold storage tent demolition required for construction of the tanks
  - Potential demolition of existing FHR structures and obstructions requirement (foundations, abandoned piping, conduit, pavement, etc.)

Alternative 2 ***Fuel Storage Tanks East of H&H Road***

Tank Farm is sited east of H&H Road, north of rail facilities. Pump and control buildings are located in-between the tank farm and H&H. The future peaker plant may be located west of H&H, closer to the North Pole Expansion Plant , and future fuels expansion would be possible adjacent to Old Richardson Hwy.

- Cost: $26,500,000
- Pros
  - All existing and future power generation occurs west of H&H Road; would allow for future Peaker Plant to be near other turbine plants
  - No additional property acquisition from FHR required
  - One less pipe crossing H&H Road
  - Room for additional fuels storage. If the tank farm needed additional capacity in future the tanks would be grouped together and could share spill containment/drainage, fire suppression, piping, etc.
  - Cold Storage Building demolition not required for fuel storage construction

- Cons
  - Less efficient tank farm dimensions to fit site
  - Truncated north GVEA rail spur to site Tank Farm (2 less rail cars)
  - More congestion sharing space with Petro Star & IGU
  - Potentially increased soils improvement requirement
  - Mitigation will likely be required to protect City of North Poles water supply wells.

Alternative 3 ***Fuel Storage Tanks Adjacent to Old Richardson Highway***

Similar to Alternative 2, Tank Farm is sited east of H&H Road, north of rail facilities. Pump and control buildings are located in-between the tank farm and H&H. Future peaker plant may be located west of H&H, closer to the North Pole Expansion Plant, and more convenient future fuels expansion would be possible to the west of the Tank Farm.

- Cost: $27,400,000
- Pros
  - Similar to Alternative 2, as all power generation occurs west of H&H Road and Cold Storage does not require demolition for fuel storage construction,but allows easier access for future construction equipment if additional tanks were added and is more flexible if desired tank size increases.
  - Simplifies access to Petro Star Rail Facility
  - Does not bottleneck future development of GVEA land from the west
- Cons
  - Less efficient tank farm dimensions to fit site
  - Greater earthwork requirement for deeper overburden on east side of site
  - Potentially increased soils improvement requirement
  - Greater length of piping than Alternative 2
  - Mitigation will likely be required to protect the City of North Poles water supply wells.

Recommendation

Each alternative is technically viable; however Alternative 1 would keep the fuel storage tanks out of the City of North Poles 2-year Area of Influence which would simplify the permitting process.

Alternative 1A would keep all future facilities east of H&H allowing for the need, sizing, and layout to be further developed with little impact to the storage facility. The other alternatives do not have any significant operational or future expansion benefits. There is also a chance that the peaker plant may not be installed in North Pole. In the event that GVEA wants it to be closer to the other generation facilities in North Pole there is a possibility of that to be installed east to of the Old Turbine Building.

Attachments

1. Basis of Design
2. Alternative Site Layouts
3. Piping Schematics
4. Tank Flow Diagram
5. Fuel Piping List
6. Soils Report
7. CHI LNG Memo
8. Cost Estimate

Transforming Challenges into Solutions

TECHNICAL MEMORANDUM

Client #	PO 201751812	**Date**	June 28, 2017
PDC #	17099FB	**Prepared by**	David Sandberg, EIT, Karen Brady, PE
Project Name	North Pole Fuel Storage Facility	**Reviewed by**	Keith Hanneman, PE
Subject	***Basis Of Design***		

Topic	Discussion
Introduction	The purpose of this technical memorandum is to present the basis of design for the proposed North Pole Fuel Storage Facility.

Design Criteria

- API-650 Standard, *Welded Tanks for Oil Storage*
- ASME B31.3, *Process Piping*
- NFPA 59A
- 2012 IFC
- ADEC
- 2015 IBC
- AASHTO
- ADOT&PF Driveway Standards
- Alaska Railroad – *Technical Standards for Roadway, Trail, and Utility Facilities in the ARRC Right of Way*
- MUTCD 2016 Edition – *Manual on Uniform Traffic Control Devices*
- City of North Pole standards and ordinances
- 49CFR Part 193 Liquefied Natural Gas Facilities: Federal Safety Standards

Fuel Storage Tanks

Size

- Two (2) 36,000 bbl welded steel tanks, for a total storage capacity of 3 million gallons
- Constructed in accordance with the API-650 Standard, *Welded Tanks for Oil Storage*
- 85 feet in diameter and 40 feet tall.
- 36-foot nominal fill height

Configuration

- One (1) internal floating-roof tank for storing more volatile QB Naphtha which Petro Star currently supplies to GVEA. This will prevent vapor emissions from exiting the tank for product conservation and air quality and safety.
- One (1) external fixed-roof tank will store ULSD,
- The construction scope for the tanks would include fabrication, delivery, erection, non-destructive examination, internal appurtenances, hydrostatic testing, and field coating of the tank interior bottom and exterior.
- The tanks would be entirely field fabricated, although shell plates could be rolled, sandblasted and primed prior to delivery to the job site. Field striping of shell welds and final coatings would be performed after erection.
- The Contractor would erect the tanks on the already completed foundations and corrosion protection beds.

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Topic	Discussion

- Appurtenances for the tanks would consist of cargo and service nozzles, water draw-off system, auto gauge level controls, level switches for overfill prevention and pump protection, pressure/vacuum conservation venting, shell mounted AFFF supports, and double block and bleed plug valves on cargo and service tank nozzles.

Foundations

- Soil conditions and geotechnical engineer's recommendation, based on the tank loads, will govern. (See attached "Geotechnical Findings Report.")
- As is common in the Fairbanks area, proposed sites have significant liquefaction hazard, primarily loss of shear strength and settlement during seismic events, due to unconsolidated alluvial deposits at depth.
- Site preparation for all structures will require removal of surficial silty frost susceptible soils and replacement with compacted structural fills.
- Ground improvement will include the entire structure footprint and extend out beyond the outside edge of all foundations a minimum of 25 feet.
- Depth of ground improvement is between 30 to 35 feet below grade.
- Deep dynamic compaction (DDC) is recommended for ground improvement.
- Consider future site expansion/development when defining limits of ground improvement.
- Consider ground improvement during periods of low groundwater to maximize depth of improvement (spring, typically).
- Excavation for tank foundations assumes 10 feet of native soils will be removed and NFS structural backfill imported, per geotechnical report.
- Tank foundations would be nominally 5 feet deep concrete ring wall and be constructed in a typical stem ring wall/footer configuration.
- Tank foundation will have significant amounts of steel reinforcement (typical)
- Tank stem walls will be nominally 16 to 20 inches thick with footers that are approximately 6 feet wide (typical)
- Given the ratio of the height to diameter tank anchoring to the foundation is likely not required.

Setbacks

- Minimum distance to nearest property line that is or can be built upon including the opposite side of a public way: 1/2 tank diameter or 42.5 feet
- Minimum shell-to-shell tank spacing: 1/6 times sum of adjacent tank diameters or 28.5 feet
- Setback from tank and rail car loading/offloading to tanks, buildings, property lines: 25 feet
- Minimum distance from nearest side of any public way or from nearest important building on the same property: 14.17'
- Construction and maintenance clearances: Minimum 20 feet clear between the tank shell and inside toe of the adjacent dike walls is desirable.
- Homeland Security does not have criteria that apply to this facility. However, the site arrangement will be sent for review.

Topic	Discussion
	• General setbacks used for the alternatives match those used by Flint Hills on the adjacent property. ***Containment*** • The tanks would be constructed within an earthen containment dike that is capable of holding a minimum of 110% of the largest tank volume in the event of a release, with an allowance for local precipitation and freeboard. • The containment area would allow for controlled drainage via a subgrade collection system consisting of catch basins, perforated pipe within the porous backfill, and heat traced arctic pipe routed to a central Oily Water Separator (OWS) which also will handle oily water from the rail and truck loading racks before discharging into the city sewer system. • The berm is assumed to be constructed to approximately 6-7 feet above tank farm finished grade. • The berm would have a minimum 3-4 foot flat top (10 feet desirable for ease of construction and maintenance) where the containment liner membrane would be anchored. • This berm would have an outside toe to toe dimension of approximately 28 feet at a 2H:1V slope, which is suitable to maintain vegetation • The containment dike will be underlain with a geo-membrane that is impervious to the petroleum products being stored. The geo-membrane liner will be seam welded and would be installed with a layer of bedding sand and geotextile protective fabric on either side to prevent tearing or puncturing the liner during installation or compaction efforts. The liner would be continuous underneath the tank ring wall foundations. • Tank foundations would be constructed with a separate membrane underneath and within them. This would contain a tank bottom leak inside the foundation system without impacting the rest of the site. • A leak detection system within the foundation containment will allow for notification if a tank leak has occurred. • Excavation for areas not directly underneath tanks is assumed to require the removal of 4 feet of native soils. A geotextile liner will be installed with a minimum 12 inches of bedding material above and below it for protection ***Corrosion Protection*** • Sacrificial anode grid system installed in the bedding beneath each tank to protect the underside from corrosion by means of an impressed current system that requires an external power supply and a rectifier. This is the most common system utilized for tanks of this size and type • Tanks will be externally coated with a three component coating system consisting of prime, intermediate, and top coat. The first two coats are assumed to be a polyamide epoxy and the top coat, polyurethane to prevent chalking of the epoxy when exposed to UV light for extended periods of time. ***Testing*** • The tanks would be hydrostatically tested with water in accordance with API 650 prior to turn over to the Owner.

Topic	Discussion
	• This water will require a permit from ADEC and the City in order to discharge it to the city sewer system.
Rail Offloading	***Rate*** • 600 gallons of ULSD per minute per railcar • Ability to unload two rail cars simultaneously ***Rail Spurs*** • Based on 55'-7-1/8" Tanker Cars (23,500 gallons per car) used at FHR • No. 11 switch from main railroad track • No. 9 switches on rail spurs • Parallel rail spurs to stage railcars for the offloading process. • Gated at eastern end of primary GVEA rail spur • Capacity for 20 railcars in Alternatives 1 & 3 • Reducedcapacity 18 railcars in Alternative 2 ***Rail Unloading Rack*** • Heated building for personnel and fuels equipment and metering/operations • Design spill containment: 30,000 gallons • Trackmobile used to stage railcars during unloading operations • Heated building at west end of rail spur for Track mobile storage and maintenance • Capacity of 470,000 gallons of fuel per delivery in Alternatives 1 & 3 • Capacity of 423,000 gallons of fuel per delivery in Alternative 2 ***Piping*** • One directional flow from unloading rack • Process piping will run between the rail spur with inlet points directed to each of the two rail spur lines. • Avoid running pipes beneath rails if possible • Multiple 10-inch pipelines from rail rack to filtration equipment for redundancy. • All fuel received will pass through filtration equipment consisting of particulate filters prior to entering the storage tanks. ***Oily Water Collection System*** • System of sumps beneath rail unloading rack will collect spills and pass through a central OWS which also will handle oily water from tank farm and truck loading racks before discharging into the industrial wastewater line along H&H Road. ***Trackmobile Building (New)*** • The Trackmobile building will be an approximately 30'x45' structure with a concrete slab on grade capable to support the weight of the Trackmobile unit. • The walls will be CMU block. • Eave height will be approximately 18 feet to allow for an approximate 14'Wx16'H overhead door. • Roof to be wood trusses on 3:12 pitch. • Install 2-ton underhung trolley

Topic	Discussion
	• Building heat to come from shared heat of Control Room Building and Pump House Building ***GVEA Rail Facility Warm-Up Hut (New)*** • Warm-up hut to be 8'x12' wood framed building with concrete slab on grade floor • Walls to be supported by thickened edge slab • Eave height will be approximately 8' • Roof will consist of wood trusses with 4:12 pitch • Building will have single man door and three windows on non-door walls • Building to have electric heat
Truck Loading and Unloading	***General Description*** • Designed to accommodate two (2) "A-Train" double fuel tanker truck configurations for both fuel loading/unloading simultaneously at 600 GPM each • 40 foot minimum turning radius • Two fueling positions for ULSD. Naphtha will not be sent or received by truck. • Currently we have the costs captured to: 1) Offload two tankers simultaneously. 2) Load two tankers simultaneously 3) Offload and load two tankers simultaneously with the same product. • Located adjacent to a concrete drive-on lane, that is depressed in its center to provide the code required containment during transfers. • This concrete slab would be heat traced to allow removal of ice in winter. Waste heat with heating source will be used. • Sump will connect to oily water collection system, pass through a central OWS, which also connects to the tank farm and the rail rack, and then discharge into the industrial wastewater line along H&H Road. • The truck loading rack would not be covered and no structure is included. • The system would contain the necessary primary and secondary shutoff valves, metering, overfill prevention system, drive-off protection, and terminal management system. • Each loading station on the truck loading rack would consist of a meter with a totalizer and reset. • A flow control valve would be used to control the flow into the tanker trucks to a set point and would provide the dead-man shutoff point. ***Loading*** • Loading product will be drawn from the respective tank, through a service header pipeline and into the suction of the diesel supply pumps located in the pump building. The fuel will be pumped to the Truck Loading Rack. • The system would also include an overfill prevention system. We have assumed that vapor recovery is not required, and do not believe that it is due to the relatively small throughput planned for the facility • Two loading arms ***Offloading***

Topic	Discussion
	• Offloading would consist of a 4-inch hose feeding an 8-inch pipeline that leads into the suction of the offloading pump in the pump building.
Waste Heat	• To add efficiencies into this project, waste heat from NPEP will be used to heat structures and the truck loading slab, with secondary source to be used when the turbines are not in operation.
Facility Buildings	***Pump House/Filtration Building*** • 30'x40' CMU block with metal roof, insulated and heated • Waste heat used as primary heat source with backup secondary source • Clearance to other structures: Minimum 25 feet from loading/unloading racks and 14.17 feet from the tanks • Parking for maintenance staff • Foundation designed to contain fuel releases and drain them to a common collection area with the associated alarms to notify the facility operators. • Overhead door • Four (4) large centrifugal pumps, along with smaller transfer pumps with a combined horsepower of nominally 250 HP. • Steel piping, small volume product recovery system, valves, and vessels • A pair of filter trains located within the building to provide particulate and water removal as needed for incoming and outgoing fuel. • Overhead crane rail for equipment maintenance • Structural access walkways • Lighting and Equipment power • Ventilation • AFFF fire suppression system equipment • Controls suitable for use in a hazardous environment • All other associated services necessary to ensure safe and reliable function and access for maintenance and operations. ***Control Building (Controls, AFFF, Maintenance, and Storage Building)*** • 30'x40' CMU block with metal roof, insulated and heated • Waste heat used as primary heat source with backup secondary. • Clearance to other structures: Minimum 25 feet from loading/unloading racks and 14.17 feet from the tanks • Parking for office and maintenance staff • Single office shared fuels control room • Single unisex bathroom • Water, sewer, and electrical service • Heated fueling support equipment storage with overhead door • Mechanical room • Concrete foundation that is designed to suit the soil conditions and is based on the outcome of the geotechnical soils report. Spread Footing and stem wall on improved ground located below frost line is typical. • The offices would be finished in typical office environment fashion and in

Topic	Discussion
	accordance with the occupancy requirements determined by the International Building Code, and will contain document storage • The shop and storage areas of the building would consist of relatively unfinished interiors typical of maintenance and storage shops in arctic environments, and will contain spare parts associated with the facility • The fuel quality control lab would have the necessary ventilation hoods, and the necessary lab equipment would be adequately supported by the building infrastructure, i.e. power, lighting, heat, and ventilation.
Fuel Metering and Quality Assurance	• Liquid metering systems will be provided for all fuels entering and leaving GVEA custody. Meters will be used to deliver a determined flow rate and comply with standard local and federal codes for fuel handling. • Instrumentation will be Ovation or compatible with Ovation as part of the Terminal Management System. Meters will be periodically tested with a prover system to ensure they accurately record the quantity of fuels transferred. • Fuels quality will be assured through on-site laboratory analysis. The fuels quality control lab will be located in the control building and have the necessary equipment to verify all fuel cargo and inventory meet the standards required, particularly for low sulfur fuel.
Fuel Piping	• See attached pipe schedule. • All fuel piping will be ASTM A53 Gr. B, Sch. 40 steel pipe rated for an ANSI Class 150 system. • Piping will be fabricated and installed in accordance with ASME B31.3 standards for welding and NDE requirements. • All piping will include a three (3) coat exterior field coating consisting of an appropriate epoxy system with a urethane topcoat to prevent chalking and UV degradation where exposed. • Cathodic protection will be provided. The selection will take into account the proximity of existing piping and its interaction. This will likely be a passive anode system. • Piping systems shall be buried where appropriate, adequately supported when aboveground, and designed to withstand the maximum stresses in accordance with ASME required load combinations such as pressure, thermal expansion, gravity loads and seismic loading. • Pipe Slopes – o Fuel piping will be graded to slope towards drain points for defueling lines for maintenance where possible. o Offloading piping will be sloped towards pump to allow for system clearing between cargo deliveries. o AFFF piping shall be sloped to meet code with low point drains.
Security	***Access Control – Physical and Electronic*** • Chain link fence with minimum fabric height of 7 feet around tank farm, rail and truck facility. All perimeter fence shall be topped with razor wire.

Topic	Discussion
	• Crash barriers as required by industry best practices • Powered gates will be provided at all access points to tank farm, truck and rail facility, and North Pole Expansion Plant Campus • Personnel gates • Door Hardware – Best type "TC" keying standard • Electronic access at building entrances: Proximity – close read which is currently used at GVEA. • Electronic access at vehicle gates: Proximity – large gap read range which is currently used at GVEA. • Electronic access at locations where additional verification level is desired: Proximity with PIN to open the door without an alarm. ***CCTV Surveillance*** • 4 Megapixel video monitoring at vehicle gates, building entrances, pump control rooms, perimeter fence, truck loading area, and at the tank farm near controls and valves • 3-7 day local video storage if central connection disrupted • Centralized security monitoring office located in the Illinois Street headquarters campus with redundant monitoring available at North Pole Expansion Plant. • Central storage facility that is expandable • Duration of video saved: 30 days ***Intrusion Detection*** • Perimeter motion detection (infrared) • Wide gap balanced magnetic switches used at gates and overhead doors which are less susceptible to spoofing • Magnetic door contracts for interior applications • Motion detection (Infrared) used as backup for magnetic door contracts ***Alarming and Monitoring*** • Central alarm • Central logging • Remote alarm monitoring; since the facility is monitored remotely, this is preferred to dispatch police to detain potential trespassers.
Electrical	• The largest facility loads will be the fuel transfer pumps located in the pump building. • Facility lighting would be installed to provide illumination necessary for operators to have safe access for maintenance and routine functions. • All lighting would likely utilize LED fixtures and will strictly adhere to dark-sky requirements and airport regulations. • Below-grade conduit runs will be routed from the tank farm electrical to a main distribution point at a location to be determined. • Hazardous Area Classification will need to be defined and the device ratings would comply with the NEC regulations relative to their locations.

Topic	Discussion
Controls	• Controls shall be integrated into the facility operations by means of a packaged Terminal Management System (TMS) compliant with the current Ovation system in operation at GVEA. • Any auxiliary controls required to control functions unique to the fuels facility is assumed to be compatible with the existing Ovation system. • Electrical controls required for the tank farm include data transmission from the tank auto gauge system, level and pump flow switches, and alarms. • Additional tank alarms will consist of a high-high level alarm, low level alarm and level indication based on the gauging system. • The conduit, devices and wiring required for the installation will be listed intrinsically safe in accordance with NEC requirements.
Fire Suppression	• Fire Marshal requires that any diesel tank that exceeds 1500 SF (a 364,000 gallon tank about 44 feet diameter) of fuel surface area requires an AFFF system. • Aqueous Film Forming Foam (AFFF) system will be supplied and housed in the Control Building. • The system will be automated. • The AFFF system would consist of foam water supply pipelines that originate in the AFFF room of the Control Building and are routed to shell mounted foam chambers on each tank. • The AFFF supply manifold, located in the AFFF building, would be designed for the future expansion and have provisions for the new supply lines to any new tanks. • The pipe would be painted galvanized steel. All piping would be constructed in accordance with industry standards for welding and NDE requirements. • The piping would be supported from the tank shell as required with welded tabs installed by the tank fabricator. • All piping would also include a three-coat exterior field coating consisting of an appropriate epoxy system with a urethane topcoat to prevent chalking and UV degradation. • The perimeter AFFF system would consist of foam water supply pipelines that originate in the pump house building and are routed around the perimeter of the tank farm on the outside of the dike. • Hose connection points are located nominally every 200’ to allow for fire department connection in fighting tank fires from outside the containment area. • The piping would be supported on vertical supports as required along the dike.
Access Road	• New access road would allow GVEA to enter the NPEP and NPG from H&H Road without having to drive through Flint Hills or Petro Star. • Required to be built for Alternatives 1A and 1B • Not necessary to construct fuel storage for Alternatives 2 and 3 • Alignment chosen will provide room for a piping corridor between the road and existing infrastructure on the north. • 30-foot-wide paved access road west of H&H to GVEA North Pole Expansion Plant

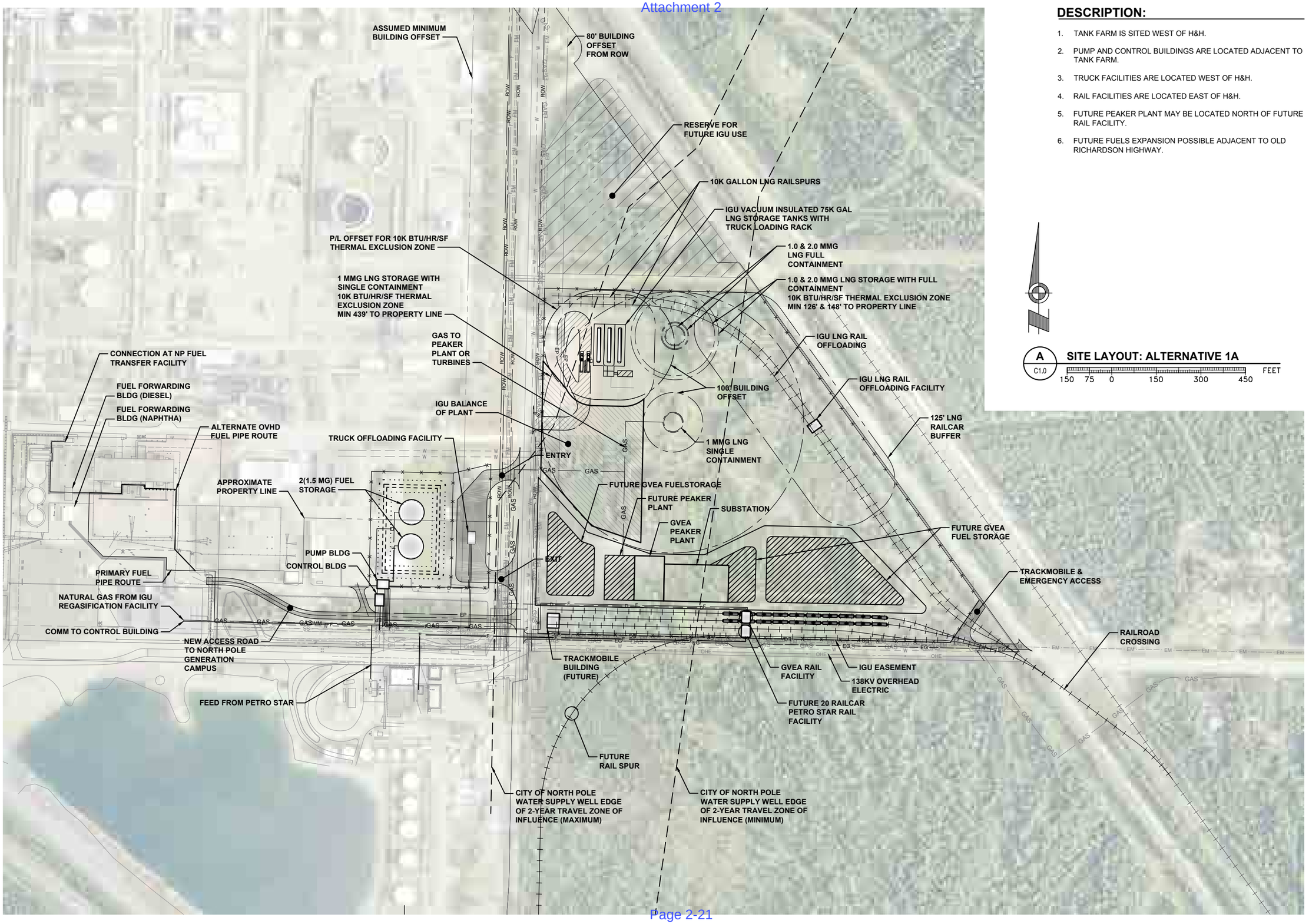
Topic	Discussion
	• Connects H&H to northwest corner of North Pole Expansion Plant yard • Gated at H&H Road
Future Peaker Plant	• Future Peaker Plant has been considered in all conceptual site layouts. ***Potential Location*** • North Pole Generation Campus and Illinois St. Campus have been considered for Peaker plant location. ***Sizing*** • Peaker plant size based on Four (4) Wärtsilä units • Future peaker plant expansion based on another Four (4) Wärtsilä units • Additional space allocated for future Peaker Plant expansion • Substation size is based on other substations located nearby ***Fuel Consumption Rates*** • ULSD: 580 gallons/hr/Wärtsilä unit • Natural Gas: 70,000 scf/hr @ 85 psig + 6 gallons ULSD/hr/Wärtsilä unit
IGU	***LNG Storage Needs*** • Short Term (3 years for phases 1-3): ..... 150k Gallon Storage • Long Term (>3 years to meet long term growth): .. 700k Gallon Storage • Ultimate: 1.0 MMG Storage ***Offsets to Property Line and Buildings for 10,000 BTU/hr/square foot LNG Tank Thermal Exclusion Zone*** • Short Term 75k Gallon horizontal tanks with N+1 Availability: 184-foot radius • 1.0 MMG Single Containment: ..... 439' radius • 1.0 MMG Full Containment: ..... 134' radius ***Future Rail Unloading Facility*** • Parallel rail spurs to stage railcars for the LNG offloading process. • Gated at southern end of primary IGU rail spur • Shared road crossing with GVEA and Petro Star rail facilities • Offset from railcar to property line and buildings for 10,000 BTU/hr/square foot LNG tank thermal exclusion zone: 184 feet
Petro Star	***Pipelines*** • Existing Naphtha to GVEA • 10-inch steel pipeline from Petro Star to GVEA Fuel Forwarding building • Future pipeline to Petro Star Rail Loading Facility ***Future Rail Loading*** • Parallel rail spurs to stage railcars for loading and unloading 20 rail cars • Gated at eastern end of primary Petro Star rail spur • Shared road crossing with GVEA and IGU rail facilities
Soils and	• Relatively flat terrain

Topic	Discussion
Topography	• 2-10 feet of silty soils underlain with sandy gravel and gravels at depth. • High groundwater table, 2-12 feet BGS • High potential for liquefaction settlement during seismic event • No permafrost encountered in preliminary soils exploration

Attachments:

1. Piping Schedule by GNE

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DESCRIPTION:

1. TANK FARM IS SITED WEST OF H&H.
2. PUMP AND CONTROL BUILDINGS ARE LOCATED ADJACENT TO TANK FARM.
3. TRUCK FACILITIES ARE LOCATED WEST OF H&H.
4. RAIL FACILITIES ARE LOCATED EAST OF H&H.
5. FUTURE PEAKER PLANT MAY BE LOCATED NORTH OF FUTURE RAIL FACILITY.
6. FUTURE FUELS EXPANSION POSSIBLE ADJACENT TO OLD RICHARDSON HIGHWAY.

A C1.0 **SITE LAYOUT: ALTERNATIVE 1A**

150 75 0 150 300 450 FEET

CONSULTANT :

PDC ENGINEERS
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PROJECT :
GOLDEN VALLEY ELECTRIC ASSOCIATION
3M GALLON STORAGE TANK FOR NORTH POLE GENERATION CAMPUS
NORTH POLE, ALASKA

SHEET TITLE :
SITE LAYOUT
ALTERNATIVE 1A
CONCEPT DEVELOPMENT

DESIGN	DES
DRAWN	RJP
CHECKED	KAB
DATE	JUNE 28, 2017

PROJECT No. 17099FB

SHEET NUMBER C1.0 OF . SHEETS

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5. FUTURE FUELS EXPANSION POSSIBLE ADJACENT TO OLD RICHARDSON HIGHWAY.

A C1.1 **SITE LAYOUT: ALTERNATIVE 1B**

150 75 0 150 300 450 FEET

ASSUMED MINIMUM BUILDING OFFSET
80' BUILDING OFFSET FROM ROW
RESERVE FOR FUTURE IGU USE
10K GALLON LNG RAILSPURS
IGU VACUUM INSULATED 75K GAL LNG STORAGE TANKS WITH TRUCK LOADING RACK
P/L OFFSET FOR 10K BTU/HR/SF THERMAL EXCLUSION ZONE
1.0 & 2.0 MMG LNG FULL CONTAINMENT
1 MMG LNG STORAGE WITH SINGLE CONTAINMENT 10K BTU/HR/SF THERMAL EXCLUSION ZONE MIN 439' TO PROPERTY LINE
1.0 & 2.0 MMG LNG STORAGE WITH FULL CONTAINMENT 10K BTU/HR/SF THERMAL EXCLUSION ZONE MIN 126' & 148' TO PROPERTY LINE
GAS TO PEAKER PLANT OR TURBINES
IGU LNG RAIL OFFLOADING
CONNECTION AT NP FUEL TRANSFER FACILITY
FUEL FORWARDING BLDG (DIESEL)
FUEL FORWARDING BLDG (NAPHTHA)
100' BUILDING OFFSET
IGU LNG RAIL OFFLOADING FACILITY
IGU BALANCE OF PLANT
125' LNG RAILCAR BUFFER
ALTERNATE OVHD FUEL PIPE ROUTE
1 MMG LNG SINGLE CONTAINMENT
ENTRY
APPROXIMATE PROPERTY LINE
2(1.5 MG) FUEL STORAGE
TRUCK OFFLOADING FACILITY
FUTURE PEAKER PLANT
SUBSTATION
GVEA PEAKER PLANT
FUTURE GVEA FUEL STORAGE
PUMP BLDG
EXIT
TRACKMOBILE & EMERGENCY ACCESS
PRIMARY FUEL PIPE ROUTE
NATURAL GAS FROM IGU REGASIFICATION FACILITY
COMM TO CONTROL BUILDING
NEW ACCESS ROAD TO NORTH POLE GENERATION CAMPUS
CONTROL BLDG
TRACKMOBILE BUILDING (FUTURE)
RAILROAD CROSSING
GVEA RAIL FACILITY
IGU EASEMENT
138KV OVERHEAD ELECTRIC
FEED FROM PETRO STAR
FUTURE 20 RAILCAR PETRO STAR RAIL FACILITY
FUTURE RAIL SPUR
CITY OF NORTH POLE WATER SUPPLY WELL EDGE OF 2-YEAR TRAVEL ZONE OF INFLUENCE (MAXIMUM)
CITY OF NORTH POLE WATER SUPPLY WELL EDGE OF 2-YEAR TRAVEL ZONE OF INFLUENCE (MINIMUM)

CONSULTANT :

PDC ENGINEERS
PLAN • DESIGN • CONSTRUCT
1028 Aurora Drive, Fairbanks, Alaska 99709
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PROJECT :
GOLDEN VALLEY ELECTRIC ASSOCIATION
3M GALLON STORAGE TANK FOR NORTH POLE GENERATION CAMPUS
NORTH POLE, ALASKA

SHEET TITLE :
SITE LAYOUT
ALTERNATIVE 1B
CONCEPT DEVELOPMENT

DESIGN	DES
DRAWN	RJP
CHECKED	KAB
DATE	JUNE 28, 2017

PROJECT No. 17099FB

SHEET NUMBER C1.1 OF . SHEETS

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DESCRIPTION:

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2. PUMP AND CONTROL BUILDINGS ARE LOCATED IN-BETWEEN THE TANK FARM AND H&H.
3. TRUCK AND RAIL FACILITIES ARE LOCATED EAST OF H&H.
4. FUTURE PEAKER PLANT MAY BE LOCATED WEST OF H&H, CLOSER TO THE NORTH POLE EXPANSION PLANT.
5. FUTURE FUELS EXPANSION POSSIBLE ADJACENT TO OLD RICHARDSON HIGHWAY.

A C2.0 **SITE LAYOUT: ALTERNATIVE 2**

150 75 0 150 300 450 FEET

ASSUMED MINIMUM BUILDING OFFSET
80' BUILDING OFFSET FROM ROW
RESERVE FOR FUTURE IGU USE
10K GALLON LNG RAILSPURS
IGU VACUUM INSULATED 75K GAL LNG STORAGE TANKS WITH TRUCK LOADING RACK
P/L OFFSET FOR 10K BTU/HR/SF THERMAL EXCLUSION ZONE
1.0 & 2.0 MMG LNG FULL CONTAINMENT
1 MMG LNG STORAGE WITH SINGLE CONTAINMENT 10K BTU/HR/SF THERMAL EXCLUSION ZONE MIN 439' TO PROPERTY LINE
1.0 & 2.0 MMG LNG STORAGE WITH FULL CONTAINMENT 10K BTU/HR/SF THERMAL EXCLUSION ZONE MIN 126' & 148' TO PROPERTY LINE
IGU LNG RAIL OFFLOADING
CONNECTION AT NP FUEL TRANSFER FACILITY
FUEL FORWARDING BLDG (DIESEL)
FUEL FORWARDING BLDG (NAPHTHA)
ALTERNATE OVHD FUEL PIPE ROUTE
100' BUILDING OFFSET
IGU LNG RAIL OFFLOADING FACILITY
IGU BALANCE OF PLANT
125' LNG RAILCAR BUFFER
FUTURE PLANT EXPANSION
GAS TO PEAKER PLANT OR TURBINES
1 MMG LNG SINGLE CONTAINMENT
GVEA PEAKER PLANT
ENTRY
100' BUILDING OFFSET
APPROXIMATE PROPERTY LINE
CONTROL BLDG
PUMP BLDG
SUBSTATION
TRUCK OFFLOADING FACILITY
2(1.5 MG) FUEL STORAGE
PEAKER PLANT ACCESS
FUTURE GVEA FUEL STORAGE
TRACKMOBILE & EMERGENCY ACCESS
PRIMARY FUEL PIPE ROUTE
EXIT
NATURAL GAS FROM IGU REGASIFICATION FACILITY
RAILROAD CROSSING
COMM TO CONTROL BUILDING
NEW ACCESS ROAD TO NORTH POLE GENERATION CAMPUS
TRACKMOBILE BUILDING (FUTURE)
GVEA RAIL FACILITY
IGU EASEMENT
138KV OVERHEAD ELECTRIC
FEED FROM PETRO STAR
FUTURE 20 RAILCAR PETRO STAR RAIL FACILITY
FUTURE RAIL SPUR
CITY OF NORTH POLE WATER SUPPLY WELL EDGE OF 2-YEAR TRAVEL ZONE OF INFLUENCE (MAXIMUM)
CITY OF NORTH POLE WATER SUPPLY WELL EDGE OF 2-YEAR TRAVEL ZONE OF INFLUENCE (MINIMUM)

CONSULTANT :

PDC ENGINEERS
PLAN • DESIGN • CONSTRUCT
1028 Aurora Drive, Fairbanks, Alaska 99709
907.452.1414 | AECC605

PROJECT :
GOLDEN VALLEY ELECTRIC ASSOCIATION
3M GALLON STORAGE TANK FOR NORTH POLE GENERATION CAMPUS
NORTH POLE, ALASKA

SHEET TITLE :
SITE LAYOUT ALTERNATIVE 2
CONCEPT DEVELOPMENT

DESIGN	DES
DRAWN	RJP
CHECKED	KAB
DATE	JUNE 28, 2017

PROJECT No. 17099FB
SHEET NUMBER C2.0
OF . SHEETS

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DESCRIPTION:

1. SIMILAR TO ALTERNATIVE 2, TANK FARM IS SITED EAST OF H&H.
2. PUMP AND CONTROL BUILDINGS ARE LOCATED IN-BETWEEN THE TANK FARM AND H&H.
3. TRUCK AND RAIL FACILITIES ARE LOCATED EAST OF H&H.
4. FUTURE PEAKER PLANT MAY BE LOCATED WEST OF H&H, CLOSER TO THE NORTH POLE EXPANSION PLANT.
5. FUTURE FUELS EXPANSION POSSIBLE TO THE WEST OF THE TANK FARM.

A C3.0 **SITE LAYOUT: ALTERNATIVE 3**

150 75 0 150 300 450 FEET

ASSUMED MINIMUM BUILDING OFFSET
80' BUILDING OFFSET FROM ROW
RESERVE FOR FUTURE IGU USE
10K GALLON LNG RAILSPURS
IGU VACUUM INSULATED 75K GAL LNG STORAGE TANKS WITH TRUCK LOADING RACK
P/L OFFSET FOR 10K BTU/HR/SF THERMAL EXCLUSION ZONE
1.0 & 2.0 MMG LNG FULL CONTAINMENT
1 MMG LNG STORAGE WITH SINGLE CONTAINMENT 10K BTU/HR/SF THERMAL EXCLUSION ZONE MIN 439' TO PROPERTY LINE
1.0 & 2.0 MMG LNG STORAGE WITH FULL CONTAINMENT 10K BTU/HR/SF THERMAL EXCLUSION ZONE MIN 126' & 148' TO PROPERTY LINE
GAS TO PEAKER PLANT OR TURBINES
CONNECTION AT NP FUEL TRANSFER FACILITY
FUEL FORWARDING BLDG (DIESEL)
FUEL FORWARDING BLDG (NAPHTHA)
ALTERNATE OVHD FUEL PIPE ROUTE
100' BUILDING OFFSET
IGU LNG RAIL OFFLOADING FACILITY
IGU BALANCE OF PLANT
125' LNG RAILCAR BUFFER
FUTURE PLANT EXPANSION
1 MMG LNG SINGLE CONTAINMENT
100' BUILDING OFFSET
GVEA PEAKER PLANT
ENTRY
CONTROL BLDG
APPROXIMATE PROPERTY LINE
PUMP BLDG
FUTURE GVEA FUEL STORAGE
2(1.5 MG) FUEL STORAGE
TRUCK OFFLOADING FACILITY
SUBSTATION
PEAKER PLANT ACCESS
TRACKMOBILE & EMERGENCY ACCESS
PRIMARY FUEL PIPE ROUTE
EXIT
NATURAL GAS FROM IGU REGASIFICATION FACILITY
RAILROAD CROSSING
COMM TO CONTROL BUILDING
NEW ACCESS ROAD TO NORTH POLE GENERATION CAMPUS
TRACKMOBILE BUILDING (FUTURE)
GVEA RAIL FACILITY
IGU EASEMENT
138KV OVERHEAD ELECTRIC
FUTURE 20 RAILCAR PETRO STAR RAIL FACILITY
FEED FROM PETRO STAR
FUTURE RAIL SPUR
CITY OF NORTH POLE WATER SUPPLY WELL EDGE OF 2-YEAR TRAVEL ZONE OF INFLUENCE (MAXIMUM)
CITY OF NORTH POLE WATER SUPPLY WELL EDGE OF 2-YEAR TRAVEL ZONE OF INFLUENCE (MINIMUM)

CONSULTANT :

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PROJECT :
GOLDEN VALLEY ELECTRIC ASSOCIATION
3M GALLON STORAGE TANK FOR NORTH POLE GENERATION CAMPUS
NORTH POLE, ALASKA

SHEET TITLE :
SITE LAYOUT ALTERNATIVE 3
CONCEPT DEVELOPMENT

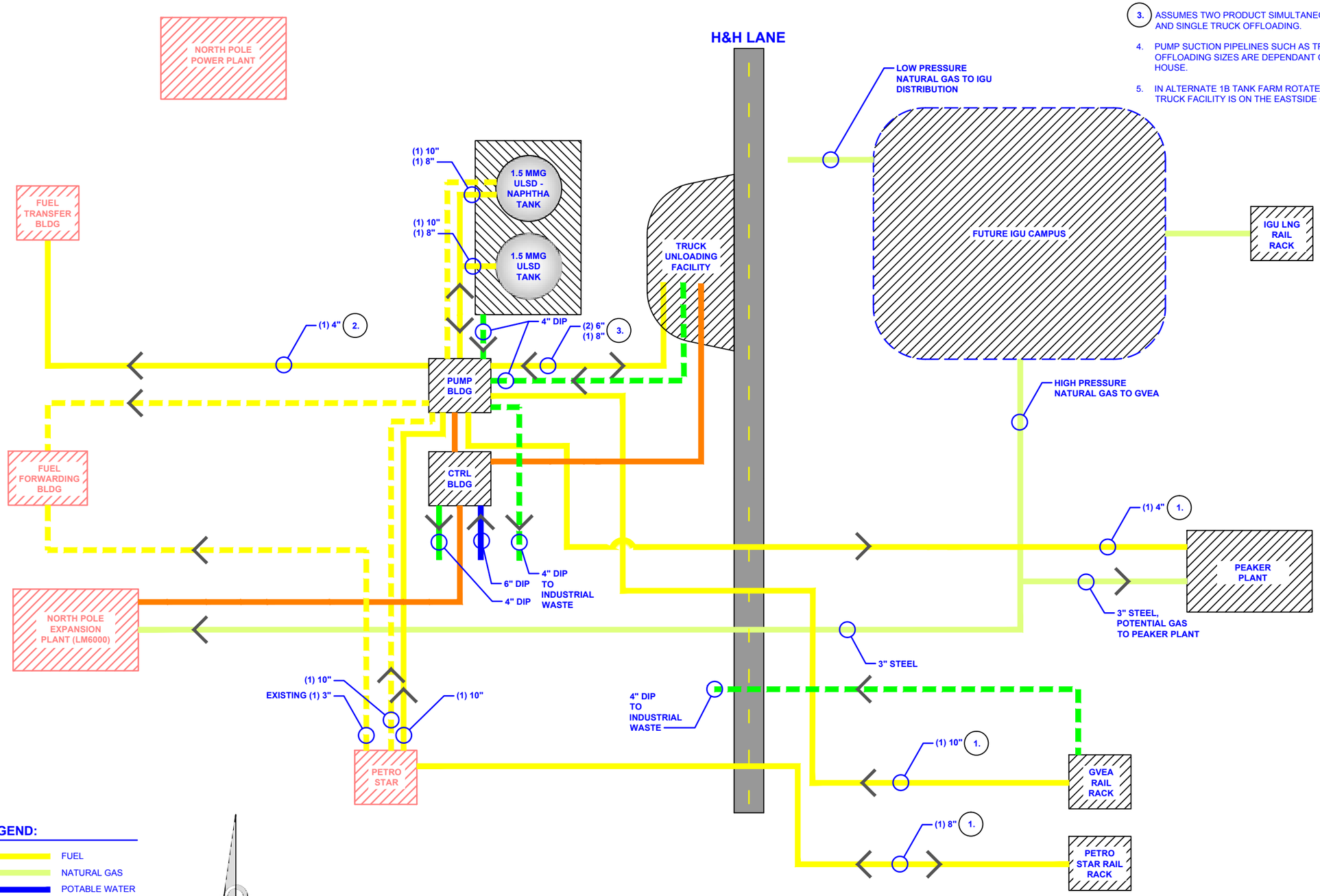
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DATE	JUNE 28, 2017
PROJECT No.	17099FB
SHEET NUMBER	C3.0
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NOTES:

1. ASSUMES SINGLE PIPELINE CAN BE USED FOR ALL PRODUCTS.
2. SIZE ASSUMED BASED ON MAX FLOW RATE OF APPROXIMATELY 400 GPM.
3. ASSUMES TWO PRODUCT SIMULTANEOUS TRUCK LOADING, AND SINGLE TRUCK OFFLOADING.
4. PUMP SUCTION PIPELINES SUCH AS TRUCK AND RAIL OFFLOADING SIZES ARE DEPENDANT ON DISTANCE TO PUMP HOUSE.
5. IN ALTERNATE 1B TANK FARM ROTATED 90 DEGREES AND TRUCK FACILITY IS ON THE EASTSIDE OF H&H.



LEGEND:

- FUEL
- NATURAL GAS
- POTABLE WATER
- SEWER / STORM
- COMM
- OILY WATER
- NAPHTHA

CONSULTANT :

PDC Engineers
1028 Aurora Drive, Fairbanks, Alaska 99709
907.452.1414 | AECC605

PROJECT : GOLDEN VALLEY ELECTRIC ASSOCIATION
3M GALLON STORAGE TANK FOR NORTH POLE GENERATION CAMPUS
NORTH POLE, ALASKA

SHEET TITLE : SCHEMATIC - FUEL PIPING ALTERNATIVE 1A
CONCEPT DEVELOPMENT

DESIGN	DES
DRAWN	RJP
CHECKED	KAB
DATE	JUNE 28, 2017

PROJECT No. 17099FB

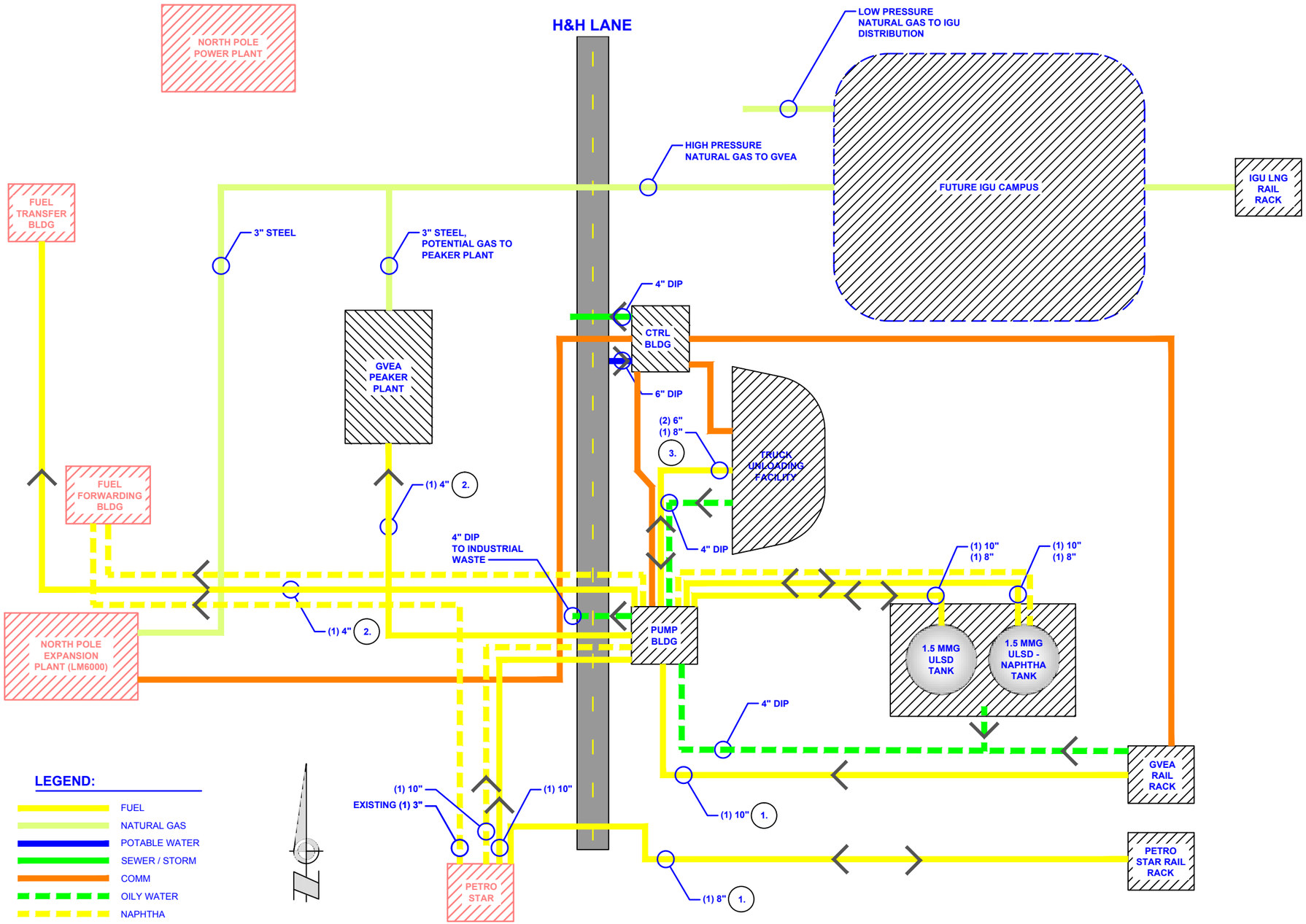
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NOTES:

1. ASSUMES SINGLE PIPELINE CAN BE USED FOR ALL PRODUCTS.
2. SIZE ASSUMED BASED ON MAX FLOW RATE OF APPROXIMATELY 400 GPM.
3. ASSUMES TWO PRODUCT SIMULTANEOUS TRUCK LOADING, AND SINGLE TRUCK OFFLOADING.
4. PUMP SUCTION PIPELINES SUCH AS TRUCK AND RAIL OFFLOADING SIZES ARE DEPENDANT ON DISTANCE TO PUMP HOUSE.



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CONSULTANT :

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1028 Aurora Drive, Fairbanks, Alaska 99709
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PROJECT :
GOLDEN VALLEY ELECTRIC ASSOCIATION
3M GALLON STORAGE TANK FOR NORTH POLE GENERATION CAMPUS
NORTH POLE, ALASKA

SHEET TITLE :
SCHEMATIC - FUEL PIPING ALTERNATIVE 2
CONCEPT DEVELOPMENT

DESIGN	DES
DRAWN	RJP
CHECKED	KAB
DATE	JUNE 28, 2017

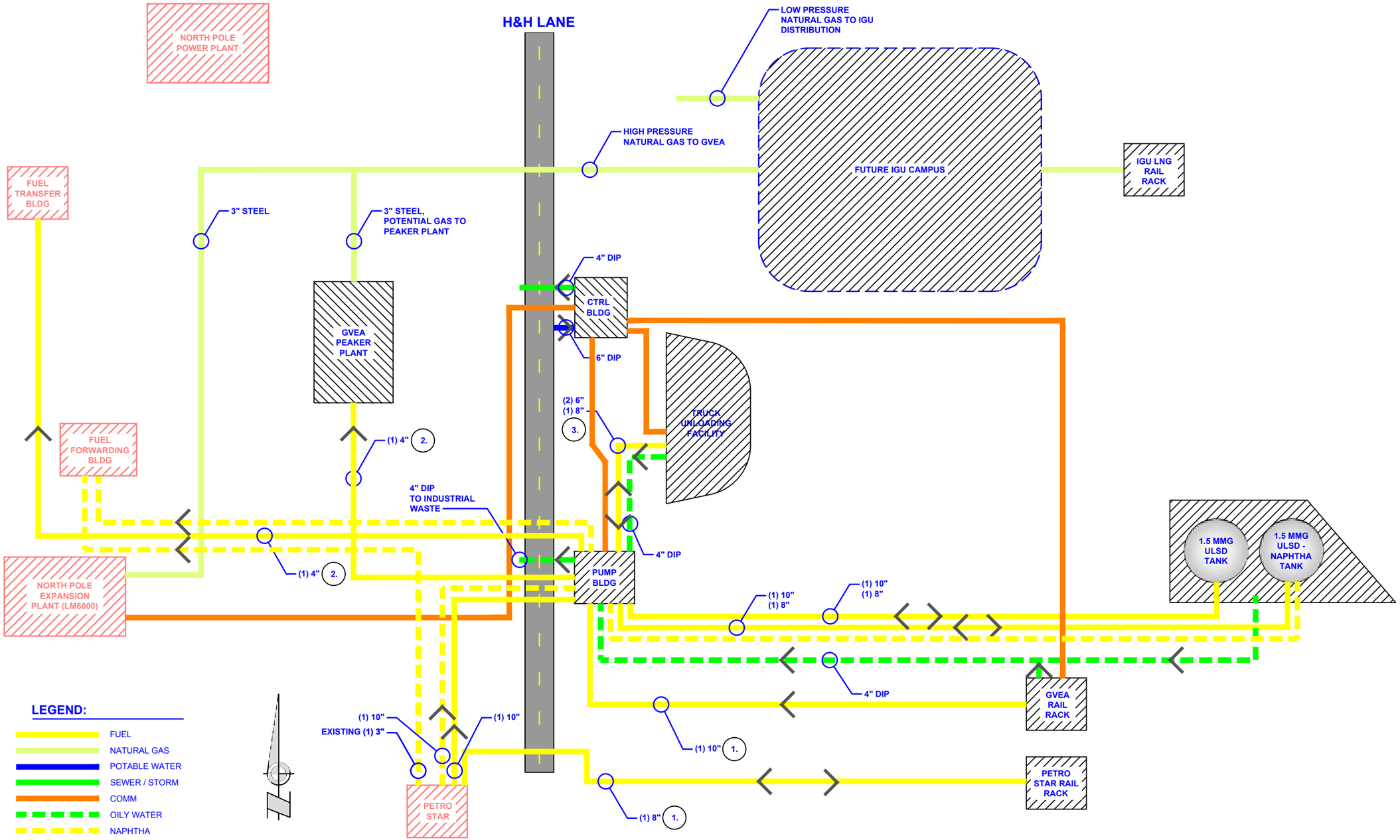
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17099FB

SHEET NUMBER
C2.3
OF - SHEETS

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NOTES:

1. ASSUMES SINGLE PIPELINE CAN BE USED FOR ALL PRODUCTS.
2. SIZE ASSUMED BASED ON MAX FLOW RATE OF APPROXIMATELY 400 GPM.
3. ASSUMES TWO PRODUCT SIMULTANEOUS TRUCK LOADING, AND SINGLE TRUCK OFFLOADING.
4. PUMP SUCTION PIPELINES SUCH AS TRUCK AND RAIL OFFLOADING SIZES ARE DEPENDANT ON DISTANCE TO PUMP HOUSE.



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CONSULTANT :

PDC Engineers
1028 Aurora Drive, Fairbanks, Alaska 99709
907.452.1414 | AECC605

PROJECT :
GOLDEN VALLEY ELECTRIC ASSOCIATION
3M GALLON STORAGE TANK FOR NORTH POLE GENERATION CAMPUS
NORTH POLE, ALASKA

SHEET TITLE :
SCHEMATIC - FUEL PIPING ALTERNATIVE 3
CONCEPT DEVELOPMENT

DESIGN	DES
DRAWN	RJP
CHECKED	KAB
DATE	JUNE 28, 2017

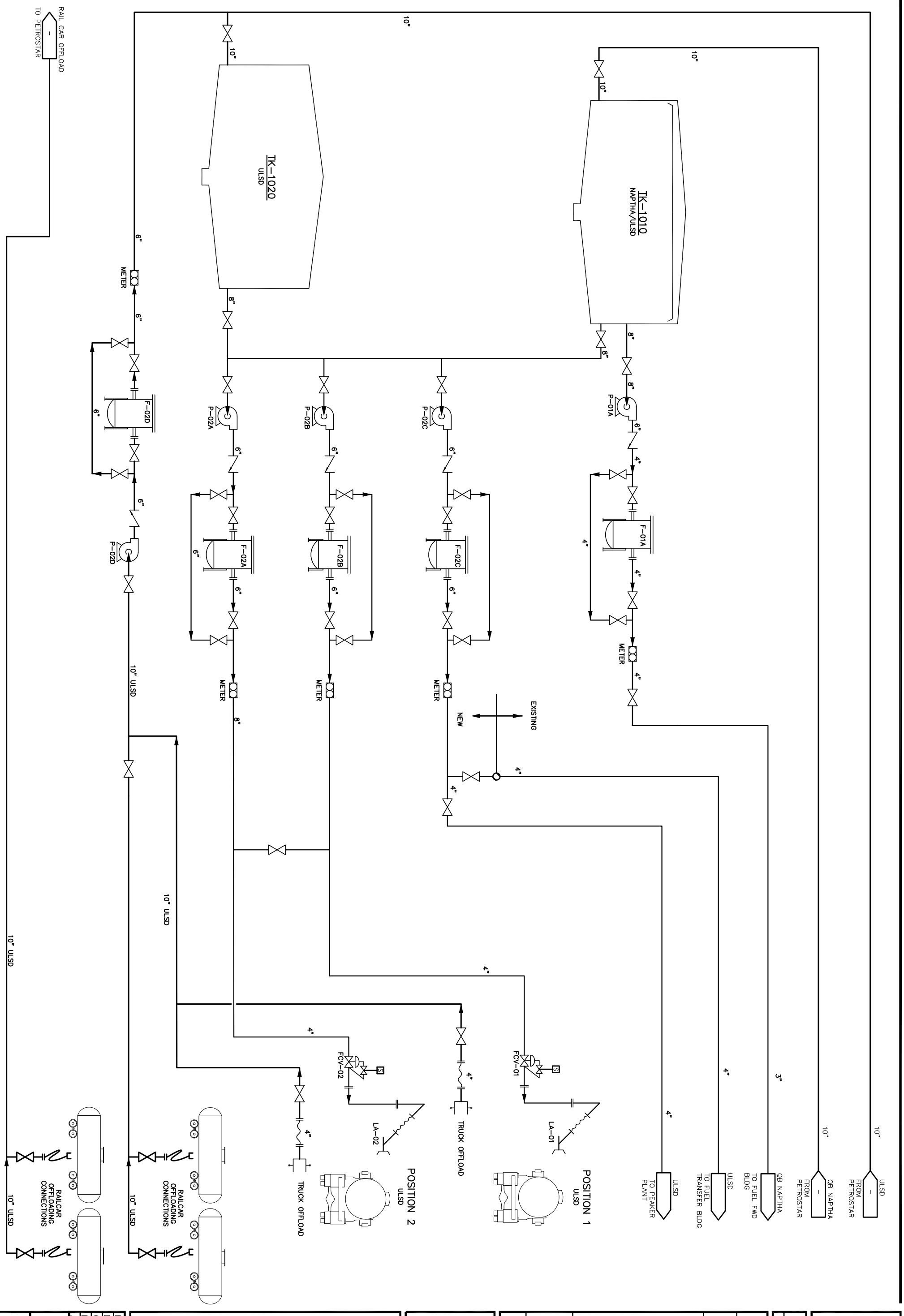
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Attachment 2



FLOW DIAGRAM
SYSTEM OVERVIEW
3MM GALLON TANK FARM
GOLDEN VALLEY ELECTRIC ASSOC.
NORTH POLE, ALASKA

GREAT NORTHERN ENGINEERING
1300 E. ARCTIC, SUITE 101
PALMER, AK 99645
(907) 745-6988

REV	DATE	REVISION DESCRIPTION	DWN	CHK
B	06/27/17	ISSUED FOR REVIEW	DK	DK

DATE SIGNED

DATE:	05/26/17
DRAWN:	JM
CHECKED:	DK
DESIGNED:	DK
APPROVED:	DK

PD-01 DWG NO. B REV.

17013 PROJECT NO.

LINE LIST

Line No.	Service	Description	From	To	Size (in)	Schedule	ANSI Class	Design Flow Rate (gpm)	Velocity (ft/s)	Dual Flow Direction (Y/N)
FA-010	ULSD	Truck Offload	Truck Load Rack	Pump Bldg	10	Std	150	1200	4.89	N
FA-020	ULSD	Truck Loading	Pump Bldg	Truck Load Rack	6	Std	150	600	6.79	N
FA-030	ULSD	Truck Loading	Pump Bldg	Truck Load Rack	6	Std	150	600	6.79	N
FA-040	ULSD	GVEA RR Offload	GVEA Rail Rack	Pump Bldg	10	Std	150	1200	4.89	N
FA-050	ULSD	Cargo from Petro Star	Petro Star Facility	Pump Bldg	10	Std	150	2000	8.15	N
FA-060	Naptha	Cargo from Petro Star	Petro Star Facility	Pump Bldg	10	Std	150	2000	8.15	N
FA-070	ULSD	Cargo to Tank 1	Pump Bldg	Tank 1	10	Std	150	1200	4.89	N
FA-080	ULSD	Service from Tank 1	Tank 1	Pump Bldg	8	Std	150	1200	7.64	N
FA-090	ULSD	Cargo to Tank 2	Pump Bldg	Tank 2	10	Std	150	1200	4.89	N
FA-100	ULSD	Service from Tank 2	Tank 2	Pump Bldg	8	Std	150	1200	7.64	N
FA-110	Naptha	Cargo to Tank 2	Pump Bldg	Tank 2	10	Std	150	1200	4.89	N
FA-120	Naptha	Service from Tank 2	Tank 2	Pump Bldg	8	Std	150	1200	7.64	N
FA-130	ULSD	Service to Fuel Transfer Bldg	Pump Bldg	Fuel Transfer Bldg	4	Std	150	400	10.19	N
FA-140	ULSD	Service to Peaker Plant	Pump Bldg	Peaker Plant	4	Std	150	400	10.19	N
FA-150	Naptha	Service to Fuel Fwd Bldg	Pump Bldg	Fuel Fowarding Bldg	3	Std	150	250	11.32	N
FA-160	ULSD	*Petro Star RR Load/Offload	Petro Star Rail Rack	Petro Star Facility	10	Std	150	1200	4.89	Y
FA-170	Naptha	**Service to Fuel Fwd Bldg	Petro Star Facility	Fuel Fowarding Bldg	3	Std	150	250	11.32	N

* This pipeline is NIC
** This pipeline is exsting and may be tied into outside of Fuel Forwarding Bldg

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

June 2017

Submitted To:
PDC Engineers, Inc.
1028 Aurora Drive
Fairbanks, Alaska 99709

By:

Shannon & Wilson, Inc.
2355 Hill Road
Fairbanks, Alaska 99709
AECC125

Phone: (907) 479-0600
Fax: (907) 479-5691

31-1-20006-001R1

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FIGURE

1 Site Plan and Approximate Boring Locations

APPENDICES

A Soil Classification and Boring Logs
B Geotechnical Laboratory Data
C Project Photographs
D *Important Information About Your Geotechnical/Environmental Report*

GEOTECHNICAL FINDINGS REPORT
GVEA FUEL STORAGE FACILITY
NORTH POLE, ALASKA

1.0 INTRODUCTION

This report presents the results of our concept phase geotechnical services for the proposed fuel storage facility project in North Pole, Alaska. The purpose of our services was to explore subsurface conditions and provide a report of our geotechnical findings to assist in evaluation of conceptual site development plans.

Our services were performed consistent with our proposal dated February 17, 2017. Per your June 26, 2017 request, we have revised our report submitted on June 2, 2017 to include additional ground improvement discussion. This report was prepared for the exclusive use of PDC Engineers, Inc. and their representatives for the fuel storage tank project.

1.1 Project Understanding

We understand GVEA plans to construct a fuel-storage facility to support their power-generation plant in North Pole. GVEA requested a concept phase preliminary assessment of available land and development of three siting options. Future detailed design phases will be conducted to provide detailed exploration of the selected site and concept, and to prepare a final design of the fuel facility. This report presents the results of our concept phase preliminary explorations and a discussion of potential geotechnical site development and design concerns.

We understand two parcels are being considered for the fuel-storage facility site: the 33.8-acre Lot 2 of H&H Industrial Subdivision, and the southeast portion of Lot F1A of the ASLS 2003-50 Subdivision. Based on our previous discussions with GVEA, we also understand the southwest corner of Lot 2 has been considered a primary area of focus for this fuel storage development. We also understand these sites may include a future gasification plant and an additional power plant, as part of an energy campus.

The proposed fuel storage development is planned to include 3 million gallons of fuel storage, a surrounding catch basin, unloading area, and connection to the existing GVEA facility. The intent of this phase of services is to evaluate concepts plans and for site development, as well as to develop a preliminary geotechnical evaluation of likely geotechnical requirements for site development.

Our services are based on:

- The limitations of our approved scope, schedule, and budget.
- Our understanding of the project and information provided by Enterprise Engineering, Inc.
- The results of testing performed on samples we collected from the explorations.

The explorations were performed to evaluate geotechnical conditions at the project area. Our observations are specific to the locations, depths, and dates noted on the boring logs, and may not be applicable to all areas of the site. No amount of explorations or testing can precisely predict the characteristics, quality, or distribution of subsurface and site conditions. Potential variation includes, but is not limited to:

- The conditions between and below explorations may be different.
- The passage of time or intervening causes (natural and manmade) may result in changes to site and subsurface conditions.
- Groundwater levels and flow directions may fluctuate due to seasonal variations.
- Penetration test results in frozen or gravelly soils may be unrealistic. Actual soil density may be lower than estimated if the test was performed on a gravel or cobble.
- Contaminant concentrations may change in response to natural conditions, chemical reactions, and/or other event.
- The presence, distribution, and concentration of contaminants may vary from our sampling locations. Our tests may not represent the highest contaminant concentrations at the site.

If conditions different from those described herein are encountered during construction, we should review our description of the subsurface conditions and reconsider our recommendations and conclusions.

1.2 Scope of Services

Our scope of services included site subsurface explorations, geotechnical laboratory testing of select soil samples, preliminary liquefaction analyses, and preparation of this findings report.

The authorized scope of services was based on your objectives, schedule, and budget. Our scope of services did not include an environmental site assessment or wetland delineation for the project site, or for any of the contaminated sites near the proposed facility. It also did not include research or evaluating the presence of cultural resources at or around the site. If a service is not specifically indicated in this report, do not assume that it was performed.

2.0 FIELD EXPLORATION AND LABORATORY ANALYSES

Our field work consisted of drilling and sampling 5 exploratory borings, designated 17-01 through 17-05, within the proposed project area. Boring 17-01 through 17-04 were located on Lot 2 of H&H Subdivision and boring 17-05 was located on Lot F1A of the ASLS 2003-50 Subdivision. Field explorations were conducted between May 15, 2017 and May 18, 2017. We subcontracted Homestead Drilling of Fairbanks (Homestead) to perform the exploratory drilling.

Peter Grey, a geotechnical staff member with our firm, observed drilling operations, logged subsurface conditions, and collected geotechnical soil samples for soil classification and laboratory testing. The approximate location of the borings are shown in Figure 1; boring logs are presented in Appendix A.

2.1 Field Exploration and Drilling Methods

Homestead advanced the borings using a Mobile B61 track-mounted and Mobile B61 truck-mounted drill rig both of which were equipped with continuous-flight hollow-stem augers. Homestead advanced and sampled the borings to 61.5 feet below the ground surface (bgs). As the borings progressed, we generally collected a grab sample from the surface to 2 feet bgs, and split-spoon samples at 2.5-foot intervals to 20 feet bgs, 5 foot intervals to 50 feet, and 10 foot intervals thereafter, using a 2½-inch inside-diameter split-spoon sampler.

The split-spoon samples were obtained by driving the sampler into the soils at the base of the auger using a 340-pound automatic hammer falling 30 inches onto the drill rods. The number of blows required to advance the sampler 6 inches is recorded over three intervals, resulting in 18 inches of penetration. For each sample, the number of blows required to advance the sampler the final 12 inches is termed the penetration resistance, a measure of the relative consistency of unfrozen fine-grained soils and relative density of unfrozen granular soils. We classified soil samples recovered using these techniques in the field, sealed them in airtight containers, and returned them to our laboratory for testing.

We performed field screening of split-spoon samples above the groundwater table using a hand-held photoionization detector (PID). Soil observations and PID readings are included in the boring logs presented in Appendix A.

The explorations were performed to evaluate subsurface conditions at the site for the proposed fuel facility and associated structures. Our observations are specific to the locations, depths, and dates noted on the logs, and may not be applicable to all areas of the site.

2.2 Geotechnical Laboratory Testing

We visually reviewed field soil classifications in our laboratory and selected samples for testing. We performed moisture-content analyses on frozen samples and samples collected above the water table, and grain-size distribution analyses on select samples. Moisture-content results are plotted on the boring logs in Appendix A. Grain-size distribution curves are shown in Appendix B. Photographs of samples we collected are presented in Appendix C.

3.0 SITE CONDITIONS

3.1 Geological Setting

North Pole is within the Tanana Lowlands physiographic province, which forms a large arcuate band of alluvial sediments between the Alaska Range and the Yukon-Tanana Uplands. The Lowlands consist of vegetated floodplains and low benches cut by the Tanana River, and sloughs and oxbow lakes representing former channel positions of the Tanana or Chena Rivers. Soils in the Lowlands consist of interbedded alluvial sand and gravel covered by silty overbank deposits. The thickness of the alluvial sediments overlying bedrock in the project area is unknown.

Although the depth of alluvial sediments has not been well established in North Pole, it has been established to be as great as 400 feet to 500 feet in the Fairbanks area. We anticipate the thickness of alluvial deposits in North Pole would be similar to Fairbanks. Former slough channels are commonly filled with organic silt and peat deposits. These deposits are laterally discontinuous and vary in thickness. The portion of the Tanana Lowlands in which the site is located has not been glaciated.

The North Pole area is in a subarctic zone underlain by discontinuous permafrost. Permafrost is defined as ground that has remained at a temperature of 32 degrees Fahrenheit or less for two or more years. Although the depth of permafrost has not been well established in North Pole, the maximum depth of permafrost measured in the Fairbanks area is in excess of 250 feet. We anticipate the depth of permafrost in North Pole would be similar to Fairbanks. The thickness of the “active layer,” the portion of the ground at or near the surface that undergoes an annual freeze-thaw cycle, is largely dependent on the type of ground cover and snow depth. Seasonal frost-penetration commonly exceeds 10 feet beneath roads or parking areas kept free of snow during winter. In areas covered by thick mats of tundra or organic material, the thickness of the active zone is often 2 feet or less.

3.2 Seismicity

The North Pole area lies between two right-lateral shear systems: the Denali Fault System approximately 60 miles to 80 miles south of Fairbanks, and the Kaltag and Tintina Fault Systems, approximately 80 miles north. The shear along these systems is believed to be the result of crustal adjustments in the North American Plate due to convergence with the Pacific Plate along the Gulf of Alaska.

Within the past century, the area has been subjected to four large earthquakes. On July 22, 1937, a magnitude 7.3 (M_S) event occurred about 23 miles southeast of Fort Wainwright. This event, widely felt throughout central Alaska, produced extensive ground failures in the epicentral area (Page, and others, 1995). Two other earthquakes were an October 15, 1947, M_s 7.2 event about 41 miles south-southwest of Fairbanks, and an August 27, 1904, M_s 7.3 event about 17 miles southwest. A November 3, 2002, M_s 7.9 event on the Denali Fault, approximately 90 miles south of Fairbanks, was felt widely throughout central and southern Alaska, and resulted in minor liquefaction in the Fairbanks area. The peak horizontal ground acceleration of this event recorded on bedrock at the UAF campus was 0.09g.

3.3 Surface Conditions

The Lot 2 parcel is located east of H&H Road and historic photos and studies indicate previous development activity from farmland in the 1970s to initial site development for a refinery in the early 1980s. We evaluated aerial images, and past studies, and portions of the parcel have been cleared and fill materials were placed, but structures were not constructed and vegetation including birch, aspen, and spruce trees and scrub brush has regrown. We also note an abandoned slough that runs approximately from north to south in the middle of the lot.

The Lot F1A parcel is located west of H&H Road and is has been developed by previous owners. The site is generally flat, and includes structures, paving, and landscaped areas.

3.4 Subsurface Conditions

We observed similar conditions in some of our borings. We observed approximately 6 feet to 9.5 feet of silty, frost susceptible soils overlying alluvial sands and gravels to the depths explored. In Boring 17-02, we observed gravel with silt from approximately 2 feet bgs to 4.5 feet bgs that we believe is imported fill material.

We observed groundwater at depths ranging of approximately 3.5 feet bgs to 12 feet bgs at the time of drilling. We did not observe permafrost during exploration; a layer of remnant seasonal frost was observed from approximately 2 feet bgs to 4.5 feet bgs at the time of drilling.

4.0 EARTHQUAKE HAZARDS ANALYSIS

The project is in a seismic area where major earthquakes can and have occurred. Earthquake-induced geologic hazards that may affect a site include ground-surface fault rupture, and liquefaction and associated effects (e.g., loss of shear strength, bearing-capacity failures, loss of lateral support, ground oscillation, and lateral spreading). An associated effect of earthquake shaking is densification of the soils and potential ground settlement. Due to the presence of relatively loose soils and a shallow water table, the primary seismic hazard at the site is liquefaction. In borings drilled for the project, several samples from below the water table had uncorrected penetration resistance values (blow counts) of less than 20; some had blow counts of less than 10.

It has been our experience that soils in the Fairbanks area with blow counts as low as these are susceptible to liquefaction and dynamically induced densification if subjected to earthquake ground motions implied by the 2015 IBC. Densification of granular soils above and below the water table during earthquake shaking could result in significant ground settlement at the site. Associated effects of liquefaction may include a loss of soil shear strength, potential bearing-capacity failures, and lateral spreading. Our preliminary analysis of earthquake ground motions and earthquake-induced geologic hazards that may affect the site are described below.

4.1 Earthquake Ground Motion

Structural design performed in seismic regions for essential facilities generally requires a site-specific seismic analysis. For this concept phase study, we based our analyses on published seismic parameters. A site specific seismic analysis is being conducted for this project based on 150-foot-deep shear wave velocity testing conducted for the GVEA power plant, and will be presented as part of our final studies.

We developed seismic ground motions for the liquefaction analyses in general accordance with the 2015 NEHRP Provisions. The 5 percent damped design spectral response acceleration is defined as two-thirds of the site-adjusted maximum considered earthquake (MCE). The MCE was determined using maps for Site Class B published by the U.S. Geological Survey for ground motions with a two percent chance of occurrence in 50 years. We adjusted these values assuming Site Class D conditions at the site; sample penetration resistance values from our

explorations suggest that Site Class D soil conditions prevail at the site without regard for liquefaction. The mapped MCE geometric mean peak ground acceleration (PGA_M) was derived using 2010 ASCE 7 (with 2013 errata).

The following table summarizes earthquake ground motion parameters for this site.

Description	Parameter	Value
Site Class		D
Mapped spectral accelerations for 0.2 seconds (Site Class B, 5% damping)	S_s	0.99g
Mapped spectral accelerations for 1 second (Site Class B, 5% damping)	S_1	0.38g
S_s adjusted for site class	S_{MS}	1.09g
S_1 adjusted for site class	S_{M1}	0.73g
Design spectral response acceleration at short periods	S_{DS}	0.73g
Design spectral response acceleration at 1-second period	S_{D1}	0.49g
Peak ground acceleration	PGA_M	0.48g

4.2 Geologic Hazard Analyses

Earthquake-induced geologic hazards that we reviewed include landsliding, fault rupture, and liquefaction and its associated effects (e.g., loss of shear strength, bearing capacity failures, loss of lateral support, ground oscillation, lateral spreading, and settlement). In our opinion, due to the flat topography at the site, the risk of landsliding is low.

Seismicity in the Fairbanks-North Pole area has historically been concentrated in clusters or bands with a northeast-southwest trend that indicates active faulting, although no faults with Holocene displacement have been recognized in the area. An assessment of geologic maps reveals no conclusive evidence of faulting or fault-related geomorphic structures in the area; however, the absence of obvious fault-related geomorphic structures does not preclude the possibility of active faults in the area. In our opinion, the risk for surface-fault rupture at the project site is low.

4.3 Liquefaction Analyses

Liquefaction of loose, saturated, cohesionless soils occurs when excess pore pressures are generated as a result of earthquake shaking. Additionally, densification of the granular soils above and below the water table could occur when subject to earthquake shaking, resulting in

ground settlement at the site. The most widely used methods to evaluate liquefaction potential are empirical and based on correlations between Standard Penetration Test (SPT) resistance (N-value), PGA, and earthquake magnitude. We assumed a magnitude 7.3 for our analyses based on recent earthquakes that have occurred near the area and a peak ground acceleration (PGA_M) of 0.48g in the analyses.

We used three empirical procedures to evaluate liquefaction potential at this site:

- Youd and others (2001)
- Cetin and others (2004)
- Idriss and Boulanger (2014)

In these procedures, the N-value (blow count) is correlated to the liquefaction resistance of the soil (expressed as cyclic resistance ratio). The soil resistance is compared to the earthquake-induced loading (expressed as cyclic stress ratio), and a corresponding factor of safety (FS) against liquefaction is calculated.

In accordance with Section C11.8.3 in ASCE 07, we considered the soil to be potentially liquefiable if the calculated factor of safety is less than or equal to 1. The primary effect of liquefaction at the site is a reduction in the soil shear strength, settlement, and a reduction in bearing capacity.

We used the relationships by Tokimatsu and Seed (1987) and Ishihara and Yoshimine (1992), relating earthquake ground motion and penetration resistance with volumetric strain, to estimate the potential for free-field ground settlement in the borings we considered in the liquefaction analyses.

Using these relationships, in conjunction with the three procedures used to evaluate liquefaction potential in the borings we advanced at the site, we estimate 6 to 8 inches or more of free-field settlement could occur at the ground surface. In our opinion, the ground settlement may not occur uniformly over the project area and could be differential across the site.

4.4 Lateral Spreading

Liquefaction in gently sloping ground or ground adjacent to a free face can result in permanent lateral ground displacement in a phenomenon known as lateral spreading. Lateral spreading ground movement can occur toward a free face during or after seismic shaking in saturated, loose to medium dense, granular soil. Because the proposed structure is more than several hundred

feet from the nearest body of water, we believe the risk of lateral spreading for the project site is low.

5.0 DISCUSSION

We observed silty frost susceptible soils overlying alluvial sands and gravels to the depths explored. These silty soils are potentially compressible and frost-susceptible, and may contain organic slough deposits. Site development for structures will require replacing these soils down to relatively clean sands and gravels to improve bearing conditions and reduce the potential for consolidation- related settlement.

Our analyses show potential for widespread liquefaction in the soil mass below the groundwater table during the design earthquake. As a result, 6 inches to 8 inches or more of total and differential ground settlement along with reduction in soil strength could occur. We understand the project is an essential facility and ground improvement will be required to mitigate the liquefaction hazards. Soil improvement has two objectives: 1) to reduce potential dynamic settlement; and 2) improve soil shear strength during a seismic event and reduce the potential for a bearing-capacity failure during liquefaction.

5.1 Ground Improvement

Our approach to ground improvement is to densify the soil sufficiently both above and below the water table to reduce settlement and increase residual soil strength during a design seismic event. The increased residual soil strength will reduce the potential for a punching-type bearing-capacity failure and liquefaction-induced settlement.

In our opinion, deep dynamic compaction (DDC) and vibro-compaction ground improvement are both appropriate techniques that could be used to densify and improve soil conditions at this site.

DDC produces low frequency vibrations that could exceed peak particle velocities of 0.75 inches per second at distances of 75 feet or more from the improvement area. Vibrocompaction produces higher frequency vibrations which may produce peak particle velocities of 0.75 inches per second, or more, up to 30 feet from the point of ground improvement. Vibrocompaction ground improvement can be 3 to 5 times more expensive than DDC. If existing structures and improvements are 100 feet to 150 feet or more from the proposed site(s), DDC may be an appropriate method of ground improvement.

The soil improvement we recommend considering has two components:1) excavating the surficial silty soils and replacing with a relatively thick section of compacted sand and gravel

(i.e., structural fill) beneath foundation systems; and 2) densifying the soils below the water table using DDC techniques.

DDC, as referred to in this report, is a ground-improvement technique whereby a large tamper/weight (usually 6 tons to 40 tons) is dropped from a specified height (usually 30 feet to 120 feet) to compact materials in-place. We believe ground improvement may be performed using DDC techniques, based on our successful experience with DDC on multiple projects in similar soil conditions.

DDC soil improvement has been used for several projects in Fairbanks, including the FTW373A Warm Storage Hangar on Fort Wainwright, Hangar 6 on Fort Wainwright, the Carlson Center, the Bureau of Land Management (BLM) building on University Avenue, the FTW357 GSAB Hangar, and the FTW348A AAC Hangar. Soil improvement using vibro-compaction was completed for the University of Fairbanks Combined Heat and Power Plant, the Fairbanks Memorial Hospital Surgery Addition, Bassett Hospital on Fort Wainwright and the Alaska Department of Fish and Game Sport Fish Hatchery in Fairbanks.

5.2 Ground Vibration Monitoring

Visual pre-and post-condition surveys and vibration monitoring during ground improvement is recommended. At a minimum, vibration monitoring and pre-and-post condition surveys are recommended for building structures and utilities within a 150-foot radius of the proposed ground improvement areas, if anticipated ground vibrations exceed 2 inches per second when the frequency is 40 Hz or greater, or 0.75 inches per second when the frequency is less than 40 Hz at structures of concern.

Our experience suggests the frequency of DDC-induced ground motions, generated by a 15-ton weight dropped 50 feet, ranged from 5 to 18 Hz, and were typically less than 10 Hz. Recorded vibrations were about 0.75 inches per second 55 feet from the source, 0.5 inches per second 75 feet from the source, and 0.2 inches per second 150 feet from the source. We anticipate similar vibration levels and frequency for DDC-induced ground motions for this project; however, vibrations are dependent on several factors including depth to groundwater, density of soils, and soil type. We recommend intermittently monitoring ground vibrations within 150 feet of the improvement area to assess frequency and vibration levels and verify thresholds are not exceeded outside the 150-foot radius.

6.0 GEOTECHNICAL CONSIDERATIONS FOR SITE DEVELOPMENT

The following key geotechnical site development and design considerations have been identified during this concept phase study.

- The proposed sites have a significant seismic liquefaction hazard; primarily loss of shear strength and settlement during design seismic events.

- Site preparation for all structures will require removal of surficial silty frost susceptible soils and replacement with compacted structural fills.

- Ground improvement will be required for all essential facilities. Ground improvement will include the entire structure footprint and extend out beyond the outside edge of all foundations a minimum of 25 feet. The depth of required improvement, based on the initial subsurface findings, is about 30 to 35 feet below grade.

- Considerations should be given to performing ground improvement for future planned structure sites as well as initial site development. Future developments near initial planned developments could require more costly ground improvement techniques.

- Site preparation and DDC ground improvement should be performed during periods of low groundwater to maximize the depth of ground improvement. Low groundwater typically occurs in the spring.

7.0 CLOSING

This geotechnical findings report was prepared for the exclusive use of PDC Engineers, Inc. and their representatives for the design of the GVEA Fuel Storage Facility in North Pole, Alaska. This report should not be used without our approval if any of the following occurs:

- Conditions change due to natural forces or human activity under, at, or adjacent to the site.
- Assumptions stated in this report have changed.
- Project details change or new information becomes available such that our conclusions and recommendations may be affected.
- If the site ownership or land use has changed.
- More than one year has passed since the date of this report.

If any of these occur, we should be retained to review the applicability of our recommendations.

Shannon & Wilson, Inc., has prepared the document *"Important Information About Your Geotechnical/Environmental Report"* in Appendix D to assist you and others in understanding the uses and limitations of our reports. Please read this document to learn how you can lower your risks for this project.

Geotechnical Findings:
SHANNON & WILSON, INC.

Stephen Adamczak, Jr. P.E.
Vice President



Image provided courtesy of Pictometry International 2012

0 200 400 600

Feet

LEGEND

- Approximate Boring Location
- Alternative 1 Tank Location
- Alternative 3 Tank Location
- Alternative 2 Tank Location

Geotechnical Findings Report
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SITE PLAN AND APPROXIMATE BORING LOCATIONS

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC. GEOTECHNICAL AND ENVIRONMENTAL CONSULTANTS

Figure 1

APPENDIX A

SOIL BORING LOGS AND SOIL CLASSIFICATION

APPENDIX A

SOIL BORING LOGS AND SOIL CLASSIFICATION

TABLES

A-1 Summary of Frozen Soil Classification System

FIGURES

A-1 Soil Description and Log Key
A-2 Log of Boring 17-01
A-3 Log of Boring 17-02
A-4 Log of Boring 17-03
A-5 Log of Boring 17-04
A-6 Log of Boring 17-05

TABLE A-1
SUMMARY OF FROZEN SOIL CLASSIFICATION SYSTEM

Description			Designation
Segregated ice is not visible by eye	Friable, poorly bonded Material is easily broken up		Nf
	Well bonded – Soil particles strongly held together by ice	No excess ice	Nbn
		Excess ice	Nbe
Segregated ice is visible by eye (less than 1 inch thick)	Individual ice crystals or inclusions		Vx
	Ice coatings on soil particles		Vc
	Stratified or distinctly oriented ice formations		Vs
	Randomly or irregularly oriented ice formations		Vr
Ice greater than 1 inch thick	Ice with soil inclusions		ICE + soil type
	Ice without soil inclusions		ICE

Note:
Based on Linell, K.A. and C.W. Kaplar, 1966, Description and Classification of Frozen Soils, U.S. Army Cold Regions Research Engineering Laboratory, Technical Report 150, Hanover, N.H.

Shannon & Wilson, Inc. (S&W), uses a soil identification system modified from the Unified Soil Classification System (USCS). Elements of the USCS and other definitions are provided on this and the following pages. Soil descriptions are based on visual-manual procedures (ASTM D2488) and laboratory testing procedures (ASTM D2487), if performed.

S&W INORGANIC SOIL CONSTITUENT DEFINITIONS

CONSTITUENT[2]	FINE-GRAINED SOILS (50% or more fines)[1]	COARSE-GRAINED SOILS (less than 50% fines)[1]
Major	***Silt, Lean Clay, Elastic Silt,*** or ***Fat Clay***[3]	***Sand*** or ***Gravel***[4]
Modifying (Secondary) Precedes major constituent	30% or more coarse-grained: ***Sandy*** or ***Gravelly***[4]	More than 12% fine-grained: ***Silty*** or ***Clayey***[3]
Minor Follows major constituent	15% to 30% coarse-grained: ***with Sand*** or ***with Gravel***[4]	5% to 12% fine-grained: ***with Silt*** or ***with Clay***[3]
	30% or more total coarse-grained *and* lesser coarse-grained constituent is 15% or more: ***with Sand*** or ***with Gravel***[5]	15% or more of a second coarse-grained constituent: ***with Sand*** or ***with Gravel***[5]

[1]All percentages are by weight of total specimen passing a 3-inch sieve.
[2]The order of terms is: *Modifying Major with Minor*.
[3]Determined based on behavior.
[4]Determined based on which constituent comprises a larger percentage.
[5]Whichever is the lesser constituent.

MOISTURE CONTENT TERMS

Dry	Absence of moisture, dusty, dry to the touch
Moist	Damp but no visible water
Wet	Visible free water, from below water table

STANDARD PENETRATION TEST (SPT) SPECIFICATIONS

Hammer:	140 pounds with a 30-inch free fall. Rope on 6- to 10-inch-diam. cathead 2-1/4 rope turns, > 100 rpm NOTE: If automatic hammers are used, blow counts shown on boring logs should be adjusted to account for efficiency of hammer.
Sampler:	10 to 30 inches long Shoe I.D. = 1.375 inches Barrel I.D. = 1.5 inches Barrel O.D. = 2 inches
N-Value:	Sum blow counts for second and third 6-inch increments. Refusal: 50 blows for 6 inches or less; 10 blows for 0 inches.

NOTE: Penetration resistances (N-values) shown on boring logs are as recorded in the field and have not been corrected for hammer efficiency, overburden, or other factors.

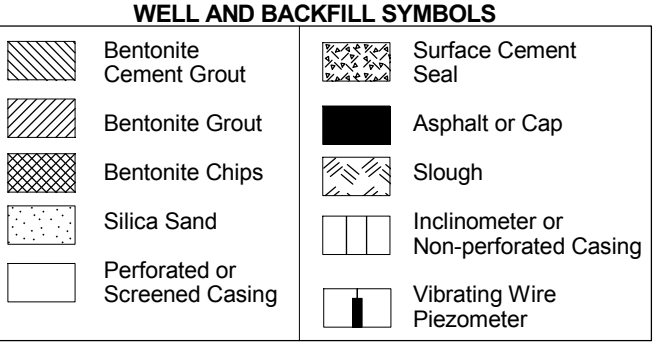
PARTICLE SIZE DEFINITIONS

DESCRIPTION	SIEVE NUMBER AND/OR APPROXIMATE SIZE
FINES	< #200 (0.075 mm = 0.003 in.)
SAND	
Fine	#200 to #40 (0.075 to 0.4 mm; 0.003 to 0.02 in.)
Medium	#40 to #10 (0.4 to 2 mm; 0.02 to 0.08 in.)
Coarse	#10 to #4 (2 to 4.75 mm; 0.08 to 0.187 in.)
GRAVEL	
Fine	#4 to 3/4 in. (4.75 to 19 mm; 0.187 to 0.75 in.)
Coarse	3/4 to 3 in. (19 to 76 mm)
COBBLES	3 to 12 in. (76 to 305 mm)
BOULDERS	> 12 in. (305 mm)

RELATIVE DENSITY / CONSISTENCY

COHESIONLESS SOILS		COHESIVE SOILS	
N, SPT, BLOWS/FT.	RELATIVE DENSITY	N, SPT, BLOWS/FT.	RELATIVE CONSISTENCY
< 4	Very loose	< 2	Very soft
4 - 10	Loose	2 - 4	Soft
10 - 30	Medium dense	4 - 8	Medium stiff
30 - 50	Dense	8 - 15	Stiff
> 50	Very dense	15 - 30	Very stiff
		> 30	Hard

WELL AND BACKFILL SYMBOLS



PERCENTAGES TERMS [1, 2]

Trace	< 5%
Few	5 to 10%
Little	15 to 25%
Some	30 to 45%
Mostly	50 to 100%

[1]Gravel, sand, and fines estimated by mass. Other constituents, such as organics, cobbles, and boulders, estimated by volume.

[2]Reprinted, with permission, from ASTM D2488 - 09a Standard Practice for Description and Identification of Soils (Visual-Manual Procedure), copyright ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA 19428. A copy of the complete standard may be obtained from ASTM International, www.astm.org.

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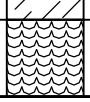
SOIL DESCRIPTION AND LOG KEY

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FIG. A-1
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2013_BORING_CLASS1_31-1-20006-001.GPJ_SHAN_WIL.GDT 6/1/17

UNIFIED SOIL CLASSIFICATION SYSTEM (USCS) (Modified From USACE Tech Memo 3-357, ASTM D2487, and ASTM D2488)					
MAJOR DIVISIONS			**GROUP/GRAPHIC SYMBOL**		**TYPICAL IDENTIFICATIONS**
COARSE-GRAINED SOILS *(more than 50% retained on No. 200 sieve)*	Gravels *(more than 50% of coarse fraction retained on No. 4 sieve)*	Gravel *(less than 5% fines)*	GW		Well-Graded Gravel; Well-Graded Gravel with Sand
			GP		Poorly Graded Gravel; Poorly Graded Gravel with Sand
		Silty or Clayey Gravel *(more than 12% fines)*	GM		Silty Gravel; Silty Gravel with Sand
			GC		Clayey Gravel; Clayey Gravel with Sand
	Sands *(50% or more of coarse fraction passes the No. 4 sieve)*	Sand *(less than 5% fines)*	SW		Well-Graded Sand; Well-Graded Sand with Gravel
			SP		Poorly Graded Sand; Poorly Graded Sand with Gravel
		Silty or Clayey Sand *(more than 12% fines)*	SM		Silty Sand; Silty Sand with Gravel
			SC		Clayey Sand; Clayey Sand with Gravel
FINE-GRAINED SOILS *(50% or more passes the No. 200 sieve)*	Silts and Clays *(liquid limit less than 50)*	Inorganic	ML		Silt; Silt with Sand or Gravel; Sandy or Gravelly Silt
			CL		Lean Clay; Lean Clay with Sand or Gravel; Sandy or Gravelly Lean Clay
		Organic	OL		Organic Silt or Clay; Organic Silt or Clay with Sand or Gravel; Sandy or Gravelly Organic Silt or Clay
	Silts and Clays *(liquid limit 50 or more)*	Inorganic	MH		Elastic Silt; Elastic Silt with Sand or Gravel; Sandy or Gravelly Elastic Silt
			CH		Fat Clay; Fat Clay with Sand or Gravel; Sandy or Gravelly Fat Clay
		Organic	OH		Organic Silt or Clay; Organic Silt or Clay with Sand or Gravel; Sandy or Gravelly Organic Silt or Clay
HIGHLY-ORGANIC SOILS	Primarily organic matter, dark in color, and organic odor		PT		Peat or other highly organic soils (see ASTM D4427)

NOTE: No. 4 size = 4.75 mm = 0.187 in.; No. 200 size = 0.075 mm = 0.003 in.

NOTES

1. Dual symbols *(symbols separated by a hyphen, i.e., SP-SM, Sand with Silt)* are used for soils with between 5% and 12% fines or when the liquid limit and plasticity index values plot in the CL-ML area of the plasticity chart. Graphics shown on the logs for these soil types are a combination of the two graphic symbols (e.g., SP and SM).

2. Borderline symbols *(symbols separated by a slash, i.e., CL/ML, Lean Clay to Silt; SP-SM/SM, Sand with Silt to Silty Sand)* indicate that the soil properties are close to the defining boundary between two groups.

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SOIL DESCRIPTION AND LOG KEY

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FIG. A-1
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2013_BORING_CLASS2_31-1-20006-001.GPJ_SHAN_WIL.GDT 6/1/17

GRADATION TERMS

Poorly Graded	Narrow range of grain sizes present or, within the range of grain sizes present, one or more sizes are missing (Gap Graded). Meets criteria in ASTM D2487, if tested.
Well-Graded	Full range and even distribution of grain sizes present. Meets criteria in ASTM D2487, if tested.

CEMENTATION TERMS[1]

Weak	Crumbles or breaks with handling or slight finger pressure.
Moderate	Crumbles or breaks with considerable finger pressure.
Strong	Will not crumble or break with finger pressure.

PLASTICITY[2]

DESCRIPTION	VISUAL-MANUAL CRITERIA	APPROX. PLASITICITY INDEX RANGE
Nonplastic	A 1/8-in. thread cannot be rolled at any water content.	< 4
Low	A thread can barely be rolled and a lump cannot be formed when drier than the plastic limit.	4 to 10
Medium	A thread is easy to roll and not much time is required to reach the plastic limit. The thread cannot be rerolled after reaching the plastic limit. A lump crumbles when drier than the plastic limit.	10 to 20
High	It takes considerable time rolling and kneading to reach the plastic limit. A thread can be rerolled several times after reaching the plastic limit. A lump can be formed without crumbling when drier than the plastic limit.	> 20

ADDITIONAL TERMS

Mottled	Irregular patches of different colors.
Bioturbated	Soil disturbance or mixing by plants or animals.
Diamict	Nonsorted sediment; sand and gravel in silt and/or clay matrix.
Cuttings	Material brought to surface by drilling.
Slough	Material that caved from sides of borehole.
Sheared	Disturbed texture, mix of strengths.

PARTICLE ANGULARITY AND SHAPE TERMS[1]

Angular	Sharp edges and unpolished planar surfaces.
Subangular	Similar to angular, but with rounded edges.
Subrounded	Nearly planar sides with well-rounded edges.
Rounded	Smoothly curved sides with no edges.
Flat	Width/thickness ratio > 3.
Elongated	Length/width ratio > 3.

ACRONYMS AND ABBREVIATIONS

ATD	At Time of Drilling
Diam.	Diameter
Elev.	Elevation
ft.	Feet
FeO	Iron Oxide
gal.	Gallons
Horiz.	Horizontal
HSA	Hollow Stem Auger
I.D.	Inside Diameter
in.	Inches
lbs.	Pounds
MgO	Magnesium Oxide
mm	Millimeter
MnO	Manganese Oxide
NA	Not Applicable or Not Available
NP	Nonplastic
O.D.	Outside Diameter
OW	Observation Well
pcf	Pounds per Cubic Foot
PID	Photo-Ionization Detector
PMT	Pressuremeter Test
ppm	Parts per Million
psi	Pounds per Square Inch
PVC	Polyvinyl Chloride
rpm	Rotations per Minute
SPT	Standard Penetration Test
USCS	Unified Soil Classification System
q_u	Unconfined Compressive Strength
VWP	Vibrating Wire Piezometer
Vert.	Vertical
WOH	Weight of Hammer
WOR	Weight of Rods
Wt.	Weight

STRUCTURE TERMS[1]

Interbedded	Alternating layers of varying material or color with layers at least 1/4-inch thick; singular: bed.
Laminated	Alternating layers of varying material or color with layers less than 1/4-inch thick; singular: lamination.
Fissured	Breaks along definite planes or fractures with little resistance.
Slickensided	Fracture planes appear polished or glossy; sometimes striated.
Blocky	Cohesive soil that can be broken down into small angular lumps that resist further breakdown.
Lensed	Inclusion of small pockets of different soils, such as small lenses of sand scattered through a mass of clay.
Homogeneous	Same color and appearance throughout.

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SOIL DESCRIPTION AND LOG KEY

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FIG. A-1
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2013_BORING_CLASS3_31-1-20006-001.GPJ_SHAN_WIL.GDT 6/1/17

Total Depth:	61.5 ft.	Northing:		Drilling Method:	Hollow Stem Auger	Hole Diam.:	8 in.
Top Elevation:	~	Easting:		Drilling Company:	Homestead Drilling	Rod Diam.:	
Vert. Datum:	NAD 83, Zone 3	Station:		Drill Rig Equipment:	B61 Tracked Rig	Hammer Type:	Automatic
Horiz. Datum:	NAD 83, Zone 3	Offset:		Other Comments:			

SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

Gray-brown, *Poorly Graded Gravel with Sand (GP)*; moist.

2.0

Loose, gray-brown, *Sandy Silt (ML)*; moist; trace organics.

8.5

Loose, gray-brown, *Silty Sand (SM)*; moist; trace organics.

9.5

Loose to medium-dense, gray-brown, *Poorly Graded Gravel with Silt and Sand (GP-GM) to Well-Graded Gravel with Sand (GW) to Poorly Graded Gravel with Sand (GP)*; moist to 12.0 feet, wet below 12.0 feet; fractured gravel up to 3 inches present in some samples.

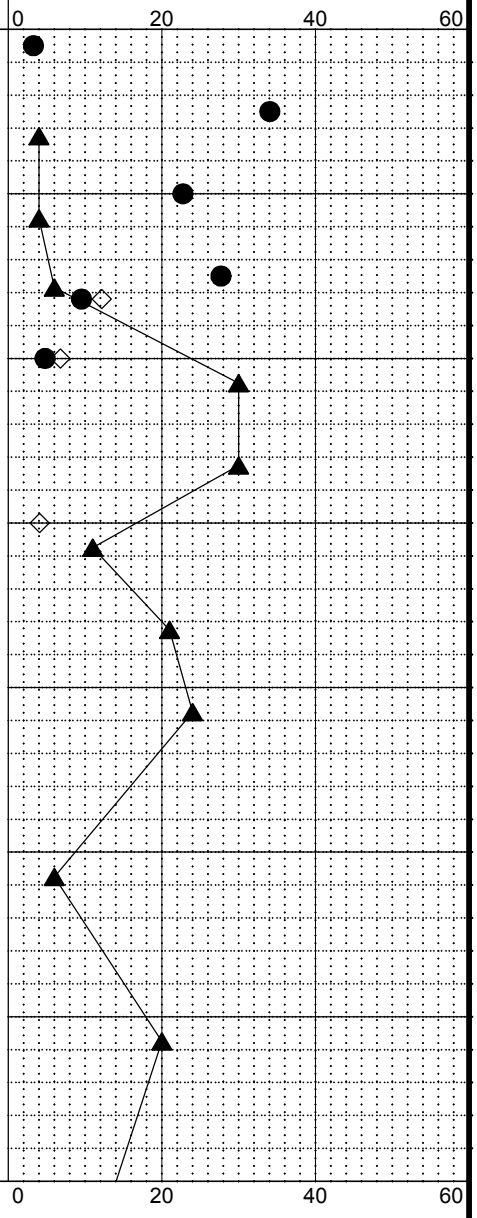
CONTINUED NEXT SHEET

Depth, ft.	PID, ppm	Samples
	0.6	1
	0.3	2
	0.6	3
	0.4	4a
	0.6	4b
	0.6	5
		6
		7
		8
		9
		10
		11

Ground Water Depth, ft.: During Drilling ▽

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: 300 lbs / 30 inches



LEGEND

* Sample Not Recovered

▽ Ground Water Level ATD

Grab Sample

3" O.D. Split Spoon Sample

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-01

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

FIG. A-2
Sheet 1 of 2

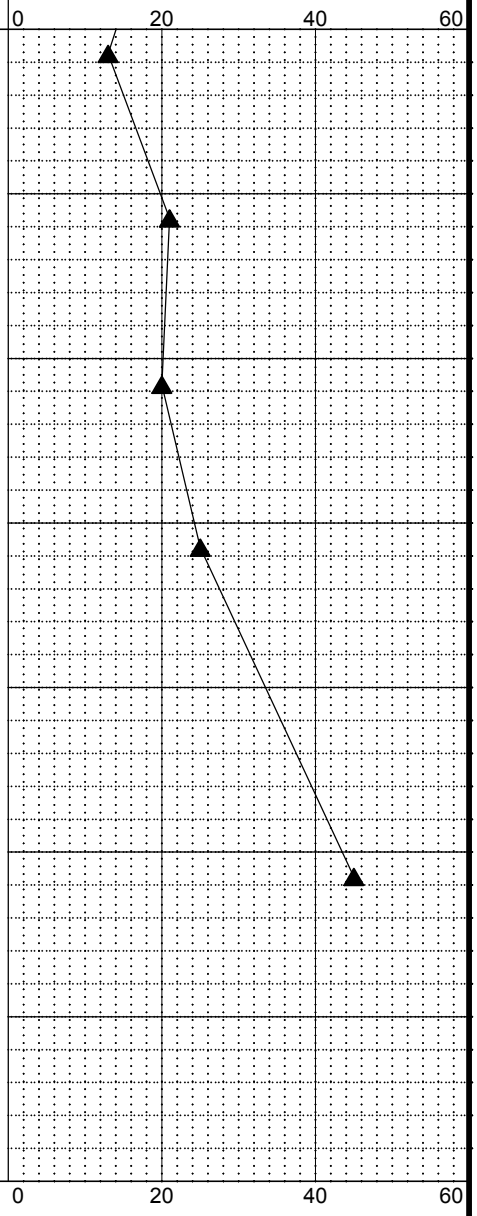
MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/4/17 Rev: IAS Typ: Dym Pxg

Total Depth:	*61.5 ft.*	Northing:		Drilling Method:	*Hollow Stem Auger*	Hole Diam.:	*8 in.*
Top Elevation:	*~*	Easting:		Drilling Company:	*Homestead Drilling*	Rod Diam.:	
Vert. Datum:	*NAD 83, Zone 3*	Station:		Drill Rig Equipment:	*B61 Tracked Rig*	Hammer Type:	*Automatic*
Horiz. Datum:	*NAD 83, Zone 3*	Offset:		Other Comments:			

SOIL DESCRIPTION	Depth, ft.	Symbol	PID, ppm	Samples	Ground Water	Depth, ft.
Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.						
				12		
				13		
				14		
				15		
				16		
BOTTOM OF BORING BORING COMPLETED 5/15/2017	61.5					

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: *300 lbs / 30 inches*



LEGEND

* Sample Not Recovered

Grab Sample

3" O.D. Split Spoon Sample

▽ Ground Water Level ATD

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-01

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

FIG. A-2
Sheet 2 of 2

MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/27/17 Rev: IAS Typ: Dym

Total Depth:	61.5 ft.	Northing:		Drilling Method:	Hollow Stem Auger	Hole Diam.:	8 in.
Top Elevation:	~	Easting:		Drilling Company:	Homestead Drilling	Rod Diam.:	
Vert. Datum:	NAD 83, Zone 3	Station:		Drill Rig Equipment:	B61 Tracked Rig	Hammer Type:	Automatic
Horiz. Datum:	NAD 83, Zone 3	Offset:		Other Comments:			

SOIL DESCRIPTION	Depth, ft.
Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.	
Brown, *Poorly Graded Sand with Silt (SP-SM)*; moist; trace gravel.	
Gray-brown, *Well-Graded Gravel with Silt and Sand (GW-GM)*; wet to 3.5 feet; frozen, Nbn from 3.5 feet to 4.5 feet.	2.0
Loose to medium-dense, gray-brown, *Poorly Graded Gravel with Sand (GP)*; wet; trace fines.	4.5
Loose to medium-dense, gray-brown, *Poorly Graded Sand (SP)*; wet; trace to few gravel, trace fines.	12.0
Loose to dense, gray-brown, *Poorly Graded Gravel with Sand (GP)*; wet; gravel up to 3 inches present in sample 12; trace fines.	17.0

Frozen =

Symbol

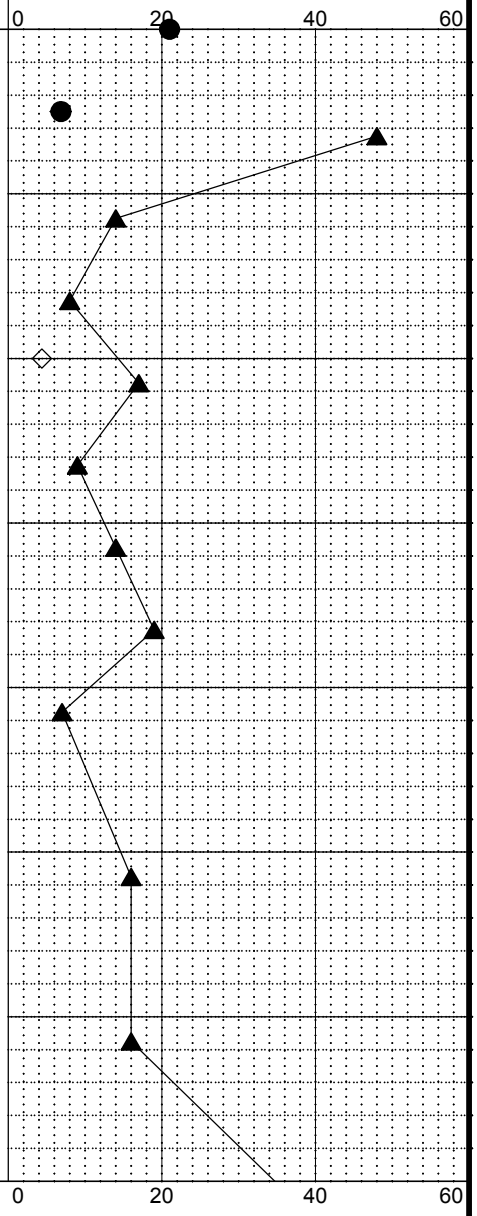
PID, ppm: 0.2, 0.1, 0.3

Samples: 1 (G), 2, 3, 4, 5, 6, 7, 8, 9, 10, 11

Ground Water Depth, ft.: During Drilling ▽

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: *300 lbs / 30 inches*



CONTINUED NEXT SHEET

LEGEND

* Sample Not Recovered

▽ Ground Water Level ATD

Grab Sample

3" O.D. Split Spoon Sample

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-02

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

FIG. A-3
Sheet 1 of 2

MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/27/17 Rev: IAS Typ: Dym

Total Depth:	*61.5 ft.*	Northing:		Drilling Method:	*Hollow Stem Auger*	Hole Diam.:	*8 in.*
Top Elevation:	*~*	Easting:		Drilling Company:	*Homestead Drilling*	Rod Diam.:	
Vert. Datum:	*NAD 83, Zone 3*	Station:		Drill Rig Equipment:	*B61 Tracked Rig*	Hammer Type:	*Automatic*
Horiz. Datum:	*NAD 83, Zone 3*	Offset:		Other Comments:			

SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

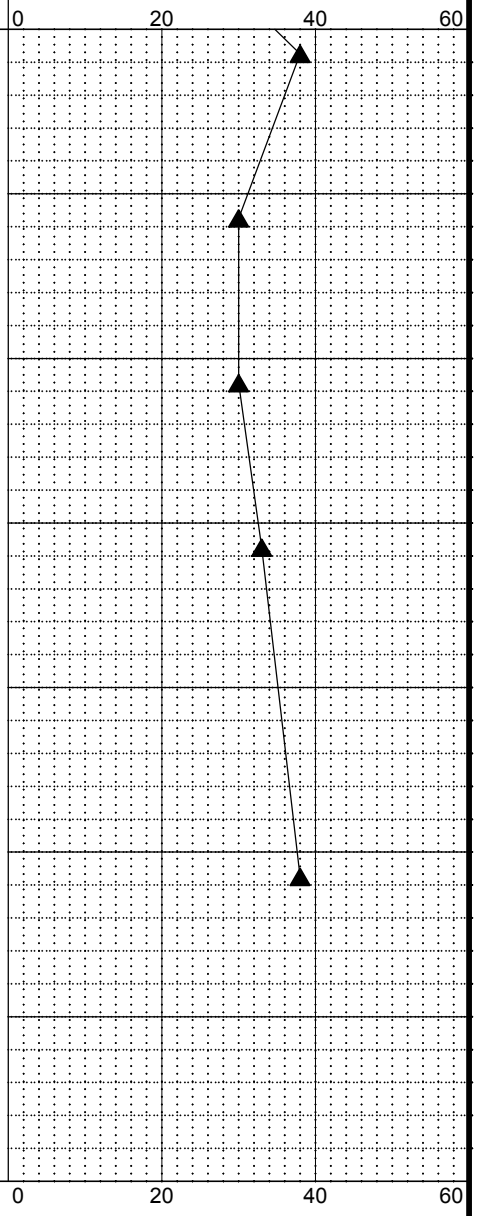
Frozen = ■

Depth, ft.	Symbol	PID, ppm	Samples	Ground Water	Depth, ft.
61.5			12, 13, 14, 15, 16		

BOTTOM OF BORING
BORING COMPLETED 5/16/2017

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: *300 lbs / 30 inches*



LEGEND

* Sample Not Recovered
Grab Sample
3" O.D. Split Spoon Sample
▽ Ground Water Level ATD

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
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North Pole, Alaska

LOG OF BORING 17-02

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

FIG. A-3
Sheet 2 of 2

MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/27/17 Rev: IAS Typ: Dym

Total Depth:	61.5 ft.	Northing:		Drilling Method:	Hollow Stem Auger	Hole Diam.:	8 in.
Top Elevation:	~	Easting:		Drilling Company:	Homestead Drilling	Rod Diam.:	
Vert. Datum:	NAD 83, Zone 3	Station:		Drill Rig Equipment:	B61 Tracked Rig	Hammer Type:	Automatic
Horiz. Datum:	NAD 83, Zone 3	Offset:		Other Comments:			

SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

Frozen =

Gray-brown, *Poorly Graded Sand with Silt (SP-SM)*; moist to 2.0 feet; frozen, Nbn to Nf from 2.0 feet to 4.5 feet.

4.5

Loose, gray-brown, *Poorly Graded Sand with Silt (SP-SM)*; moist.

7.0

Loose to dense, gray-brown, *Well-Graded Gravel with Sand (GW) to Poorly Graded Gravel with Sand (GP)*; moist to 7.0 feet, wet below 7.0 feet; fractured gravel up to 3 inches present in some samples; trace fines.

CONTINUED NEXT SHEET

Depth, ft. | Symbol | PID, ppm | Samples | Ground Water Depth, ft.

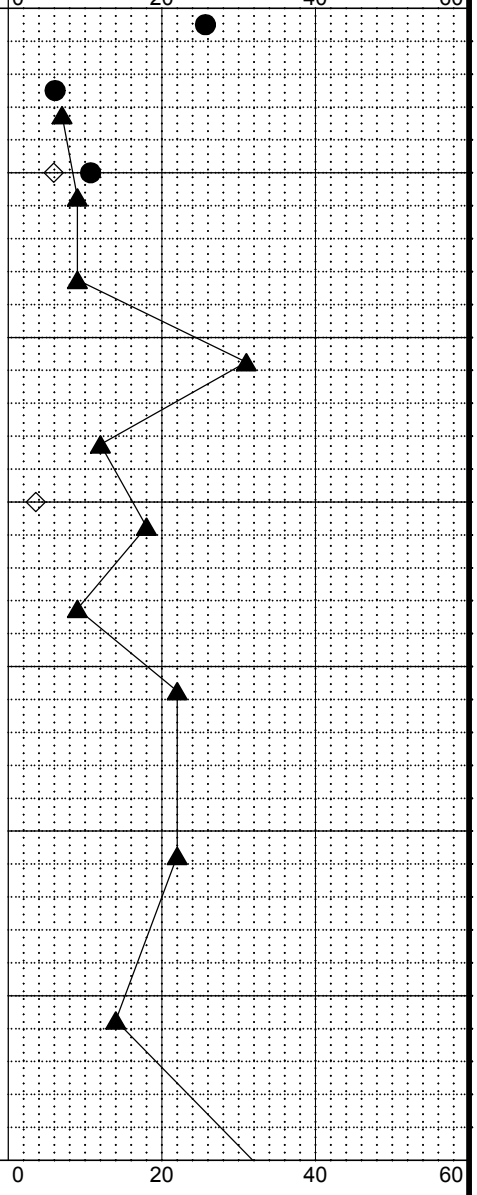
PID, ppm: 0.3, 0.6, 0.2, 0.4

Samples: 1 (G), 2, 3, 4, 5, 6, 7, 8, 9, 10, 11

During Drilling ▽

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: 300 lbs / 30 inches



LEGEND

* Sample Not Recovered

Grab Sample

3" O.D. Split Spoon Sample

▽ Ground Water Level ATD

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-03

June 2017 31-1-20006-001R1

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FIG. A-4
Sheet 1 of 2

MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/4/17 Rev: IAS Typ: Dym

Total Depth:	*61.5 ft.*	Northing:		Drilling Method:	*Hollow Stem Auger*	Hole Diam.:	*8 in.*
Top Elevation:	*~*	Easting:		Drilling Company:	*Homestead Drilling*	Rod Diam.:	
Vert. Datum:	*NAD 83, Zone 3*	Station:		Drill Rig Equipment:	*B61 Tracked Rig*	Hammer Type:	*Automatic*
Horiz. Datum:	*NAD 83, Zone 3*	Offset:		Other Comments:			

SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

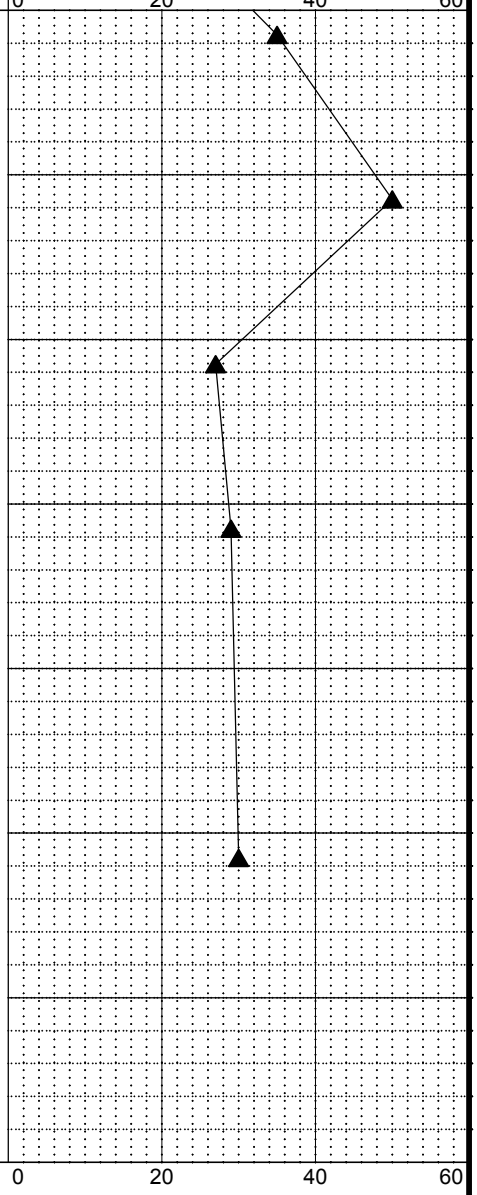
Frozen = ■

Depth, ft.	Symbol	PID, ppm	Samples	Ground Water	Depth, ft.
61.5			12, 13, 14, 15, 16		

BOTTOM OF BORING
BORING COMPLETED 5/17/2017

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: *300 lbs / 30 inches*



◇ % Fines (<0.075mm)
● % Water Content

LEGEND

* Sample Not Recovered
Grab Sample
3" O.D. Split Spoon Sample
Ground Water Level ATD

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

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North Pole, Alaska

LOG OF BORING 17-03

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SHANNON & WILSON, INC.
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FIG. A-4
Sheet 2 of 2

MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/27/17 Rev: IAS Typ: Dym

Total Depth:	61.5 ft.	Northing:		Drilling Method:	Hollow Stem Auger	Hole Diam.:	8 in.
Top Elevation:	~	Easting:		Drilling Company:	Homestead Drilling	Rod Diam.:	
Vert. Datum:	NAD 83, Zone 3	Station:		Drill Rig Equipment:	B61 Tracked Rig	Hammer Type:	Automatic
Horiz. Datum:	NAD 83, Zone 3	Offset:		Other Comments:			

SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

Frozen =

Gray-brown, *Sandy Silt (ML)*; moist to 1.0 foot; frozen, Nbn from 1.0 foot to 2.5 feet; trace to few organics.

2.5

Loose, gray-brown, *Silty Sand (SM)*; moist.

6.0

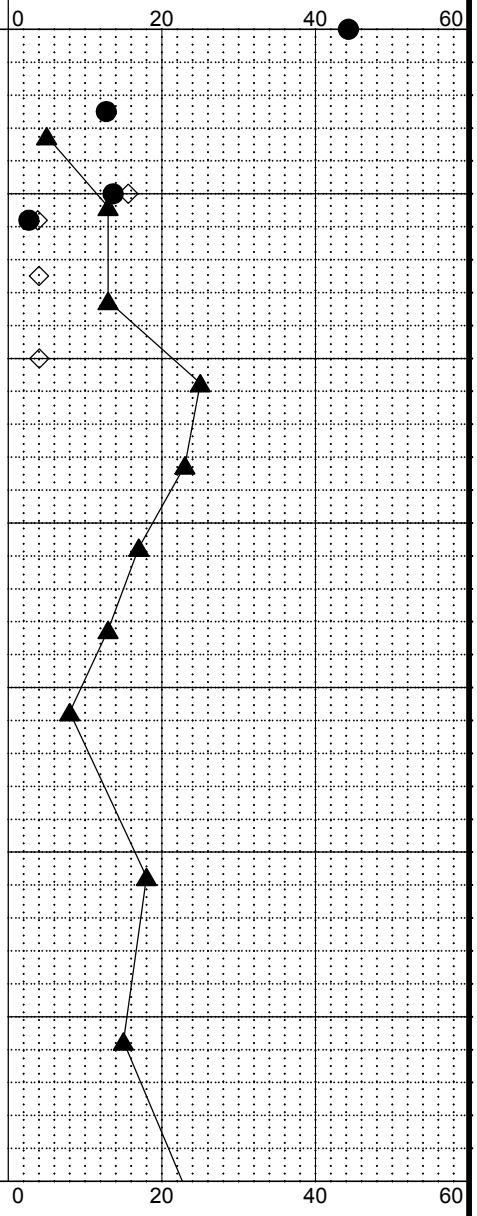
Loose to dense, gray-brown, *Poorly Graded Gravel with Sand (GP)*; moist to 7.0 feet, wet below 7.0 feet; gravel up to 3 inches present in many samples; trace fines.

CONTINUED NEXT SHEET

Depth, ft.	Symbol	PID, ppm	Samples	Ground Water Depth, ft.
		0.7	1 G	
		0.5	2	
		0.6	3a	
		0.7	3b	
		0.6	4	During Drilling ▽
			5	
			6	
			7	
			8	
			9	
			10	
			11	

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: 300 lbs / 30 inches



LEGEND

* Sample Not Recovered

G Grab Sample

3" O.D. Split Spoon Sample

▽ Ground Water Level ATD

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
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North Pole, Alaska

LOG OF BORING 17-04

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

FIG. A-5
Sheet 1 of 2

MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/4/17 Pxg Rev: IAS Typ: Dym

Total Depth:	*61.5 ft.*	Northing:		Drilling Method:	*Hollow Stem Auger*	Hole Diam.:	*8 in.*
Top Elevation:	*~*	Easting:		Drilling Company:	*Homestead Drilling*	Rod Diam.:	
Vert. Datum:	*NAD 83, Zone 3*	Station:		Drill Rig Equipment:	*B61 Tracked Rig*	Hammer Type:	*Automatic*
Horiz. Datum:	*NAD 83, Zone 3*	Offset:		Other Comments:			

SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

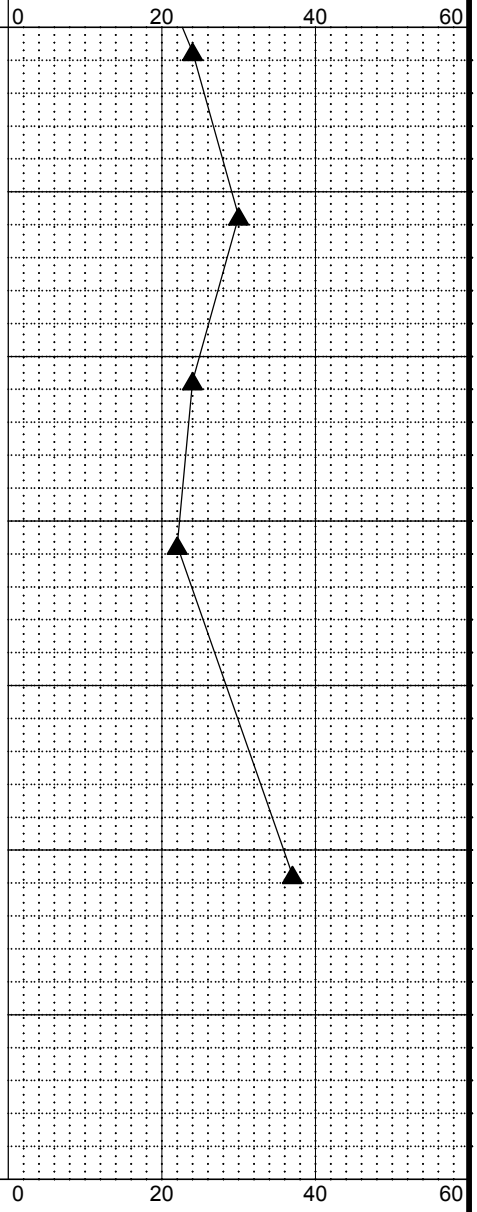
Frozen = ■

Depth, ft.	Symbol	PID, ppm	Samples	Ground Water Depth, ft.
61.5			12, 13, 14, 15, 16	

BOTTOM OF BORING
BORING COMPLETED 5/17/2017

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: *300 lbs / 30 inches*



LEGEND

* Sample Not Recovered
Grab Sample
3" O.D. Split Spoon Sample
▽ Ground Water Level ATD

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-04

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

FIG. A-5
Sheet 2 of 2

MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/27/17 Rev: IAS Typ: Dym

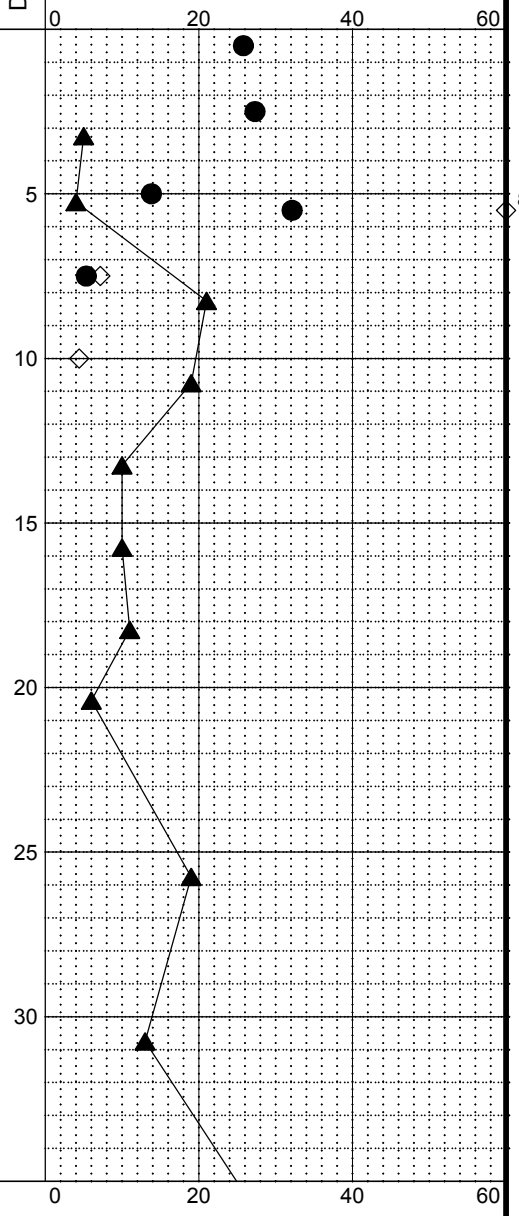
Total Depth:	61.5 ft.	Northing:		Drilling Method:	Hollow Stem Auger	Hole Diam.:	8 in.
Top Elevation:	~	Easting:		Drilling Company:	Homestead Drilling	Rod Diam.:	
Vert. Datum:	NAD 83, Zone 3	Station:		Drill Rig Equipment:	B61 Tracked Rig	Hammer Type:	Automatic
Horiz. Datum:	NAD 83, Zone 3	Offset:		Other Comments:			

SOIL DESCRIPTION	Depth, ft.	Symbol	PID, ppm	Samples
Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual. Frozen =				
Gray-brown, *Silt with Sand (ML)*; moist to 1 foot; frozen, Nbn from 1 foot to 2.5 feet; trace organics.			1.3	1 G
	2.5			
Loose, gray-brown to gray, *Silt with Sand (ML) to Silty Sand (SM)*; moist; trace organics to 4.5 feet.			0.7	2
			0.8	3a
			0.7	3b
	7.5			
Loose to medium-dense, gray-brown, *Poorly Graded Gravel with Silt and Sand (GP-GM) to Poorly Graded Gravel with Sand (GP)*; moist to 9.5 feet, wet below 9.5 feet.			1	4
			0.2	5
				6
				7
				8
	21.0			9a
				9b
Loose, gray-brown, *Poorly Graded Sand (SP)*; wet; trace fines.				
	23.0			
Medium-dense to dense, gray-brown, *Poorly Graded Gravel with Sand (GP)*; wet; coarse, subangular to subrounded gravel; trace fines.				10
				11

Ground Water Depth, ft. — During Drilling ▽

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: *300 lbs / 30 inches*



CONTINUED NEXT SHEET

LEGEND

* Sample Not Recovered
G Grab Sample
3" O.D. Split Spoon Sample
▽ Ground Water Level ATD

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
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North Pole, Alaska

LOG OF BORING 17-05

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

FIG. A-6
Sheet 1 of 2

MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/4/17 Pxg Rev: IAS Typ: Dym

REV 3 - Approved for Submittal

Total Depth:	61.5 ft.	Northing:		Drilling Method:	Hollow Stem Auger	Hole Diam.:	8 in.
Top Elevation:	~	Easting:		Drilling Company:	Homestead Drilling	Rod Diam.:	
Vert. Datum:	NAD 83, Zone 3	Station:		Drill Rig Equipment:	B61 Tracked Rig	Hammer Type:	Automatic
Horiz. Datum:	NAD 83, Zone 3	Offset:		Other Comments:			

SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

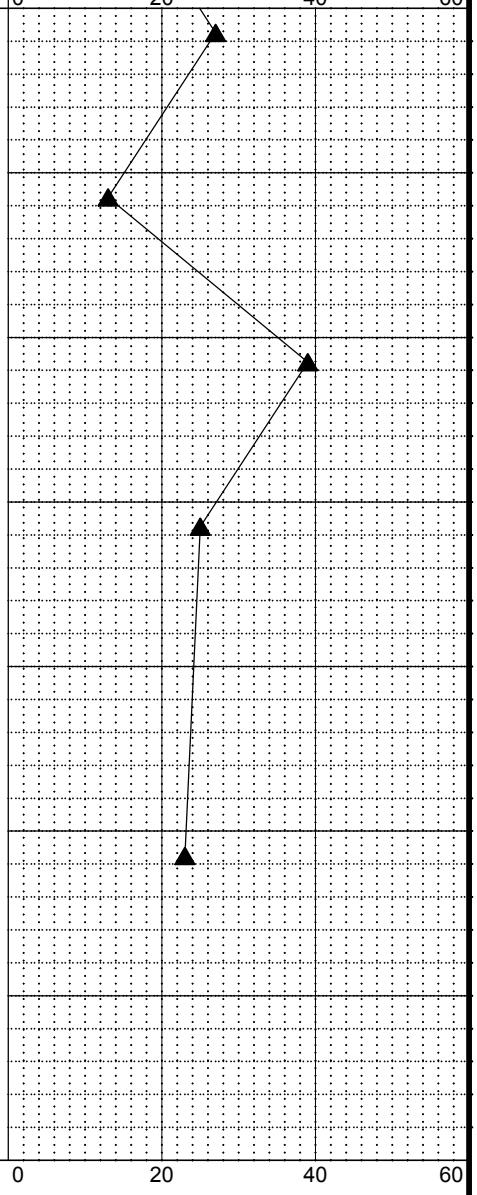
Frozen = ■

Depth, ft.	Symbol	PID, ppm	Samples	Ground Water Depth, ft.
61.5			12, 13, 14, 15, 16	

BOTTOM OF BORING
BORING COMPLETED 5/18/2017

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: 300 lbs / 30 inches



LEGEND

* Sample Not Recovered
Grab Sample
3" O.D. Split Spoon Sample
▽ Ground Water Level ATD

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

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GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-05

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SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

FIG. A-6
Sheet 2 of 2

MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/27/17 Rev: IAS Typ: Dym

APPENDIX B

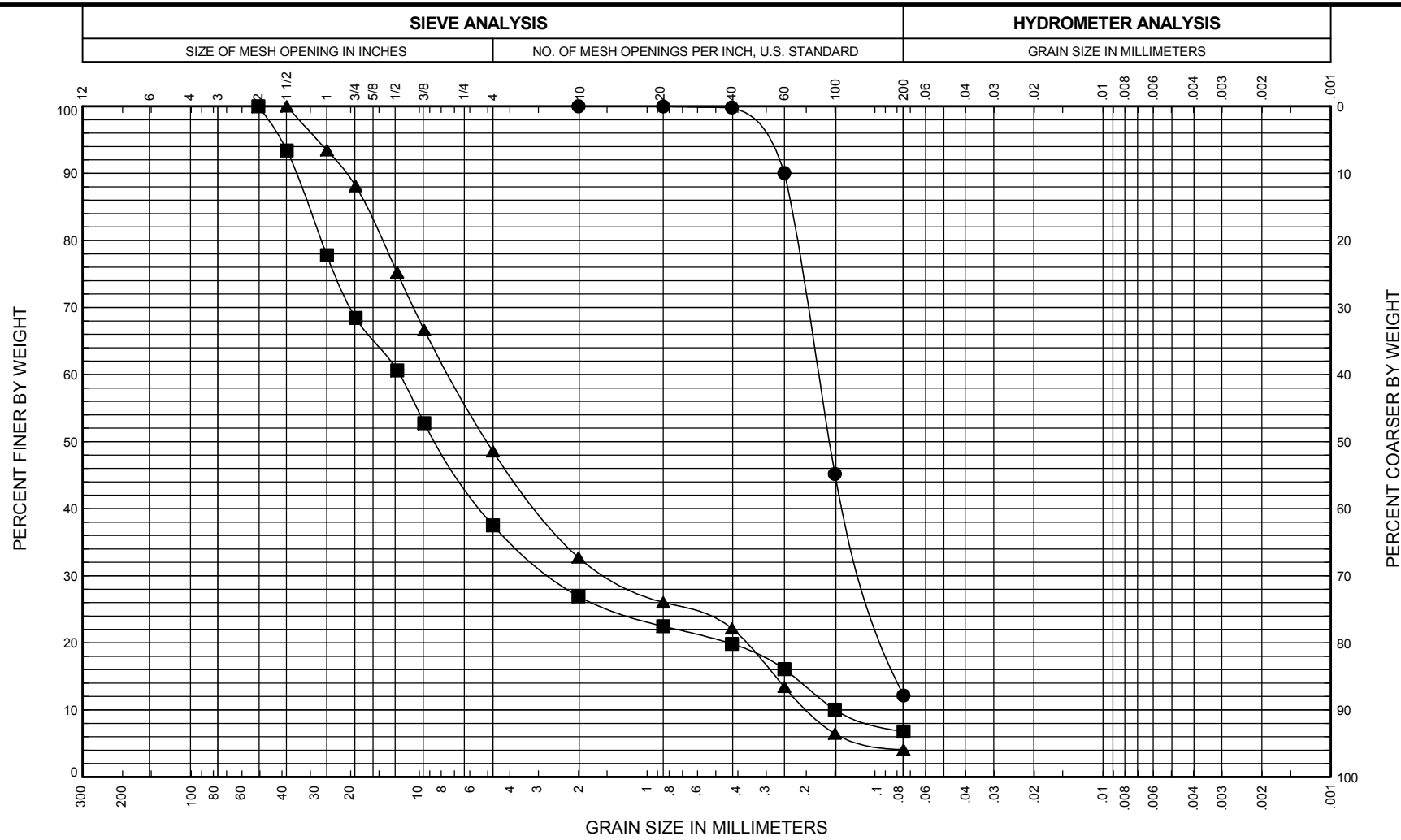
GRAIN SIZE DISTRIBUTIONS

APPENDIX B

GRAIN SIZE DISTRIBUTIONS

FIGURES

B-1 Grain Size Distribution; Boring 17-01
B-2 Grain Size Distribution; Boring 17-02
B-3 Grain Size Distribution; Boring 17-03
B-4 Grain Size Distribution; Boring 17-04
B-5 Grain Size Distribution; Boring 17-05



BORING AND SAMPLE NO.	DEPTH (feet)	U.S.C.S. SYMBOL	SOIL CLASSIFICATION	COBBLE %	GRAVEL %	SAND %	FINES %	NAT. W.C. %	TEST BY	REVIEW BY	ASTM STD
● 17-01, 4b	8.2	SM	Silty Sand			88	12.2	9.5	SLD	AMV	C136
■ 17-01, S-5*	10.0	GP-GM	Poorly Graded Gravel with Silt and Sand		62	31	6.8	4.8	ALW	AMV	C136
▲ 17-01, S-7*	15.0	GW	Well-Graded Gravel with Sand		51	44	4.1		ALW	AMV	C136

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GVEA Fuel Storage Facility
North Pole, Alaska

GRAIN SIZE DISTRIBUTION
BORING 17-01

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

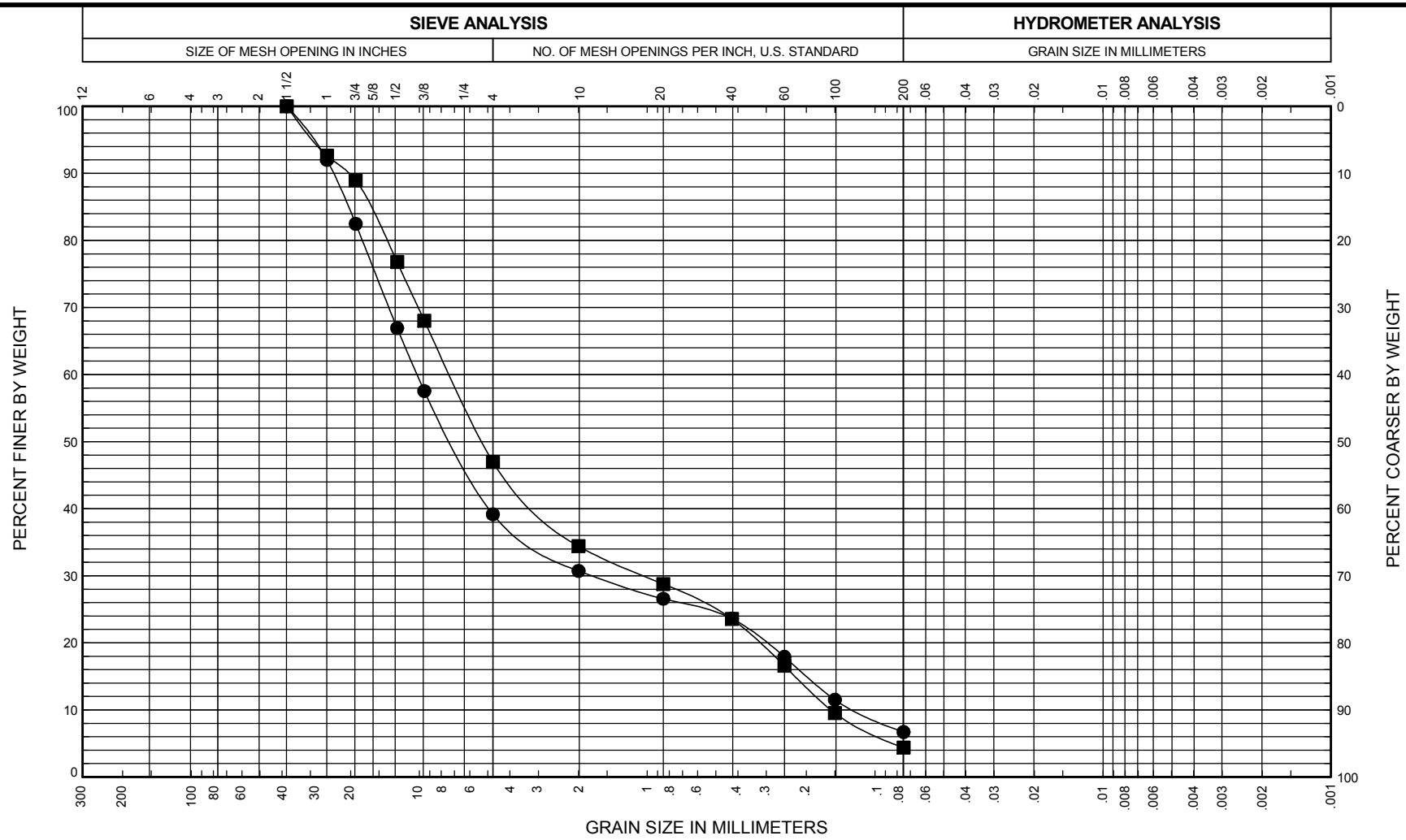
FIG. B-1
Sheet 1 of 1

FIG. B-1

** Sample specimen weight did not meet required minimum mass for ASTM test method.*

PDC Engineers, Inc.

AASHTO GSA MAIN 31-1-20006-001.GPJ SHAN WIL.GDT 6/1/17



BORING AND SAMPLE NO.	DEPTH (feet)	U.S.C.S. SYMBOL	SOIL CLASSIFICATION	COBBLE %	GRAVEL %	SAND %	FINES %	NAT. W.C. %	TEST BY	REVIEW BY	ASTM STD
● 17-02, S-2*	2.5	GW-GM	Well-Graded Gravel with Silt and Sand		61	32	6.7	6.9	EJB	AMV	C136
■ 17-02, S-5*	10.0	GP	Poorly Graded Gravel with Sand		53	43	4.4		EJB	AMV	C136

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GRAIN SIZE DISTRIBUTION
BORING 17-02

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

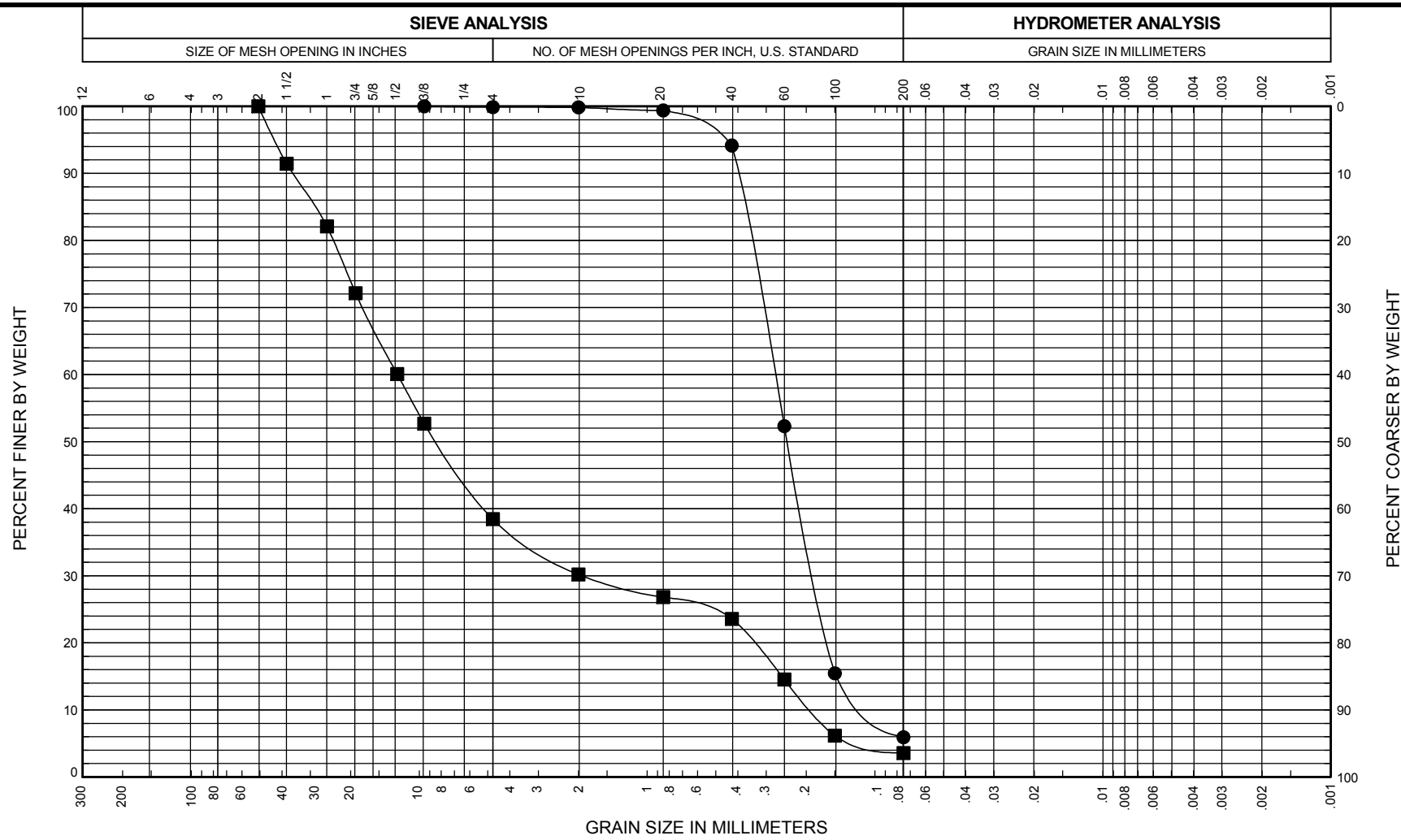
FIG. B-2
Sheet 1 of 1

FIG. B-2

** Sample specimen weight did not meet required minimum mass for ASTM test method.*

PDC Engineers, Inc.

AASHTO GSA MAIN 31-1-20006-001.GPJ SHAN WIL.GDT 6/1/17



BORING AND SAMPLE NO.	DEPTH (feet)	U.S.C.S. SYMBOL	SOIL CLASSIFICATION	COBBLE %	GRAVEL %	SAND %	FINES %	NAT. W.C. %	TEST BY	REVIEW BY	ASTM STD
● 17-03, S-3	5.0	SP-SM	Poorly Graded Sand with Silt		0	94	5.9	10.7	ALW	AMV	C136
■ 17-03, S-7*	15.0	GW	Well-Graded Gravel with Sand		62	35	3.6		ALW	AMV	C136

** Sample specimen weight did not meet required minimum mass for ASTM test method.*

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

GRAIN SIZE DISTRIBUTION
BORING 17-03

June 2017 31-1-20006-001R1

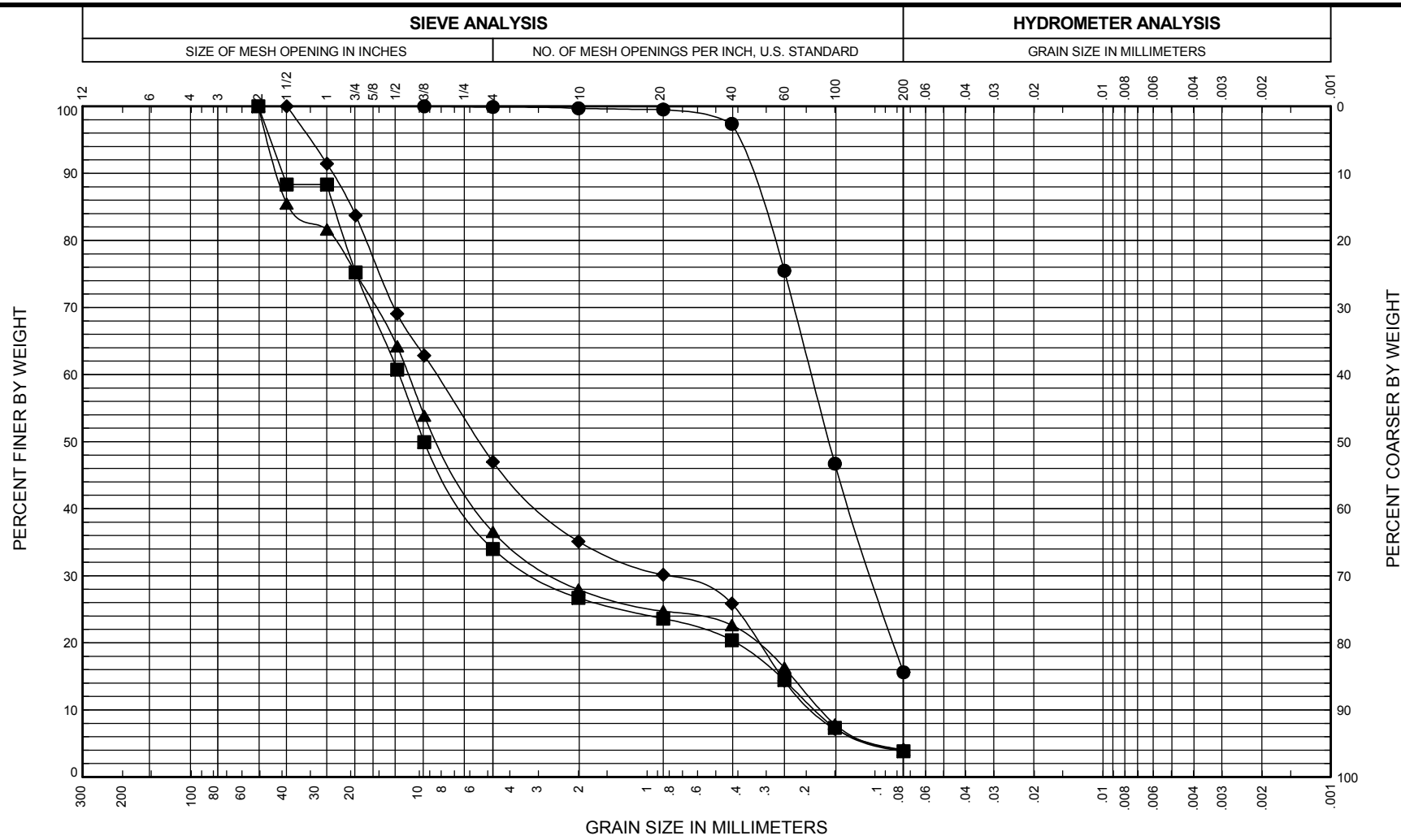
SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

FIG. B-3
Sheet 1 of 1

FIG. B-3

PDC Engineers, Inc.

AASHTO GSA MAIN 31-1-20006-001.GPJ SHAN WIL.GDT 6/1/17



BORING AND SAMPLE NO.	DEPTH (feet)	U.S.C.S. SYMBOL	SOIL CLASSIFICATION	COBBLE %	GRAVEL %	SAND %	FINES %	NAT. W.C. %	TEST BY	REVIEW BY	ASTM STD
● 17-04, 3a*	5.0	SM	Silty Sand		0	84	15.6	13.7	EJB	AMV	C136
■ 17-04, 3b*	5.8	GP	Poorly Graded Gravel with Sand		66	30	3.8	2.7	EJB	AMV	C136
▲ 17-04, S-4*	7.5	GP	Poorly Graded Gravel with Sand		63	33	4.0		EJB	AMV	C136
◆ 17-04, S-5*	10.0	GP	Poorly Graded Gravel with Sand		53	43	4.0		EJB	AMV	C136

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

GRAIN SIZE DISTRIBUTION
BORING 17-04

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

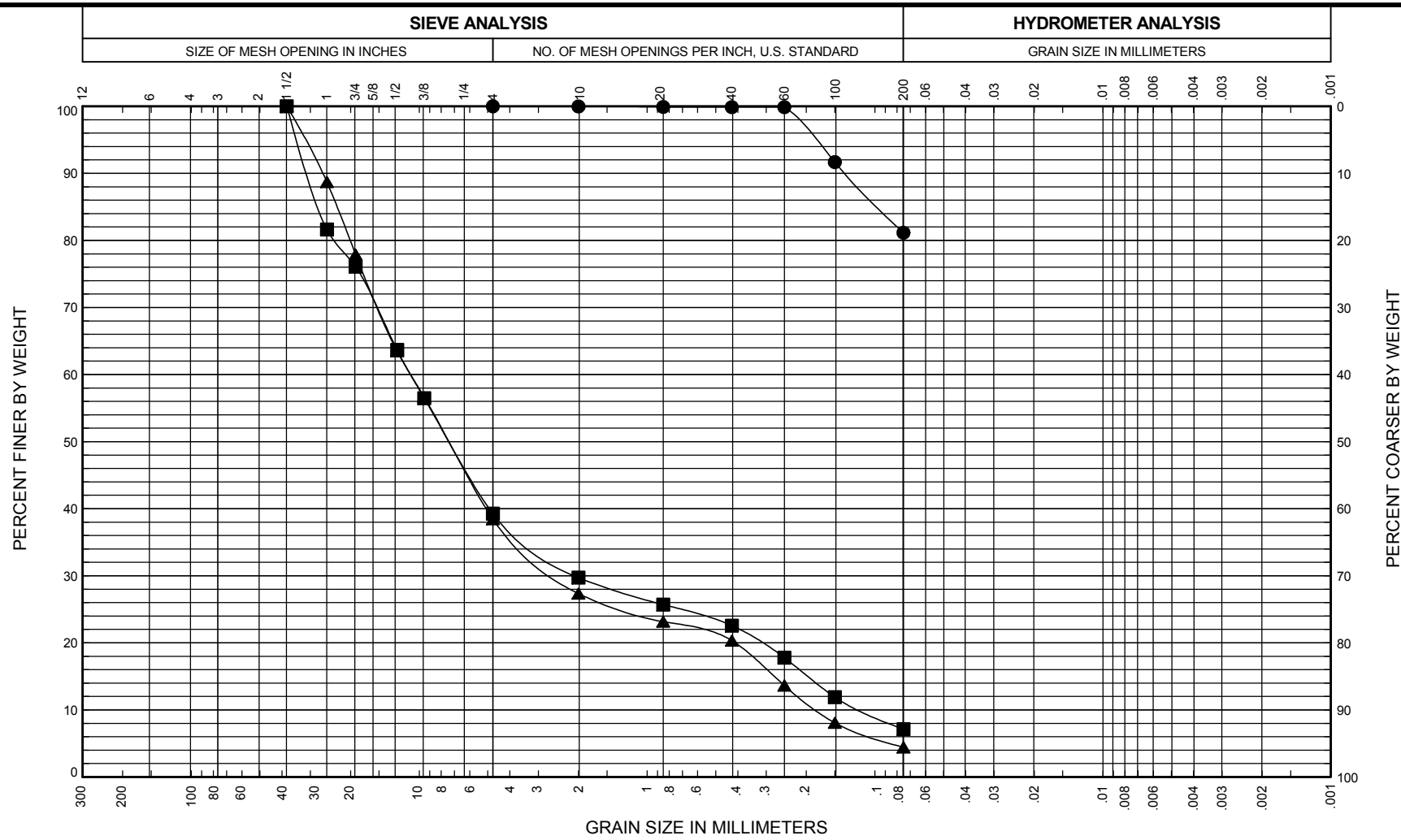
FIG. B-4
Sheet 1 of 1

FIG. B-4

** Sample specimen weight did not meet required minimum mass for ASTM test method.*

PDC Engineers, Inc.

AASHTO GSA MAIN 31-1-20006-001.GPJ SHAN WIL.GDT 6/1/17



BORING AND SAMPLE NO.	DEPTH (feet)	U.S.C.S. SYMBOL	SOIL CLASSIFICATION	COBBLE %	GRAVEL %	SAND %	FINES %	NAT. W.C. %	TEST BY	REVIEW BY	ASTM STD
● 17-05, 3b	5.5	ML	Silt with Sand			19	81.1	32.1	EJB	AMV	C136
■ 17-05, S-4*	7.5	GP-GM	Poorly Graded Gravel with Silt and Sand		61	32	7.1	5.3	ALW	AMV	C136
▲ 17-05, S-5*	10.0	GP	Poorly Graded Gravel with Sand		62	34	4.4		ALW	AMV	C136

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

GRAIN SIZE DISTRIBUTION
BORING 17-05

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

FIG. B-5
Sheet 1 of 1

FIG. B-5

** Sample specimen weight did not meet required minimum mass for ASTM test method.*

PDC Engineers, Inc.

AASHTO GSA MAIN 31-1-20006-001.GPJ SHAN WIL.GDT 6/1/17

APPENDIX C

PROJECT PHOTOGRAPHS



Photograph 1: Drill rig set up at boring location 17-01.



Photograph 2: Sample S-2, boring 17-01, 2.5 feet bgs to 4.0 feet bgs.



Photograph 3: Sample S-4a and S4-b, boring 17-01, 7.5 feet bgs to 9.0 feet bgs.



Photograph 4: Sample S-8, boring 17-01, 17.5 feet bgs to 19.0 feet bgs.



Photograph 5: Sample S-13, boring 17-01, 40.0 feet bgs to 41.5 feet bgs.



Photograph 6: Sample S-16, boring 17-01, 60 feet bgs to 61.5 feet bgs.



Photograph 7: Drill rig set up at boring 17-02.



Photograph 8: Sample S-2, boring 17-02, 2.5 feet bgs to 4.0 feet bgs.



Photograph 9: Sample 3, boring 17-02, 7.5 feet bgs to 9.0 feet bgs.



Photograph 10: Sample S-8, boring 17-02, 17.5 feet bgs to 19.0 feet bgs.



Photograph 11: Sample S-12, boring 17-02, 35.0 feet bgs to 36.5 feet bgs.



Photograph 12: Sample S-16, boring 17-02, 60.0 feet bgs to 61.5 feet bgs.



Photograph 13: Drill rig set up at boring 17-03.



Photograph 16: Sample S-13, boring 17-03, 40.0 feet bgs to 41.5 feet bgs.



Photograph 14: Sample S-2, boring 17-03, 2.5 feet bgs to 4.0 feet bgs.



Photograph 17: Sample S-16, boring 17-03, 60.0 feet bgs to 61.5 feet bgs.



Photograph 15: Sample S-10, boring 17-01, 25.0 feet bgs to 26.5 feet bgs.



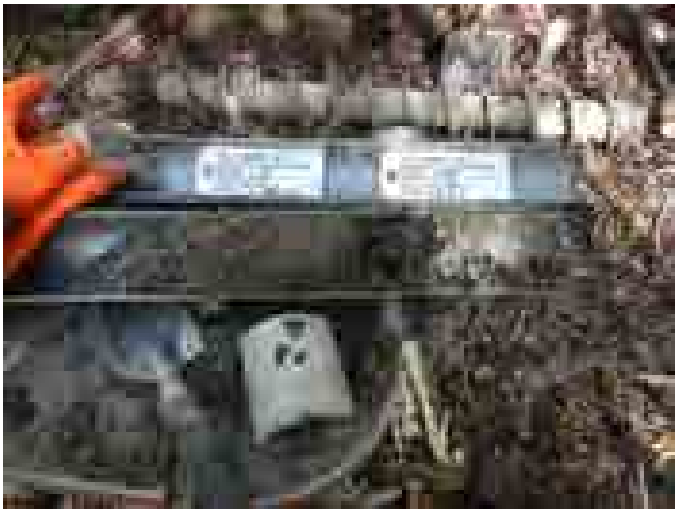
Photograph 18: Drill rig set up at boring 17-04.



Photograph 19: Sample S-1 (grab), boring 17-04, 0.5 feet bgs to 2.0 feet bgs.



Photograph 22: Sample S-10, boring 17-04, 25.0 feet bgs to 26.5 feet bgs.



Photograph 20: Sample S-3a and S-3b, boring 17-04, 5.0 feet bgs to 6.5 feet bgs.



Photograph 23: Sample S-15, boring 17-04, 50.0 feet bgs to 51.5 feet bgs.



Photograph 21: Sample S-5, boring 17-04, 10.0 feet bgs to 11.5 feet bgs.



Photograph 24: Drill rig set up at boring 17-05.



Photograph 25: Sample S-2, boring 17-05, 2.5 feet bgs to 4.0 feet bgs.



Photograph 28: Sample S-9a and S-9b, boring 17-05, 20.0 feet bgs to 21.5 feet bgs.



Photograph 26: Sample S-4, boring 17-05, 7.5 feet bgs to 9.0 feet bgs.



Photograph 29: Sample S-13, boring 17-05, 40 feet bgs to 41.5 feet bgs.



Photograph 27: Sample S-6, boring 17-05, 12.5 feet bgs to 14.0 feet bgs.



Photograph 27: Sample S-16, boring 17-05, 60.0 feet bgs to 61.5 feet bgs.

APPENDIX D

IMPORTANT INFORMATION ABOUT YOUR GEOTECHNICAL / ENVIRONMENTAL REPORT

SHANNON & WILSON, INC.
GEOTECHNICAL AND ENVIRONMENTAL CONSULTANTS

Attachment to and part of Report: 31-1-20006-001R1

Date: June 2017

To: PDC Engineers, Inc.
Attn: Mr. Keith Hanneman, P.E.

Re: Geotechnical Findings Report, GVEA Fuel Storage Facility

IMPORTANT INFORMATION ABOUT YOUR GEOTECHNICAL/ENVIRONMENTAL REPORT

CONSULTING SERVICES ARE PERFORMED FOR SPECIFIC PURPOSES AND FOR SPECIFIC CLIENTS.

Consultants prepare reports to meet the specific needs of specific individuals. A report prepared for a civil engineer may not be adequate for a construction contractor or even another civil engineer. Unless indicated otherwise, your consultant prepared your report expressly for you and expressly for the purposes you indicated. No one other than you should apply this report for its intended purpose without first conferring with the consultant. No party should apply this report for any purpose other than that originally contemplated without first conferring with the consultant.

THE CONSULTANT'S REPORT IS BASED ON PROJECT-SPECIFIC FACTORS.

A geotechnical/environmental report is based on a subsurface exploration plan designed to consider a unique set of project-specific factors. Depending on the project, these may include: the general nature of the structure and property involved; its size and configuration; its historical use and practice; the location of the structure on the site and its orientation; other improvements such as access roads, parking lots, and underground utilities; and the additional risk created by scope-of-service limitations imposed by the client. To help avoid costly problems, ask the consultant to evaluate how any factors that change subsequent to the date of the report may affect the recommendations. Unless your consultant indicates otherwise, your report should not be used: (1) when the nature of the proposed project is changed (for example, if an office building will be erected instead of a parking garage, or if a refrigerated warehouse will be built instead of an unrefrigerated one, or chemicals are discovered on or near the site); (2) when the size, elevation, or configuration of the proposed project is altered; (3) when the location or orientation of the proposed project is modified; (4) when there is a change of ownership; or (5) for application to an adjacent site. Consultants cannot accept responsibility for problems that may occur if they are not consulted after factors which were considered in the development of the report have changed.

SUBSURFACE CONDITIONS CAN CHANGE.

Subsurface conditions may be affected as a result of natural processes or human activity. Because a geotechnical/environmental report is based on conditions that existed at the time of subsurface exploration, construction decisions should not be based on a report whose adequacy may have been affected by time. Ask the consultant to advise if additional tests are desirable before construction starts; for example, groundwater conditions commonly vary seasonally.

Construction operations at or adjacent to the site and natural events such as floods, earthquakes, or groundwater fluctuations may also affect subsurface conditions and, thus, the continuing adequacy of a geotechnical/environmental report. The consultant should be kept apprised of any such events, and should be consulted to determine if additional tests are necessary.

MOST RECOMMENDATIONS ARE PROFESSIONAL JUDGMENTS.

Site exploration and testing identifies actual surface and subsurface conditions only at those points where samples are taken. The data were extrapolated by your consultant, who then applied judgment to render an opinion about overall subsurface conditions. The actual interface between materials may be far more gradual or abrupt than your report indicates. Actual conditions in areas not sampled may differ from those predicted in your report. While nothing can be done to prevent such situations, you and your consultant can work together to help reduce their impacts. Retaining your consultant to observe subsurface construction operations can be particularly beneficial in this respect.

A REPORT'S CONCLUSIONS ARE PRELIMINARY.

The conclusions contained in your consultant's report are preliminary because they must be based on the assumption that conditions revealed through selective exploratory sampling are indicative of actual conditions throughout a site. Actual subsurface conditions can be discerned only during earthwork; therefore, you should retain your consultant to observe actual conditions and to provide conclusions. Only the consultant who prepared the report is fully familiar with the background information needed to determine whether or not the report's recommendations based on those conclusions are valid and whether or not the contractor is abiding by applicable recommendations. The consultant who developed your report cannot assume responsibility or liability for the adequacy of the report's recommendations if another party is retained to observe construction.

THE CONSULTANT'S REPORT IS SUBJECT TO MISINTERPRETATION.

Costly problems can occur when other design professionals develop their plans based on misinterpretation of a geotechnical/environmental report. To help avoid these problems, the consultant should be retained to work with other project design professionals to explain relevant geotechnical, geological, hydrogeological, and environmental findings, and to review the adequacy of their plans and specifications relative to these issues.

BORING LOGS AND/OR MONITORING WELL DATA SHOULD NOT BE SEPARATED FROM THE REPORT.

Final boring logs developed by the consultant are based upon interpretation of field logs (assembled by site personnel), field test results, and laboratory and/or office evaluation of field samples and data. Only final boring logs and data are customarily included in geotechnical/environmental reports. These final logs should not, under any circumstances, be redrawn for inclusion in architectural or other design drawings, because drafters may commit errors or omissions in the transfer process.

To reduce the likelihood of boring log or monitoring well misinterpretation, contractors should be given ready access to the complete geotechnical engineering/environmental report prepared or authorized for their use. If access is provided only to the report prepared for you, you should advise contractors of the report's limitations, assuming that a contractor was not one of the specific persons for whom the report was prepared, and that developing construction cost estimates was not one of the specific purposes for which it was prepared. While a contractor may gain important knowledge from a report prepared for another party, the contractor should discuss the report with your consultant and perform the additional or alternative work believed necessary to obtain the data specifically appropriate for construction cost estimating purposes. Some clients hold the mistaken impression that simply disclaiming responsibility for the accuracy of subsurface information always insulates them from attendant liability. Providing the best available information to contractors helps prevent costly construction problems and the adversarial attitudes that aggravate them to a disproportionate scale.

READ RESPONSIBILITY CLAUSES CLOSELY.

Because geotechnical/environmental engineering is based extensively on judgment and opinion, it is far less exact than other design disciplines. This situation has resulted in wholly unwarranted claims being lodged against consultants. To help prevent this problem, consultants have developed a number of clauses for use in their contracts, reports, and other documents. These responsibility clauses are not exculpatory clauses designed to transfer the consultant's liabilities to other parties; rather, they are definitive clauses that identify where the consultant's responsibilities begin and end. Their use helps all parties involved recognize their individual responsibilities and take appropriate action. Some of these definitive clauses are likely to appear in your report, and you are encouraged to read them closely. Your consultant will be pleased to give full and frank answers to your questions.

The preceding paragraphs are based on information provided by the
ASFE/Association of Engineering Firms Practicing in the Geosciences, Silver Spring, Maryland

Memo to PDC

Reference: GVEA LNG Siting Study

The following are the pertinent issues associated with siting the LNG facilities to service both GVEA and IGU.

1. I is very difficult to provide much detail for an LNG plant layout without the actual design basis for the facility.
2. I know that there is a preference for single containment storage, because the initial cost is less than full containment. However, Full containment offers many advantages, especially in the planning stages. Therefore, we have performed an initial screening for thermal exclusion for an unconfined LNG storage tank failure, which, in our opinion is what is necessary for preliminary siting.
3. We have offered a site plan for single containment, with a high dike that meets the NFPA X-Y rule.
4. However, the actual layout and configuration of the plant LNG transfer facilities, and their design spill determinations, will be required to determine the thermal exclusion and vapor dispersion requirements.
5. Generally we like to locate design spill containment structure as close to the center of the center of the site as possible to provide the most flexibility for thermal exclusion and vapor dispersion.
6. All LNG transfer activities must be identified and the design LNG spills determined in accordance with the published PHMSA FAQ's
    a. Proposed Trucks per day and method of transfer. Unloading only, or filling and unloading?
    b. Proposed rail cars, of what size, per day and method of transfer. Unloading only, or filling and unloading?
    c. Proposed production rates for each customer of the facility.
    d. Is container filling or unloading foreseen?
7. Any kind of crossing of the existing pipeline ROW should be avoided for a variety of reasons, but mainly cost and schedule.
8. Snow management must be determined in any site plan, as well the allowance for the accumulation of ice and snow in the spill impoundment systems.
9. The configuration of any rail facilities should include a single track, and make it as long as necessary, with one security controlled gate. Most of the facilities I am accustomed to in secure facilities have the tack running in a circle, with a minimum of switches. The prime mover for the cars should never pass the transfer area, or the area must be purged a non-classified electrical area before each transit. (At least I think this is the current DOT thinking)
10. The general technical terms of the potential ownership transaction should be included in the basis of design, flow rates, pressures, and temperature. We are concerned with the complexities of contracting between public utility companies, as they may affect the configuration of the facilities.

ALTERNATIVE 1 COST SUMMARY

	BASE BID		
CIVIL WORK (PROVIDED BY GNE)		$	1,309,250
TANK CONSTRUCTION (PROVIDED BY GNE)		$	3,943,000
STRUCTURAL WORK (PROVIDED BY GNE)		$	160,000
MECHANICAL/PIPING WORK (PROVIDED BY GNE)		$	1,120,500
ELECTRICAL WORK (PROVIDED BY GNE)		$	457,000
SITE WORK		$	110,370
SITE MECHANICAL		$	408,153
SITE COMMUNICATIONS		$	50,436
30'0''X40'0" PUMPHOUSE		$	790,141
30'0''X40'0" CONTROL BUILDING		$	603,915
CONSTRUCTION SUBTOTAL		$	8,952,765
DESIGN FEE AND CA	11%	$	984,804.15
PERMITTING/PLAN REVIEWS		$	20,000
SUBTOTAL		$	9,957,569
CONTINGENCY	50%	$	4,978,784.58
SUBTOTAL		$	14,936,354
	ALTERNATES		
1	ACCESS ROAD - H&H TO GVEA YARD	$	356,912
2	TRUCK LOADING FACILITY (PROVIDED BY GNE)	$	1,266,406
3	TRACK MOBILE AND SHELTER	$	877,500
4	GVEA RAIL RACK, PIPING, TRACK AND SWITCHING	$	2,201,750
5	PETRO STAR RAIL RACK, PIPING, TRACK AND SWITCHING	$	1,361,750
6	IGU RAIL SPUR TRACK AND SWITCHING	$	1,087,500
DESIGN FEE AND CA	11%	$	786,699.94
CONTINGENCY	50%	$	3,969,258.77
CONSTRUCTION SUBTOTAL		$	11,907,776
CONSTRUCTION TOTAL INCLUDING ALTERNATES		$	26,844,130

GOLDEN VALLEY ELECTRIC ASSOC. (GVEA)
PETROLEUM TERMINAL FACILITY
3MM GAL TOTAL STORAGE
OPTION #1

6/26/2017

GNE #17013

Revision C

Task	Sub	Task Description	Units	Qty	Unit Cost	Total
1		**Civil Work**				
	1.01	Excavation for Tank Farm: tank foundations, containment dike	CY	16,500	$6.00	$99,000.00
	1.02	Install geomembrane liner under containment area and within tank ringwalls	SF	106,000	$2.25	$238,500.00
	1.03	Liner Bedding, NFS Backfill, Berm and Compaction	CY	19,750	$28.00	$553,000.00
	1.04	Install Subsurface Drainage System. Catch Basins & OWS	LS	1	$75,000.00	$75,000.00
	1.05	Trenching, Bedding, Compaction for POL Pipeline Installation	LF	2,750	$125.00	$343,750.00
		Task 1 Subtotal				**$1,309,250.00**
2		**Tank 1010 and 1020 Construction (1.5MM Gal ea)**				
	2.01	Tank Foundation Ringwalls - 85' Dia x 5' Deep	EA	2	$122,500.00	$245,000.00
	2.02	Tank CP Anode Grid under tanks	EA	2	$61,500.00	$123,000.00
	2.03	Tank Fabricate, Erection 85' Dia. X 40', Fixed Cone Roof	EA	1	$1,575,000.00	$1,575,000.00
	2.04	Tank Fabricate, Erection 85' Dia. X 40' , Internal Floating Roof	EA	1	$1,650,000.00	$1,650,000.00
	2.05	Field Coatings, Hydro, Appurtenances	EA	2	$175,000.00	$350,000.00
		Task 2 Subtotal				**$3,943,000.00**
3		**Structural Work**				
	3.01	Platform/Handrails/Stairs/Pipe Supports/Catwalks within Diked area	LS	1	$95,000.00	$95,000.00
	3.02	Pipe Supports along external pipe routes	LS	1	$65,000.00	$65,000.00
		Task 3 Subtotal				**$160,000.00**
4		**Mechanical / Piping Work**				
	4.01	10" Cargo piping from Pumphouse to Tanks - A/G	LF	550	$95.00	$52,250.00
	4.02	8" Service piping from Pumphouse to Tanks - A/G	LF	550	$85.00	$46,750.00
	4.03	10" Service piping from Pumphouse to Truck Load/Offload - B/G	LF	1,000	$95.00	$95,000.00
	4.04	6" Service piping from Pumphouse to Truck Load/Offload - B/G	LF	2,000	$76.00	$152,000.00
	4.05	10" Cargo piping from Rail Car Offload to Pump House - B/G	LF	1,650	$95.00	$156,750.00
2	4.06	10" Service piping from Pump House to Rail Car Loading- B/G (Petrostar)	LF	1,650	$95.00	$156,750.00
	4.07	4" Service piping from Pump House to GVEA Transfer Bldg - B/G	LF	1,800	$55.00	$99,000.00
	4.08	4" Service piping from Pump House to Peaker Plant - B/G	LF	1,150	$55.00	$63,250.00
	4.09	3" Service to Fuel Forwarding Bldg - A/G	LF	950	$50.00	$47,500.00
	4.10	10" Cargo pipelines from Petrostar to Pump House - A/G	LF	750	$95.00	$71,250.00
	4.11	600 gpm Pumps for Cargo/Service, Valves and Appurtenances	EA	5	$22,500.00	$112,500.00
	4.12	Filter Vessels, Coalescing Elements, Meters, Flow Control Devices	LS	1	$225,000.00	$225,000.00
	4.13	AFFF Piping from Pump to Foam Chambers and 4" Perimeter Line	LF	1,650	$40.00	$66,000.00
	4.14	AFFF Pump, Control Panel, RBFP, Concentrate Tank, Etc	LS	1	$85,000.00	$85,000.00
	4.15	Foam Chambers	EA	2	$2,500.00	$5,000.00
1 1	4.16	Water Line Extension and Hydrants	LS	1	$0.00	$0.00
	4.17	Supplemental Water Storage Tank	EA	1	$0.00	$0.00
		Task 4 Subtotal				**$1,434,000.00**
5		**Rail Car Offloading/Loading Rack**				
1	5.01	Civil Excavation, NFS Fill, Compaction, Rail Extension	LS	1	$0.00	$0.00
	5.02	Six Position Spill Containement, Bottom Unloading Arms, Metering, Valves	LS	1	$225,000.00	$225,000.00
2	5.03	Six Position Rail Car Rack for Loading, Loading Arms, Platforms (Petrostar)	LS	1	$275,000.00	$275,000.00
		Task 5 Subtotal				**$500,000.00**
6		**Truck Loading Rack (TLR)**				
	6.01	Loading Arm, Rest, Connection, 2 Arms	LS	1	$85,000.00	$85,000.00
	6.02	Terminal Management System	LS	1	$105,000.00	$105,000.00
	6.03	Piping, Valves, meter, strainer	LS	1	$84,500.00	$84,500.00
	6.04	Foundation and Heated Lane Containment Slab	LS	1	$65,000.00	$65,000.00
	6.05	Structural Pipe Supports	LS	1	$20,000.00	$20,000.00
1	6.06	Vapor combustion system foundation and equipment	LS	1	$0.00	$0.00
1 1	6.07	Vapor recovery piping	LS	1	$0.00	$0.00
1 1	6.08	Fire water and Foam System	LS	1	$0.00	$0.00
1	6.09	Additive System	LS	1	$0.00	$0.00

GOLDEN VALLEY ELECTRIC ASSOC. (GVEA)
PETROLEUM TERMINAL FACILITY
3MM GAL TOTAL STORAGE
OPTION #1

6/26/2017

GNE #17013

Revision C

Task	Sub	Task Description	Units	Qty	Unit Cost	Total
	6.1	Scully System	LS	1	$75,000.00	$75,000.00
	6.11	Truck Offload Hose, 6" Piping, Valves, Strainer, Connection, etc.	LS	1	$35,000.00	$35,000.00
		Task 6 Subtotal				**$469,500.00**
7		**Electrical Work**				
	7.01	Power within Tank Farm for CP, MOV's, Lighting, Earth Electrode System	LS	1	$215,000.00	$215,000.00
	7.02	EFSO and Fire Alarm System within Tank Farm	LS	1	$32,000.00	$32,000.00
	7.03	Heat Trace for drainage piping	LS	1	$35,000.00	$35,000.00
	7.04	Tank instruments and conduit routing	LS	1	$75,000.00	$75,000.00
	7.05	New indication panel and computer equipment in control room, TMS	LS	1	$60,000.00	$60,000.00
	7.06	Integration of signals to Ovation System, Programming, Commissioning	LS	1	$40,000.00	$40,000.00
		Task 7 Subtotal				**$457,000.00**
					Construction Cost Subtotal Tasks 1-7	**$8,272,750.00**
					Subtotal Minus Alternate Scope Cost	**$7,841,000.00**
					Permitting/Plan Review Fees	**$15,000.00**
					Contingency (10%)	**$784,100.00**
					GRAND TOTAL	**$8,640,100.00**

Assumptions/ Notes:

1. Not currently in Fuel System Scope, listed for reference only.
2. Alternate scope of work to accommodate Petrostar.

ALTERNATIVE 2 COST SUMMARY

	BASE BID		
CIVIL WORK (PROVIDED BY GNE)		$	1,340,500
TANK CONSTRUCTION (PROVIDED BY GNE)		$	3,943,000
STRUCTURAL WORK (PROVIDED BY GNE)		$	160,000
MECHANICAL/PIPING WORK (PROVIDED BY GNE)		$	1,129,675
ELECTRICAL WORK (PROVIDED BY GNE)		$	457,000
SITE WORK		$	110,370
SITE MECHANICAL		$	352,749
SITE COMMUNICATIONS		$	51,662
30'0''X40'0" PUMPHOUSE		$	787,021
30'0''X40'0" CONTROL BUILDING		$	603,915
CONSTRUCTION SUBTOTAL		$	8,935,892
DESIGN FEE AND CA	11%	$	982,948.12
PERMITTING/PLAN REVIEWS		$	20,000
SUBTOTAL		$	9,938,840
CONTINGENCY	50%	$	4,969,420.06
SUBTOTAL		$	14,908,260
	ALTERNATES		
1	ACCESS ROAD - H&H TO GVEA YARD	$	348,852
2	TRUCK LOADING FACILITY (PROVIDED BY GNE)	$	1,216,365
3	TRACK MOBILE AND SHELTER	$	877,500
4	GVEA RAIL RACK, PIPING, TRACK AND SWITCHING	$	2,137,625
5	PETRO STAR RAIL RACK, PIPING, TRACK AND SWITCHING	$	1,297,625
6	IGU RAIL SPUR TRACK AND SWITCHING	$	1,087,500
DESIGN FEE AND CA	11%	$	766,201.34
CONTINGENCY	50%	$	3,865,834.02
CONSTRUCTION SUBTOTAL		$	11,597,502
CONSTRUCTION TOTAL INCLUDING ALTERNATES		$	26,505,762

GOLDEN VALLEY ELECTRIC ASSOC. (GVEA)
PETROLEUM TERMINAL FACILITY
3MM GAL TOTAL STORAGE
OPTION #2

6/26/2017

GNE #17013

Revision C

Task	Sub	Task Description	Units	Qty	Unit Cost	Total
1		**Civil Work**				
	1.01	Excavation for Tank Farm: tank foundations, containment dike	CY	16,500	$6.00	$99,000.00
	1.02	Install geomembrane liner under containment area and within tank ringwalls	SF	106,000	$2.25	$238,500.00
	1.03	Liner Bedding, NFS Backfill, Berm and Compaction	CY	19,750	$28.00	$553,000.00
	1.04	Install Subsurface Drainage System. Catch Basins & OWS	LS	1	$75,000.00	$75,000.00
	1.05	Trenching, Bedding, Compaction for POL Pipeline Installation	LF	3,000	$125.00	$375,000.00
		Task 1 Subtotal				**$1,340,500.00**
2		**Tank 1010 and 1020 Construction (1.5MM Gal ea)**				
	2.01	Tank Foundation Ringwalls - 85' Dia x 5' Deep	EA	2	$122,500.00	$245,000.00
	2.02	Tank CP Anode Grid under tanks	EA	2	$61,500.00	$123,000.00
	2.03	Tank Fabricate, Erection 85' Dia. X 40', Fixed Cone Roof	EA	1	$1,575,000.00	$1,575,000.00
	2.04	Tank Fabricate, Erection 85' Dia. X 40' , Internal Floating Roof	EA	1	$1,650,000.00	$1,650,000.00
	2.05	Field Coatings, Hydro, Appurtenances	EA	2	$175,000.00	$350,000.00
		Task 2 Subtotal				**$3,943,000.00**
3		**Structural Work**				
	3.01	Platform/Handrails/Stairs/Pipe Supports/Catwalks within Diked area	LS	1	$95,000.00	$95,000.00
	3.02	Pipe Supports along external pipe routes	LS	1	$65,000.00	$65,000.00
		Task 3 Subtotal				**$160,000.00**
4		**Mechanical / Piping Work**				
	4.01	10" Cargo piping from Pumphouse to Tanks - A/G	LF	675	$95.00	$64,125.00
	4.02	8" Service piping from Pumphouse to Tanks - A/G	LF	675	$85.00	$57,375.00
	4.03	10" Service piping from Pumphouse to Truck Load/Offload - B/G	LF	150	$95.00	$14,250.00
	4.04	6" Service piping from Pumphouse to Truck Load/Offload - B/G	LF	300	$76.00	$22,800.00
	4.05	10" Cargo piping from Rail Car Offload to Pump House - B/G	LF	975	$95.00	$92,625.00
2	4.06	10" Service piping from Pump House to Rail Car Loading- B/G (Petrostar)	LF	975	$95.00	$92,625.00
	4.07	4" Service piping from Pump House to GVEA Transfer Bldg - B/G	LF	2,550	$55.00	$140,250.00
	4.08	4" Service piping from Pump House to Peaker Plant - B/G	LF	975	$55.00	$53,625.00
	4.09	3" Service to Fuel Forwarding Bldg - A/G	LF	1,700	$50.00	$85,000.00
	4.10	10" Cargo pipelines from Petrostar to Pump House - A/G	LF	2,050	$95.00	$194,750.00
	4.11	600 gpm Pumps for Cargo/Service, Valves and Appurtenances	EA	5	$22,500.00	$112,500.00
	4.12	Filter Vessels, Coalescing Elements, Meters, Flow Control Devices	LS	1	$225,000.00	$225,000.00
	4.13	AFFF Piping from Pump to Foam Chambers and 4" Perimeter Line	LF	1,750	$40.00	$70,000.00
	4.14	AFFF Pump, Control Panel, RBFP, Concentrate Tank, Etc	LS	1	$85,000.00	$85,000.00
	4.15	Foam Chambers	EA	2	$2,500.00	$5,000.00
1 1	4.16	Water Line Extension and Hydrants	LS	1	$0.00	$0.00
	4.17	Supplemental Water Storage Tank	EA	1	$0.00	$0.00
		Task 4 Subtotal				**$1,314,925.00**
5		**Rail Car Offloading/Loading Rack**				
1	5.01	Civil Excavation, NFS Fill, Compaction, Rail Extension	LS	1	$0.00	$0.00
	5.02	Six Position Spill Containement, Bottom Unloading Arms, Metering, Valves	LS	1	$225,000.00	$225,000.00
2	5.03	Six Position Rail Car Rack for Loading, Loading Arms, Platforms (Petrostar)	LS	1	$275,000.00	$275,000.00
		Task 5 Subtotal				**$500,000.00**
6		**Truck Loading Rack (TLR)**				
	6.01	Loading Arm, Rest, Connection, 2 Arms	LS	1	$85,000.00	$85,000.00
	6.02	Terminal Management System	LS	1	$105,000.00	$105,000.00
	6.03	Piping, Valves, meter, strainer	LS	1	$84,500.00	$84,500.00
	6.04	Foundation and Heated Lane Containment Slab	LS	1	$65,000.00	$65,000.00
	6.05	Structural Pipe Supports	LS	1	$20,000.00	$20,000.00
1	6.06	Vapor combustion system foundation and equipment	LS	1	$0.00	$0.00
1 1	6.07	Vapor recovery piping	LS	1	$0.00	$0.00
1 1	6.08	Fire water and Foam System	LS	1	$0.00	$0.00
1	6.09	Additive System	LS	1	$0.00	$0.00

GOLDEN VALLEY ELECTRIC ASSOC. (GVEA)
PETROLEUM TERMINAL FACILITY
3MM GAL TOTAL STORAGE
OPTION #2

6/26/2017

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Revision C

Task	Sub	Task Description	Units	Qty	Unit Cost	Total
	6.1	Scully System	LS	1	$75,000.00	$75,000.00
	6.11	Truck Offload Hose, 6" Piping, Valves, Strainer, Connection, etc.	LS	1	$35,000.00	$35,000.00
		Task 6 Subtotal				**$469,500.00**
7		**Electrical Work**				
	7.01	Power within Tank Farm for CP, MOV's, Lighting, Earth Electrode System	LS	1	$215,000.00	$215,000.00
	7.02	EFSO and Fire Alarm System within Tank Farm	LS	1	$32,000.00	$32,000.00
	7.03	Heat Trace for drainage piping	LS	1	$35,000.00	$35,000.00
	7.04	Tank instruments and conduit routing	LS	1	$75,000.00	$75,000.00
	7.05	New indication panel and computer equipment in control room, TMS	LS	1	$60,000.00	$60,000.00
	7.06	Integration of signals to Ovation System, Programming, Commissioning	LS	1	$40,000.00	$40,000.00
		Task 7 Subtotal				**$457,000.00**
					Construction Cost Subtotal Tasks 1-7	**$8,184,925.00**
					Subtotal Minus Alternate Scope Cost	**$7,817,300.00**
					Permitting/Plan Review Fees	**$15,000.00**
					Contingency (10%)	**$781,730.00**
					GRAND TOTAL	**$8,614,030.00**

Assumptions/ Notes:

1. Not currently in Fuel System Scope, listed for reference only.
2. Alternate scope of work to accommodate Petrostar.

ALTERNATIVE 3 COST SUMMARY

	BASE BID		
CIVIL WORK (PROVIDED BY GNE)		$	1,340,500
TANK CONSTRUCTION (PROVIDED BY GNE)		$	3,943,000
STRUCTURAL WORK (PROVIDED BY GNE)		$	160,000
MECHANICAL/PIPING WORK (PROVIDED BY GNE)		$	1,457,550
ELECTRICAL WORK (PROVIDED BY GNE)		$	457,000
SITE WORK		$	110,370
SITE MECHANICAL		$	439,507
SITE COMMUNICATIONS		$	50,123
30'0''X40'0" PUMPHOUSE		$	787,021
30'0''X40'0" CONTROL BUILDING		$	603,915
CONSTRUCTION SUBTOTAL		$	9,348,986
DESIGN FEE AND CA	11%	$	1,028,388.46
PERMITTING/PLAN REVIEWS		$	20,000
SUBTOTAL		$	10,397,374
CONTINGENCY	50%	$	5,198,687.23
SUBTOTAL		$	15,596,062
	ALTERNATES		
1	ACCESS ROAD - H&H TO GVEA YARD	$	348,852
2	TRUCK LOADING FACILITY (PROVIDED BY GNE)	$	1,356,132
3	TRACK MOBILE AND SHELTER	$	877,500
4	GVEA RAIL RACK, PIPING, TRACK AND SWITCHING	$	2,121,000
5	PETRO STAR RAIL RACK, PIPING, TRACK AND SWITCHING	$	1,281,000
6	IGU RAIL SPUR TRACK AND SWITCHING	$	1,087,500
DESIGN FEE AND CA	11%	$	777,918.20
CONTINGENCY	50%	$	3,924,950.90
CONSTRUCTION SUBTOTAL		$	11,774,853
CONSTRUCTION TOTAL INCLUDING ALTERNATES		$	27,370,914

GOLDEN VALLEY ELECTRIC ASSOC. (GVEA)
PETROLEUM TERMINAL FACILITY
3MM GAL TOTAL STORAGE
OPTION #3

6/26/2017

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Revision C

Task	Sub	Task Description	Units	Qty	Unit Cost	Total
1		**Civil Work**				
	1.01	Excavation for Tank Farm: tank foundations, containment dike	CY	16,500	$6.00	$99,000.00
	1.02	Install geomembrane liner under containment area and within tank ringwalls	SF	106,000	$2.25	$238,500.00
	1.03	Liner Bedding, NFS Backfill, Berm and Compaction	CY	19,750	$28.00	$553,000.00
	1.04	Install Subsurface Drainage System. Catch Basins & OWS	LS	1	$75,000.00	$75,000.00
	1.05	Trenching, Bedding, Compaction for POL Pipeline Installation	LF	3,000	$125.00	$375,000.00
		Task 1 Subtotal				**$1,340,500.00**
2		**Tank 1010 and 1020 Construction (1.5MM Gal ea)**				
	2.01	Tank Foundation Ringwalls - 85' Dia x 5' Deep	EA	2	$122,500.00	$245,000.00
	2.02	Tank CP Anode Grid under tanks	EA	2	$61,500.00	$123,000.00
	2.03	Tank Fabricate, Erection 85' Dia. X 40', Fixed Cone Roof	EA	1	$1,575,000.00	$1,575,000.00
	2.04	Tank Fabricate, Erection 85' Dia. X 40' , Internal Floating Roof	EA	1	$1,650,000.00	$1,650,000.00
	2.05	Field Coatings, Hydro, Appurtenances	EA	2	$175,000.00	$350,000.00
		Task 2 Subtotal				**$3,943,000.00**
3		**Structural Work**				
	3.01	Platform/Handrails/Stairs/Pipe Supports/Catwalks within Diked area	LS	1	$95,000.00	$95,000.00
	3.02	Pipe Supports along external pipe routes	LS	1	$65,000.00	$65,000.00
		Task 3 Subtotal				**$160,000.00**
4		**Mechanical / Piping Work**				
	4.01	10" Cargo piping from Pumphouse to Tanks - A/G	LF	1,500	$95.00	$142,500.00
	4.02	8" Service piping from Pumphouse to Tanks - A/G	LF	1,500	$85.00	$127,500.00
	4.03	10" Service piping from Pumphouse to Truck Load/Offload - B/G	LF	150	$95.00	$14,250.00
	4.04	6" Service piping from Pumphouse to Truck Load/Offload - B/G	LF	300	$76.00	$22,800.00
	4.05	10" Cargo piping from Rail Car Offload to Pump House - B/G	LF	800	$95.00	$76,000.00
2	4.06	10" Service piping from Pump House to Rail Car Loading- B/G (Petrostar)	LF	800	$95.00	$76,000.00
	4.07	4" Service piping from Pump House to GVEA Transfer Bldg - B/G	LF	2,750	$55.00	$151,250.00
	4.08	4" Service piping from Pump House to Peaker Plant - B/G	LF	1,150	$55.00	$63,250.00
	4.09	3" Service to Fuel Forwarding Bldg - A/G	LF	1,900	$50.00	$95,000.00
	4.10	10" Cargo pipelines from Petrostar to Pump House - A/G	LF	3,300	$95.00	$313,500.00
	4.11	600 gpm Pumps for Cargo/Service, Valves and Appurtenances	EA	5	$22,500.00	$112,500.00
	4.12	Filter Vessels, Coalescing Elements, Meters, Flow Control Devices	LS	1	$225,000.00	$225,000.00
	4.13	AFFF Piping from Pump to Foam Chambers and 4" Perimeter Line	LF	2,500	$40.00	$100,000.00
	4.14	AFFF Pump, Control Panel, RBFP, Concentrate Tank, Etc	LS	1	$85,000.00	$85,000.00
	4.15	Foam Chambers	EA	2	$2,500.00	$5,000.00
1	4.16	Water Line Extension and Hydrants	LS	1	$0.00	$0.00
1	4.17	Supplemental Water Storage Tank	EA	1	$0.00	$0.00
		Task 4 Subtotal				**$1,609,550.00**
5		**Rail Car Offloading/Loading Rack**				
1	5.01	Civil Excavation, NFS Fill, Compaction, Rail Extension	LS	1	$0.00	$0.00
	5.02	Six Position Spill Containement, Bottom Unloading Arms, Metering, Valves	LS	1	$225,000.00	$225,000.00
2	5.03	Six Position Rail Car Rack for Loading, Loading Arms, Platforms (Petrostar)	LS	1	$275,000.00	$275,000.00
		Task 5 Subtotal				**$500,000.00**
6		**Truck Loading Rack (TLR)**				
	6.01	Loading Arm, Rest, Connection, 2 Arms	LS	1	$85,000.00	$85,000.00
	6.02	Terminal Management System	LS	1	$105,000.00	$105,000.00
	6.03	Piping, Valves, meter, strainer	LS	1	$84,500.00	$84,500.00
	6.04	Foundation and Heated Lane Containment Slab	LS	1	$65,000.00	$65,000.00
	6.05	Structural Pipe Supports	LS	1	$20,000.00	$20,000.00
1	6.06	Vapor combustion system foundation and equipment	LS	1	$0.00	$0.00
1	6.07	Vapor recovery piping	LS	1	$0.00	$0.00
1	6.08	Fire water and Foam System	LS	1	$0.00	$0.00
1	6.09	Additive System	LS	1	$0.00	$0.00

GOLDEN VALLEY ELECTRIC ASSOC. (GVEA)
PETROLEUM TERMINAL FACILITY
3MM GAL TOTAL STORAGE
OPTION #3

6/26/2017

GNE #17013

Revision C

Task	Sub	Task Description	Units	Qty	Unit Cost	Total
	6.1	Scully System	LS	1	$75,000.00	$75,000.00
	6.11	Truck Offload Hose, 6" Piping, Valves, Strainer, Connection, etc.	LS	1	$35,000.00	$35,000.00
		Task 6 Subtotal				**$469,500.00**
7		**Electrical Work**				
	7.01	Power within Tank Farm for CP, MOV's, Lighting, Earth Electrode System	LS	1	$215,000.00	$215,000.00
	7.02	EFSO and Fire Alarm System within Tank Farm	LS	1	$32,000.00	$32,000.00
	7.03	Heat Trace for drainage piping	LS	1	$35,000.00	$35,000.00
	7.04	Tank instruments and conduit routing	LS	1	$75,000.00	$75,000.00
	7.05	New indication panel and computer equipment in control room, TMS	LS	1	$60,000.00	$60,000.00
	7.06	Integration of signals to Ovation System, Programming, Commissioning	LS	1	$40,000.00	$40,000.00
		Task 7 Subtotal				**$457,000.00**
					Construction Cost Subtotal Tasks 1-7	**$8,479,550.00**
					Subtotal Minus Alternate Scope Cost	**$8,128,550.00**
					Permitting/Plan Review Fees	**$15,000.00**
					Contingency (10%)	**$812,855.00**
					GRAND TOTAL	**$8,956,405.00**

Assumptions/ Notes:

1. Not currently in Fuel System Scope, listed for reference only.
2. Alternate scope of work to accommodate Petrostar.

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Attachment 3
Leidos Strategic Fuel Evaluation

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BACT Analysis of Zehnder and North Pole Power Plants: Use of Low Sulfur Fuels

Delma Bratvold
Energy Analyst
Leidos Engineering
July 2017

The North Pole Power Plant (NPPP) has two GE Frame 7 combustion turbines (GT1 and GT2) and the Zehnder Power Plant has two GE Frame 5 combustion turbines. In 2016, high sulfur diesel comprised 85% of the fuel burned in the North Pole Plant and 98% of the fuel burned in the Zehnder Plant. However, the turbines at both of these plants are capable of burning 100% ultra low sulfur diesel (ULSD). An analysis of the capital investment required for burning 100% ULSD at both the North Pole Power Plant and the Zehnder Power Plant is described below.

1 Needed ULSD Storage Volume

Two scenarios of ULSD storage volume are considered. In the first scenario, the needed storage volume is based on maximum permitted operation of both the NPPP and the Zehnder Plant. In the second scenario, storage volume is based on historic maximum fuel energy use at these plants.

ULSD is produced in Alaska at two refineries: one is 350 miles away in Valdez; the other is 530 miles away in Kenai. Both of these refineries have, or are in the process of establishing bulk storage at marine terminals in Anchorage, which is 370 miles from away. Both refineries are likely to transport bulk ULSD to North Pole through their Anchorage terminals to allow rail transport, which is not directly available from the refineries themselves. The quantities of ULSD required for NPPP and Zehnder operation are preferentially transported by rail rather than truck due to: difficult winter road conditions; periodic regional shortages of truck drivers; and economies of scale in transport by 30,000 gallon railcars versus tank trucks with a maximum load of around 9,000 gallons.

With no delays, rail transport from Anchorage to North Pole is 3 days one way, and 7 days round trip including fuel loading and off-loading. Shipments are assumed to arrive twice a week, and at any one time, half the railcars will be headed towards or in North Pole and the other half will be headed towards or in Anchorage. This requires an operational storage volume equivalent to 3 ½ days of fuel. The longer transport chain for ULSD from Anchorage compared to high sulfur diesel produced in North Pole poses additional delivery risk which is mitigated with North Pole fuel storage capacity that allows for reasonable delivery delays. The Alaska Railroad has stated that in the event of destruction of one of the higher rail bridges between Anchorage and North Pole (e.g., such as due to an avalanche), bridge replacement may take up to 4 days. Thus, fuel storage capacity should be equivalent to a total of 7 ½ days of fuel (i.e., 3 ½ days for operational fuel plus 4 additional days for reasonable delivery delays).

Under the first scenario, with maximum permitted use of NPPP and Zehnder Power Plant, maximum permitted levels are calculated based on the number of days for round-trip fuel deliveries, the potential over-lap in their days of operation, and maximum daily fuel burn rates. The emissions permit for the Zehnder Power Plant allows operation of both GT1 and GT2 365 days per year. The emission permit for NPPP GT2 allows a maximum of 7,992 hours per year by, equivalent to 333 days per year. Maximum use of the NPPP GT1 is limited based on a shared NOx emissions permit, from which maximum operation is

estimated to be 3,794 hours,[1] which is equivalent to 158 days per year. Based on the maximum permitted usage of the NPPP and Zehnder Plants, ULSD storage needs to be adequate for simultaneous operation of both NPPP units and both Zehnder units on a continuous basis for months at a time.

NPPP GT1 and GT2 each burn 672 MMBtu per hour, equivalent to a combined 32,256 MMBtu per day. Zehnder GT1 and GT2 each burn 268 MMBtu per hour, equivalent to a combined 12,864 MMBtu per day. Assuming use of ULSD #1 (winter fuel) with a lower heating value of 124,000 Btu/gallon, the combined maximum daily use of ULSD at both of these plants is 363,871 gallons. Multiplied by 7 ½ days (i.e., 3 ½ days regular delivery plus 4 days delay), this daily use volume corresponds to 2.73 million gallons of new storage capacity.

Under the second scenario, storage volume is based on the maximum 3-day fuel energy use at NPPP and Zehnder over the last decade. A 3-day maximum is used because this duration is approximately equal to the one-way delivery period. The maximum is used (rather than the average) to assure adequate fuel supply during winter cold spells. The 3-day maximum since January 2007 occurred in April 2009, when 62,751 MMBtu were consumed at NPP and Zehnder, equivalent to 506,057 gallons of ULSD #1. The average daily use rate during the 3-day maximum is applied to 7 ½ days storage, yielding 1.27million gallons of new storage capacity.

2 Storage and Transport Component Costs

GVEA owns a site in North Pole that is conducive for construction of shared bulk fuel storage for the NPPP and Zehnder Plant. The complete fuel transport chain from Anchorage is assumed to include rail delivery to bulk storage in North Pole with new rail siding and offloading equipment; new rail tankcars; new bulk storage including pipeline transport of ULSD to NPPP GT1 and GT2; and truck loading and transport of ULSD from North Pole storage to the Zehnder Plant in Fairbanks (approximately 10 miles each way).[2] Estimated costs of these components are shown in the table below.

Table 1. Fuel Storage and Transport Capital Costs under Permitted Maximum Use Scenario and Historic Maximum Use Scenario.

Capital Cost Elements	**Permitted Maximum Use**	**Historic Maximum Use**
Rail siding, rail/truck loading/offloading	$4,500,000	$4,500,000
Rail tank cars *(30,000 gallons, $135,000 each)*	$11,475,000	$5,400,000
Storage construction	$14,300,000	$11,000,000
Tanker truck *(1 truck @ 9,000 gallons)*	$150,000	$150,000
TOTAL	**$30,425,000**	**$21,050,000**

[1] The NPPP GT1 annual use estimate is calculated from the NOx emissions permit for 1600 tons per year for combined emissions from NPPP GT1 and the NPEP GT3, the later of which only burns low sulfur fuels. If NPEP GT3 (the more efficient unit) is run 24/7, assuming a burn rate of 455 MMBtu/hr and NOx emission rate of 0.24 lb/MMBtu, 478 tons NOx will be emitted annually from GT3, leaving 1,122 tons that may be emitted from GT1. Assuming a NOx emission rate of 0.88 lb/MMBtu for GE Frame 7 turbines, the GT1 may burn 2,549,327 MMBtu per year, which at a burn rate of 672 MMBtu/hr corresponds to 3,794 hours.

[2] The Zehnder plant already has 100,000 gallons of storage on site, compared to the estimated 103,742 gallons of ULSD that would be burned daily at this site when operating at maximum capacity.

Storage construction cost and rail siding, rail/truck loading/offloading costs shown above are based on a July 2017 estimate developed by PDC Engineers for a 3 million-gallon storage facility in North Pole, AK.[3] The PDC estimate was adjusted with volume-proportionate reductions in tank construction, civil, and structural costs to represent 2.73 and 1.27 million gallons for the "Permitted Maximum Use" and "Historic Maximum Use" scenarios, respectively. Components in the estimate that are not applicable for the scope of NPPP and Zehnder fuel storage, rail offloading, and truck loading were removed. Other components (i.e., electrical, piping, mechanical, etc.) are assumed to not change significantly over this size range. Rail tank car costs are based on a June 2017 quote from Greenbrier, Inc., and does not include the cost of car delivery from the Lower 48 to Alaska. Tanker truck cost is based on online listings for truck sales.

[3] This cost estimate was developed for consideration of storage to supply all GVEA liquid fuel power plants during potential strategic events. No strategic storage investment decision has been made.

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Attachment 4
January 2017 through October 2018 Fuel Prices

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GVEA Fuel Pricing per Gallon

			Average	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-18	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18
North Pole	LSR Naphtha	PSI Base Price		-	$1.329	$1.071	$1.083	$1.022	$1.004	$0.999	$1.055	$1.056	$1.200	$1.418	$1.561	$1.584	$1.540	$1.494	$1.516	$1.682	$1.641	$1.713	$1.716	$1.779	$1.785
		PSI & Federal surcharges *		-	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
		Total $/Gallon	**$1.396**	**-**	**$1.332**	**$1.074**	**$1.086**	**$1.025**	**$1.007**	**$1.002**	**$1.058**	**$1.059**	**$1.203**	**$1.421**	**$1.564**	**$1.587**	**$1.543**	**$1.497**	**$1.519**	**$1.685**	**$1.644**	**$1.716**	**$1.719**	**$1.782**	**$1.788**
	DF2+10	PSI Base Price		-	-	-	-	$1.625	$1.576	$1.621	$1.708	-	-	-	-	-	-	-	-	$2.150	$2.286	$2.395	$2.400	$2.408	-
		PSI & Federal surcharges *		-	-	-	-	$0.003	$0.003	$0.003	$0.003	-	-	-	-	-	-	-	-	$0.003	$0.003	$0.003	$0.003	$0.003	-
		PSI Ops Surcharge		-	-	-	-	$0.05	$0.05	$0.05	$0.05	-	-	-	-	-	-	-	-	$0.05	$0.05	$0.05	$0.05	$0.05	-
		Delivery Charge		-	-	-	-	$0.020	$0.020	$0.020	$0.020	-	-	-	-	-	-	-	-	$0.020	$0.020	$0.020	$0.020	$0.020	-
		Delivery Fuel Surcharge %		-	-	-	-	20.5%	20.5%	20.5%	19.0%	-	-	-	-	-	-	-	-	29.0%	27.0%	27.0%	23.5%	26.0%	-
		Delivery Fuel Surchage (%*Delivery)		-	-	-	-	$0.004	$0.004	$0.004	$0.004	-	-	-	-	-	-	-	-	$0.006	$0.005	$0.005	$0.005	$0.005	-
		Total $/Gallon	**$2.097**	**-**	**-**	**-**	**-**	**$1.702**	**$1.653**	**$1.699**	**$1.785**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**$2.229**	**$2.364**	**$2.474**	**$2.478**	**$2.486**	**-**
	DF2-15	PSI Base Price		$1.750	$1.797	$1.712	$1.732	-	-	-	-	$1.874	$1.911	$2.040	$2.021	$2.174	$2.204	$2.188	$2.175	-	-	-	-	-	$2.499
		PSI & Federal surcharges *		$0.003	$0.003	$0.003	$0.003	-	-	-	-	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	-	-	-	-	-	$0.003
		PSI Ops Surcharge		$0.04	$0.05	$0.05	$0.05	-	-	-	-	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	-	-	-	-	-	$0.05
		Truck Delivery		$0.020	$0.020	$0.020	$0.020	-	-	-	-	$0.020	$0.020	$0.020	$0.020	$0.020	$0.020	$0.020	$0.020	-	-	-	-	-	$0.020
		Delivery Fuel Surcharge %		18.5%	20.5%	20.5%	20.5%	-	-	-	-	23.0%	23.0%	23.0%	23.0%	24.0%	26.0%	26.0%	26.0%	-	-	-	-	-	26.0%
		Delivery Fuel Surchate (%*Delivery)		$0.004	$0.004	$0.004	$0.004	-	-	-	-	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	-	-	-	-	-	$0.005
		Total $/Gallon	**$2.083**	**$1.817**	**$1.874**	**$1.789**	**$1.809**	**-**	**-**	**-**	**-**	**$1.951**	**$1.989**	**$2.117**	**$2.099**	**$2.251**	**$2.282**	**$2.266**	**$2.253**	**-**	**-**	**-**	**-**	**-**	**$2.577**
	ULSD	PSI Base Price		$1.963	$1.904	$1.805	$1.852	$1.806	$1.703	$1.622	$1.797	$2.074	$2.107	$2.159	$2.038	$2.129	$2.083	$2.083	$2.309	$2.417	$3.129	$2.301	$2.225	$2.308	$2.406
		PSI & Federal surcharges *		$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
		PSI Delivery Charge		$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155
		PSI Fuel Surcharge %		16.5%	17.5%	17.5%	16.5%	16.5%	16.5%	16.5%	14.5%	16.5%	16.5%	19.5%	20.0%	19.0%	20.0%	20.0%	20.0%	21.5%	22.5%	22.5%	22.0%	21.0%	22.0%
		PSI Fuel Surcharge (%*Delivery)		$0.026	$0.027	$0.027	$0.026	$0.026	$0.026	$0.026	$0.022	$0.026	$0.026	$0.030	$0.031	$0.029	$0.031	$0.031	$0.031	$0.033	$0.035	$0.035	$0.034	$0.033	$0.034
		PSI Truck Freight %		15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
		PSI Truck Freight (%*Delivery+Surchage)		$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028
		Truck Delivery		$0.133	$0.133	$0.133	$0.133	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165
		Delivery Fuel Surcharge %		18.5%	20.5%	20.5%	20.5%	20.5%	20.5%	20.5%	19.0%	23.0%	23.0%	23.0%	23.0%	24.0%	26.0%	26.0%	26.0%	29.0%	27.0%	27.0%	23.5%	26.0%	26.0%
		Delivery Fuel Surchage (%*Delivery)		$0.025	$0.027	$0.027	$0.027	$0.034	$0.034	$0.034	$0.031	$0.038	$0.038	$0.038	$0.038	$0.040	$0.043	$0.043	$0.043	$0.048	$0.045	$0.045	$0.039	$0.043	$0.043
		Total $/Gallon	**$2.512**	**$2.331**	**$2.277**	**$2.178**	**$2.223**	**$2.216**	**$2.112**	**$2.032**	**$2.200**	**$2.487**	**$2.521**	**$2.578**	**$2.458**	**$2.549**	**$2.508**	**$2.508**	**$2.734**	**$2.849**	**$3.560**	**$2.732**	**$2.649**	**$2.735**	**$2.834**
Zehnder	DF2+10	PSI Base Price		-	-	-	-	$1.625	$1.576	$1.621	$1.708	-	-	-	-	-	-	-	-	$2.150	$2.286	$2.395	$2.400	$2.408	-
		PSI & Federal surcharges *		-	-	-	-	$0.003	$0.003	$0.003	$0.003	-	-	-	-	-	-	-	-	$0.003	$0.003	$0.003	$0.003	$0.003	-
		PSI Ops Surcharge		-	-	-	-	$0.05	$0.05	$0.05	$0.05	-	-	-	-	-	-	-	-	$0.05	$0.05	$0.05	$0.05	$0.05	-
		Delivery Charge		-	-	-	-	$0.030	$0.030	$0.030	$0.030	-	-	-	-	-	-	-	-	$0.030	$0.030	$0.030	$0.030	$0.030	-
		Delivery Fuel Surcharge %		-	-	-	-	20.5%	20.5%	20.5%	19.0%	-	-	-	-	-	-	-	-	29.0%	27.0%	27.0%	23.5%	26.0%	-
		Delivery Fuel Surchage (%*Delivery)		-	-	-	-	$0.006	$0.006	$0.006	$0.006	-	-	-	-	-	-	-	-	$0.009	$0.008	$0.008	$0.007	$0.008	-
		Total $/Gallon	**$2.109**	**-**	**-**	**-**	**-**	**$1.714**	**$1.665**	**$1.711**	**$1.797**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**$2.242**	**$2.377**	**$2.487**	**$2.490**	**$2.499**	**-**
	DF2-15	PSI Base Price		$1.750	$1.797	$1.712	$1.732	-	-	-	-	$1.874	$1.911	$2.040	$2.021	$2.174	$2.204	$2.188	$2.175	-	-	-	-	-	$2.499
		PSI & Federal surcharges *		$0.003	$0.003	$0.003	$0.003	-	-	-	-	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	-	-	-	-	-	$0.003
		PSI Ops Surcharge		$0.04	$0.05	$0.05	$0.05	-	-	-	-	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	-	-	-	-	-	$0.05
		Truck Delivery		$0.025	$0.025	$0.025	$0.025	-	-	-	-	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	-	-	-	-	-	$0.030
		Delivery Fuel Surcharge %		18.5%	20.5%	20.5%	20.5%	-	-	-	-	23.0%	23.0%	23.0%	23.0%	24.0%	26.0%	26.0%	26.0%	-	-	-	-	-	26.0%
		Delivery Fuel Surchate (%*Delivery)		$0.005	$0.005	$0.005	$0.005	-	-	-	-	$0.007	$0.007	$0.007	$0.007	$0.007	$0.008	$0.008	$0.008	-	-	-	-	-	$0.008
		Total $/Gallon	**$2.093**	**$1.823**	**$1.880**	**$1.795**	**$1.815**	**-**	**-**	**-**	**-**	**$1.964**	**$2.001**	**$2.129**	**$2.111**	**$2.264**	**$2.294**	**$2.279**	**$2.266**	**-**	**-**	**-**	**-**	**-**	**$2.590**
	ULSD	PSI Base Price		$1.963	$1.904	$1.805	$1.852	$1.806	$1.703	$1.622	$1.797	$2.074	$2.107	$2.159	$2.038	$2.129	$2.083	$2.083	$2.309	$2.417	$3.129	$2.301	$2.225	$2.308	$2.406
		PSI & Federal surcharges *		$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.006	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
		PSI Delivery Charge		$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155
		PSI Fuel Surcharge %		16.5%	17.5%	17.5%	16.5%	16.5%	16.5%	16.5%	14.5%	16.5%	16.5%	19.5%	20.0%	19.0%	20.0%	20.0%	20.0%	21.5%	22.5%	22.5%	22.0%	21.0%	22.0%
		PSI Fuel Surcharge (%*Delivery)		$0.026	$0.027	$0.027	$0.026	$0.026	$0.026	$0.026	$0.022	$0.026	$0.026	$0.030	$0.031	$0.029	$0.031	$0.031	$0.031	$0.033	$0.035	$0.035	$0.034	$0.033	$0.034
		PSI Truck Freight %		15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
		PSI Truck Freight (%*Delivery+Surchage)		$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028
		Truck Delivery		$0.025	$0.025	$0.025	$0.025	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030
		Delivery Fuel Surcharge %		18.5%	20.5%	20.5%	20.5%	20.5%	20.5%	20.5%	19.0%	23.0%	23.0%	23.0%	23.0%	24.0%	26.0%	26.0%	26.0%	29.0%	27.0%	27.0%	23.5%	26.0%	26.0%
		Delivery Fuel Surchage (%*Delivery)		$0.005	$0.005	$0.005	$0.005	$0.006	$0.006	$0.006	$0.006	$0.007	$0.007	$0.007	$0.007	$0.007	$0.008	$0.008	$0.008	$0.009	$0.008	$0.008	$0.007	$0.008	$0.008
		Total $/Gallon	**$2.352**	**$2.203**	**$2.147**	**$2.048**	**$2.093**	**$2.053**	**$1.950**	**$1.869**	**$2.040**	**$2.324**	**$2.355**	**$2.412**	**$2.292**	**$2.382**	**$2.338**	**$2.338**	**$2.564**	**$2.675**	**$3.389**	**$2.560**	**$2.482**	**$2.564**	**$2.664**

Notes: During the time frame shown here, 5,755,774 gallons of DF2+10 and 8,829,573 gallons of DF2-15 were consumed by EU ID's 1 and 2 at the North Pole Plant, giving a weighted average cost differential between No. 2 HSD and ULSD of $0.424 per gallon.

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Alternative BACT
November 2018

Attachment 5a
Updated Cost Effectiveness Tables North Pole

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Table 5-1. Summary of Available SO_2 Emission Control Technology

Emission Unit		Available Emission Control Technology
1, 2	Simple Cycle Gas Turbine	ULSD
		Low Sulfur Fuel
		No. 1 HSD
		Good Combustion Practices
5, 6	Combined Cycle Gas Turbine	ULSD
		LSR/Naphtha
		Limited Operation
		Good Combustion Practices
7	Emergency Generator Engine	ULSD
		Low Sulfur Fuel
		Limited Operation
		Good Combustion Practices
11, 12	Propane-Fired Boiler	Low Sulfur Fuel
		Good Combustion Practices

Table 5-2. Summary of Technically Feasible SO_2 Emission Control Technology

Emission Unit		Technically Feasible Control Technology
1, 2	Simple Cycle Gas Turbine	ULSD
		Low Sulfur Fuel
		No. 1 HSD
		Good Combustion Practices
5, 6	Combined Cycle Gas Turbine	ULSD
		Good Combustion Practices and LSR/Naphtha
7	Emergency Generator Engine	ULSD
		Low Sulfur Fuel
		Limited Operation
		Good Combustion Practices
11, 12	Propane-Fired Boiler	Low Sulfur Fuel
		Good Combustion Practices

Table 5-3. Ranking of Technically Feasible SO_2 Emission Control Technology

Emission Unit		Emission Control Technology	Control Efficiency (pct.)	SO_2 Emissions (tpy)	SO_2 Emissions Reduction (tpy)
1	Simple Cycle Turbine	ULSD (0.0015 wt. pct. S)	99.7	4.5	1,481.9
		Low Sulfur Fuel (0.05 wt. pct. S)	90.0	148.6	1,337.8
		No. 1 HSD (0.100 wt. pct. S)	80.0	297.3	1,189.1
		Good Combustion Practices (0.50 wt. pct. S) (existing)	0	1,486.4	0
2	Simple Cycle Turbine	Limited Operation + ULSD (0.0015 wt. pct. S)	99.7	4.1	1,352.0
		Limited Operation + Low Sulfur Fuel (0.05 wt. pct. S)	90.0	135.6	1,220.5
		Limited Operations + No. 1 HSD (0.100 wt. pct. S)	80.0	271.2	1,084.9
		Good Combustion Practices (0.50 wt. pct. S) (existing)	0	1,356.1	0
5, 6	Combined Cycle Gas Turbines (per turbine)	ULSD (0.0015 wt. pct. S)	70.0	3.0	7.1
		LSR/Naphtha (0.0050 wt. pct. S) + Good Combustion Practices (existing)	0	10.1	0.0
7	Emergency Generator Engine	ULSD (0.0015 wt. pct. S) + Limited Operation	98.5	0.00015	0.0099
		Low Sulfur Fuel (0.05 wt. pct. S) + Limited Operation	50	0.005	0.0050
		Limited Operation (0.1 wt. pct. S) (existing)	0	0.01	0
11, 12	Propane-Fired Boiler	Low Sulfur Fuel (existing)	0	0.0002	0

Table 5-4. Annualized Costs for ULSD on the Diesel-fired Simple Cycle Gas Turbine (EU ID 1)

Shaded cells indicate user inputs

Project: GVEA North Pole - $PM_{2.5}$ BACT Analysis (EU ID 1 - GE Frame 7 CT)

Prepared By:
Checked By:
Rev:

Annualized Costs

DIRECT ANNUAL COSTS	QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1) Operating & Maintenance Costs		%			$ -	$ -
(2) Repair & Replacement Costs		%			$ -	$ -
(3) Maintenance Materials		LOT		excluded in this estimate		
(4) Utilities						
(a) ULSD Costs:	45,282,462	GAL	$ 0.424	$ 19,199,764		$ 19,199,764
Total Direct Annual Costs (TDAC)					**TDAC =**	$ 19,199,764
INDIRECT ANNUAL COSTS						
(5) Overhead		%		excluded in this estimate	$ -	$ -
(6) Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
Capital Recovery Factor [see inputs below]	0.0944					
(7) Capital Recovery					**CRF * TCI =**	$ -
Total Indirect Annual Costs (TIAC) (refer to Table 5-10)					**TIAC =**	$ 1,461,566
TOTAL ANNUALIZED COSTS (TAC)					**TAC = (TDAC) + (TIAC) =**	$ 20,661,330

Cost Effectiveness Summary

TOTAL TONS SO_2 AVOIDED PER YEAR	=	1,482
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON PTE)	**(TAC)/(TPY) =**	$ 13,942
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON ACTUAL HISTORIC RUN TIMES, AVOIDING 111 TONS PER YEAR)[1]	**(TAC)/(TPY) =**	$ 25,530
COST EFFECTIVENESS ($ PER TON PM AVOIDED BASED ON 6 TONS SO_2 AVOIDED = 1 TON PM AVOIDED)[2]	**(TAC)/(TPY) =**	$ 153,183

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	20	years

[1] Annual average run hours for EU 1 from 2009-2016 is 833 hours, and the peak in the last four years has been 587 hours. 833 hours equates to 4,305,969 gallons of fuel, a TDAC of $1,791,283, and a TAC of $3,208,769. The capital cost of bulk fuel storage would be less and the TIAC for actuals is shown in Table 5-10. 4,305,969 gallons of .381 wt pct. S replaced with .0015 wt pct. = 111 tons avoided. Monthly testing of No. 2 HSD for 2017 showed 0.381 wt. pct. S. average

[2] Alaska Department of Environmental Conservation, Amendments to State Air Quality Control Plan Vol. III: Appendix III.D.5.7, page 52. In reference to fuel oil emissions, "Ambient sampling and modeling in FNSB indicates that reduction of six tons of SO_X emissions result in the same reduction in ambient $PM_{2.5}$ concentration as the reduction of one ton of directly emitted $PM_{2.5}$".

Table 5-5. Annualized Costs for ULSD on the Diesel-fired Simple Cycle Gas Turbine (EU ID 2)

Shaded cells indicate user inputs

Project: GVEA North Pole - $PM_{2.5}$ BACT Analysis (EU ID 2 - GE Frame 7 CT)

Prepared By:
Checked By:
Rev:

Annualized Costs

DIRECT ANNUAL COSTS	QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1) Operating & Maintenance Costs		%			$ -	$ -
(2) Repair & Replacement Costs		%			$ -	$ -
(3) Maintenance Materials		LOT		excluded in this estimate		
(4) Utilities						
(a) ULSD Costs:	41,312,492	GAL	$ 0.424	$ 17,516,497		$ 17,516,497
Total Direct Annual Costs (TDAC)					TDAC =	$ 17,516,497
INDIRECT ANNUAL COSTS						
(5) Overhead		%		excluded in this estimate	$ -	$ -
(6) Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
Capital Recovery Factor [see inputs below]	0.0944					
(7) Capital Recovery					CRF * TCI =	$ -
Total Indirect Annual Costs (TIAC) **(refer to Table 5-10)**					TIAC =	$ 1,461,566
TOTAL ANNUALIZED COSTS (TAC)					TAC = (TDAC) + (TIAC) =	$ 18,978,063

Cost Effectiveness Summary

TOTAL TONS SO_2 AVOIDED PER YEAR	=	1,352
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON PTE)	(TAC)/(TPY) =	$ 14,037
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON ACTUALS, AVOIDING 330 TONS PER YEAR)[1]	(TAC)/(TPY) =	$ 19,497
COST EFFECTIVENESS ($ PER TON PM AVOIDED BASED ON 6 TONS SO_2 AVOIDED = EQUIVALENT TO 1 TON PM AVOIDED)[2]	(TAC)/(TPY) =	$ 116,981

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	20	years

[1] Annual average run hours for EU 2 from 2009-2016 is 2472 hours, and the peak in the last four years has been 2873 hours. 2472 hours equates to 12,778,338 gallons of fuel, a TDAC of $5,315,789 and a TAC of $6,730,274. The capital cost of bulk fuel storage would be less and the TIAC for actuals is shown in Table 5-10. 12,778,338 gallons of .381 wt pct. S replaced with .0015 wt pct. = 330tons avoided. Monthly testing of No. 2 HSD for 2017 showed 0.381 wt. pct. S. average

[2] Alaska Department of Environmental Conservation, Amendments to State Air Quality Control Plan Vol. III: Appendix III.D.5.7, page 52. In reference to fuel oil emissions, "Ambient sampling and modeling in FNSB indicates that reduction of six tons of SO_x emissions result in the same reduction in ambient $PM_{2.5}$ concentration as the reduction of one ton of directly

Table 5-6. Annualized Costs for ULSD on the Diesel-fired Combined Cycle Gas Turbines (EU IDs 5 and 6)

Shaded cells indicate user inputs

Project: GVEA North Pole - $PM_{2.5}$ BACT Analysis (EU IDs 5 and 6 - GE LM6000PC CT)

Prepared By:
Checked By:
Rev:

Annualized Costs

		QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
DIRECT ANNUAL COSTS							
(1)	Operating & Maintenance Costs		%			$ -	$ -
(2)	Repair & Replacement Costs		%			$ -	$ -
(3)	Maintenance Materials		LOT		excluded in this estimate		
(4)	Utilities						
	(a) ULSD Costs:	30,660,000	GAL	1.117	$ 34,247,220		$ 34,247,220
Total Direct Annual Costs (TDAC)						**TDAC =**	$ 34,247,220
INDIRECT ANNUAL COSTS							
(5)	Overhead		%		excluded in this estimate	$ -	$ -
(6)	Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
	Capital Recovery Factor [see inputs below]	0.0944					
(7)	Capital Recovery					**CRF * TCI =**	$ -
Total Indirect Annual Costs (TIAC)						**TIAC =**	$ -
TOTAL ANNUALIZED COSTS (TAC)						**TAC = (TDAC) + (TIAC) =**	$ 34,247,220

Cost Effectiveness Summary

TOTAL TONS SO_2 AVOIDED PER YEAR	=	7.1
COST EFFECTIVENESS ($ PER TON AVOIDED)	**(TAC)/(TPY) =**	$ 4,844,020

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	20	years

Table 5-7. Annualized Costs for ULSD on the Diesel-fired Emergency Generator Engine (EU ID 7)

Shaded cells indicate user inputs

Project: GVEA North Pole - $PM_{2.5}$ BACT Analysis (EU ID 7 - Generac Gen Set Engine)

Prepared By:
Checked By:
Rev:

Annualized Costs

	DIRECT ANNUAL COSTS	QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1)	Operating & Maintenance Costs		%			$ -	$ -
(2)	Repair & Replacement Costs		%			$ -	$ -
(3)	Maintenance Materials		LOT		excluded in this estimate		
(4)	Utilities						
	(a) ULSD Costs:	1,664	GAL	0.2668	$ 444		$ 444
	Total Direct Annual Costs (TDAC)					TDAC =	$ 444
	INDIRECT ANNUAL COSTS						
(5)	Overhead		%		excluded in this estimate	$ -	$ -
(6)	Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
	Capital Recovery Factor [see inputs below]	0.0944					
(7)	Capital Recovery					CRF * TCI =	$ -
	Total Indirect Annual Costs (TIAC)					TIAC =	$ -
	TOTAL ANNUALIZED COSTS (TAC)					TAC = (TDAC) + (TIAC) =	$ 444

Cost Effectiveness Summary

TOTAL TONS SO_2 AVOIDED PER YEAR	=	0.00985
COST EFFECTIVENESS ($ PER TON AVOIDED)	(TAC)/(TPY) =	$ 45,072

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	20	years

Table 5-8. GVEA North Pole Facility - SO_2 BACT Cost Effectiveness

Summary[1] for Each Emission Unit Based on PTE

Control Technology Option	SO2 Emissions (tpy)	Total Installed Capital ($)	Total Annualized Cost ($/year)	Annual O&M Cost ($/year)	Cost Effectiveness ($/ton SO2 removed)
Simple Cycle Gas Turbine (EU ID 1)					
ULSD (0.0015 wt. pct. S)	4	$10,875,319	$20,661,330	$19,199,764	$13,942
No. 1 HSD (0.100 wt. pct. S)	297	~	$226,412	$226,412	$1,904
Good Combustion Practices (0.50 wt. pct. S) (existing)	1,486	~	~	~	~
Simple Cycle Gas Turbine (EU ID 2)					
Limited Operation + ULSD (0.0015 wt. pct. S)	4	$10,875,319	$18,978,063	$17,516,497	$14,037
Limited Operations + No. 1 HSD (0.100 wt. pct. S)	271	~	$206,562	$206,562	$1,904
Good Combustion Practices (0.50 wt. pct. S) (existing)	1,356	~	~	~	~
Combined Cycle Gas Turbines (EU IDs 5 and 6)					
ULSD (0.0015 wt. pct. S)	3	~	$34,247,220	~	$4,844,020
LSR/Naphtha (0.0050 wt. pct. S) + Good Combustion Practices (existing)	10	~	~	~	~
Emergency Generator Engine (EU ID 7)					
ULSD (0.0015 wt. pct. S) + Limited Operation	0.0002	~	$444	~	$45,072
Limited Operation (0.1 wt. pct. S) (existing)	0.01	~	~	~	~
Propane Fired Boilers (EU IDs 11 and 12)					
Low Sulfur Fuel (propane) (existing)	0	~	~	~	~

[1] All emission costs are on a per emission unit basis.

Table 5-9. GVEA North Pole Facility - Proposed SO_2 BACT and Associated Emission Rate for Each Emission Unit

ID	Description		Description	Emission Rate[1]
1, 2	Simple Cycle Gas Turbine	Fuel Oil	Good Combustion Practices (existing) + No. 1 HSD on air quality curtailment days	500 ppm S in fuel
5, 6	Combined Cycle Gas Turbine	LSR	LSR/Naphtha (existing)	50 ppm S in fuel
7	Emergency Generator Engine	Fuel Oil	Good Combustion Practices (existing)	500 ppm S in fuel
11, 12	Boiler	Propane	Low Sulfur Fuel - Propane (existing)	0.0012 lb/kgal

[1] Emissions are on a per emission unit basis.

Table 5-10. Capital Cost for New ULSD Storage Based on Maximum Fuel Use and Actual Fuel Use

	North Pole EUs 1 and 2 Maximum Fuel Use	Zehnder EUs 1 and 2 Maximum Fuel Use	North Pole EUs 1 and 2 Actual Fuel Use	Zehnder EUs 1 and 2 Actual Fuel Use
Capital Cost Estimate	$30,425,000		$21,050,000	
Heat Input, MMBtu/day (combined for each set of combustion turbines)	32,256	12,864	32,256	12,864
Percentage of Heat Input	71.5%	28.5%	71.5%	28.5%
Capital Cost (apportioned based on heat input ratio)	$ 21,750,638	$ 8,674,362	$ 15,048,511	$ 6,001,489
Capital Cost (apportioned per combustion turbine)	$ 10,875,319	$ 4,337,181	$ 7,524,255	$ 3,000,745
Capital Recovery (per combustion turbine)	$ 1,026,553	$ 409,399	$ 710,236	$ 283,249
Administrative Charges, Property Taxes, Insurance (per combustion turbine)	$ 435,013	$ 173,487	$ 300,970	$ 120,030
Total Annual Indirect Cost (per combustion turbine)	**$ 1,461,566**	**$ 582,886**	**$ 1,011,207**	**$ 403,279**

Capital recovery factor 0.0944

Data Inputs for Capital Recovery Factor:

Annual Interest Rate (EPA OAQPS Control Cost Manual) 7.00 pct.

Project Life (EPA OAQPS Control Cost Manual) 20 years

Administrative Charges, Property Taxes Insurance (percentage of total capital cost) 4.00%

Capital cost estimate for 1.27 million gallons of storage capacity.

GVEA
Alternative BACT
November 2018

Attachment 5b
Updated Cost Effectiveness Tables Zehnder

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Table 5-1. GVEA - Zehnder Facility - Summary of Available SO_2 Emission Control Technologies

Emission Unit		Available Emission Control Technology
ID	Description	
1, 2	Simple Cycle Gas Turbine	ULSD
		Low Sulfur Fuel
		Good Combustion Practices
3, 4	Diesel-fired Emergency Generator Engine	ULSD
		Low Sulfur Fuel
		Limited Operations
		Good Combustion Practices
10, 11	Diesel-fired Boiler	ULSD
		Low Sulfur Fuel
		Good Combustion Practices

Table 5-2. GVEA - Zehnder Facility - Summary of Technically Feasible SO_2 Emission Control Technologies

Emission Unit		Emission Control Technology
ID	Description	
1,2	Simple Cycle Combustion Gas Turbine	ULSD
		Low Sulfur Fuel
		Good Combustion Practices
3, 4	Diesel-fired Emergency Generator Engine	ULSD
		Low Sulfur Fuel
		Limited Operation
		Good Combustion Practices
10, 11	Diesel-fired Boiler	ULSD
		Low Sulfur Fuel
		Good Combustion Practices

Table 5-3. GVEA - Zehnder Facility - Ranking of Technically Feasible SO_2 Emission Control Technology

Emission Unit		Control Technology Used	Control Efficiency (pct)[2]	SO_2 Emissions Per Unit (tpy)	SO_2 Emissions Reduction (tpy)
ID	Description				
1, 2[1]	Simple Cycle Combustion Gas Turbines	ULSD Fuel (0.0015 wt. pct. S)	99.7	1.8	578.2
		Low-Sulfur Fuel (0.05 wt. pct. S)	89.8	59.3	520.7
		Good Combustion Practices (0.5 wt. pct. S) (existing)	0	580	0
3, 4[1]	Diesel-fired Emergency Generator Engines	ULSD Fuel (0.0015 wt. pct. S)	99.7	0.01	3.7
		Low-Sulfur Fuel (0.05 wt. pct. S)	90.0	0.37	3.3
		Limited Operation and Good Combustion Practices (0.5 wt. pct. S) (existing)	0	3.7	0
10, 11[1]	Diesel-fired Boilers	ULSD Fuel (0.0015 wt. pct. S)	99.7	0.012	3.8
		Low-Sulfur Fuel (0.05 wt. pct. S)	90.0	0.39	3.5
		Good Combustion Practices (0.5 wt. pct. S) (existing)	0	3.9	0

Note:

[1] Combined SO_2 emissions from EU IDs 1 through 4, 10, and 11 are limited to 580 tpy on a 12-month rolling basis per Permit AQ0109TVP03 Condition 9. Each emission unit can operate individually up to the potential emissions listed in this table. The fuel sulfur content is limited to 1.0 wt. pct. for EU IDs 1 through 4, per Permit AQ0109TVP03, Condition 10. However, No. 1 and No. 2 fuel oil (by specification) can have a maximum sulfur content of 0.5 wt. pct., so 0.5 percent fuel sulfur content is used as the baseline for each emission unit.

[2] The use of low-sulfur fuel and ULSD both result in the 580 tpy SO_2 limit being unncessary. For each emission unit, the control efficiencies are based on the emission reduction between the existing PTE and the PTE that would result due to the use of lower sulfur fuel.

Table 5-4. Annualized Costs for ULSD Combustion in the Diesel-fired Simple Cycle Gas Turbines (EU ID 1 and 2)

Shaded cells indicate user inputs

Cost Effectiveness Determination - ULSD Fuel Switch - No Additional Tank Storage

Project: GVEA Zhender - SO_2 BACT Analysis (EU ID 1 and 2 - Frame 5 CTs, cost per turbine)

Date:
Prepared By:
Checked By:
Rev:

Annualized Costs

DIRECT ANNUAL COSTS		QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1)	Operating & Maintenance Costs		%			$ -	$ -
(2)	Repair & Replacement Costs		%			$ -	$ -
(3)	Maintenance Materials		LOT				
(4)	Utilities						
	(a) ULSD Costs:	18,059,076.92	GAL	0.424	$ 7,657,049		$ 7,657,049
Total Direct Annual Costs (TDAC)						TDAC =	$ 7,657,049
INDIRECT ANNUAL COSTS							
(5)	Overhead		%			$ -	$ -
(6)	Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
	Capital Recovery Factor [see inputs below]	0.0944					
(7)	Capital Recovery					CRF * TCI =	$ -
Total Indirect Annual Costs (TIAC) (refer to Table 5-10)						TIAC =	$ 582,886
TOTAL ANNUALIZED COSTS (TAC)						TAC = (TDAC) + (TIAC) =	$ 8,239,935

Cost Effectiveness Summary

TOTAL TONS SO2 AVOIDED PER YEAR	=	578
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON PTE)	(TAC)/(TPY) =	$ 14,250
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON ACTUAL HISTORIC RUN TIMES, AVOIDING 51.9 TONS PER YEAR)[1]	(TAC)/(TPY) =	$ 20,734
COST EFFECTIVENESS ($ PER TON PM AVOIDED BASED ON 6 TONS SO_2 AVOIDED = 1 TON PM AVOIDED)[2]	(TAC)/(TPY) =	$ 124,401

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	20	years

[1] Annual average run hours of 770 for EU IDs 1 and 2, see Table 5-9. 700 hours equates to 1,587,385 gallons of fuel, a TDAC of $423,514 and a TAC of $970,728. The capital cost of bulk fuel

[2] Alaska Department of Environmental Conservation, Amendments to State Air Quality Control Plan Vol. III: Appendix III.D.5.7, page 52. In reference to fuel oil emissions, "Ambient sampling and

Table 5-5. Annualized Costs for ULSD Combustion in the Diesel-fired Engines (EU ID 3 and 4)

Shaded cells indicate user inputs

Cost Effectiveness Determination - ULSD Fuel Switch - No Additional Tank Storage

Project: GVEA Zhender - SO_2 BACT Analysis (EU ID 3 and 4 - General Motors Gen Set Engines, cost per engine)

Date:
Prepared By:
Checked By:
Rev:

Annualized Costs

	DIRECT ANNUAL COSTS	QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1)	Operating & Maintenance Costs		%			$ -	$ -
(2)	Repair & Replacement Costs		%			$ -	$ -
(3)	Maintenance Materials		LOT				
(4)	Utilities						
	(a) ULSD Costs:	107,692.31	GAL	0.2668	$ 28,732		$ 28,732
	Total Direct Annual Costs (TDAC)					**TDAC =**	$ 28,732
	INDIRECT ANNUAL COSTS						
(5)	Overhead		%			$ -	$ -
(6)	Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
	Capital Recovery Factor [see inputs below]	0.1424					
(7)	Capital Recovery					**CRF * TCI =**	$ -
	Total Indirect Annual Costs (TIAC)		**Not applicable**			**TIAC =**	$ -
	TOTAL ANNUALIZED COSTS (TAC)					**TAC = (TDAC) + (TIAC) =**	$ 28,732

Cost Effectiveness Summary

TOTAL TONS SO2 AVOIDED PER YEAR	= 3.7
COST EFFECTIVENESS ($ PER TON AVOIDED)	**(TAC)/(TPY) =** $ 7,768

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	10	years

Table 5-6 Annualized Costs for ULSD Combustion in the Diesel-fired Boilers (EU ID 10 and 11)

Shaded cells indicate user inputs

Cost Effectiveness Determination - ULSD Fuel Switch - No Additional Tank Storage

Project: GVEA Zhender - SO_2 BACT Analysis (EU ID 10 and 11 - Weil McLain Boilers, cost per boiler)

Date:
Prepared By:
Checked By:
Rev:

Annualized Costs

DIRECT ANNUAL COSTS		QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1)	Operating & Maintenance Costs		%			$ -	$ -
(2)	Repair & Replacement Costs		%			$ -	$ -
(3)	Maintenance Materials		LOT				
(4)	Utilities						
	(a) ULSD Costs:	114,553.85	GAL	0.2668	$ 30,563		$ 30,563
Total Direct Annual Costs (TDAC)						TDAC =	$ 30,563
INDIRECT ANNUAL COSTS							
(5)	Overhead		%			$ -	$ -
(6)	Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
	Capital Recovery Factor [see inputs below]	0.1424					
(7)	Capital Recovery					CRF * TCI =	$ -
Total Indirect Annual Costs (TIAC)			Not applicable			TIAC =	$ -
TOTAL ANNUALIZED COSTS (TAC)						TAC = (TDAC) + (TIAC) =	$ 30,563

Cost Effectiveness Summary

TOTAL TONS SO2 AVOIDED PER YEAR	=	3.8
COST EFFECTIVENESS ($ PER TON AVOIDED)	(TAC)/(TPY) =	$ 7,946

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	10	years

Table 5-7. GVEA - Zehnder Facility - SO_2 BACT Cost Effectiveness Summary for Each Emission Unit

Emission Control Technology	SO_2 Emissions (tpy)	Total Installed Capital ($)	Total Annualized Cost ($/year)	Annual O&M Cost ($/year)	Cost Effectiveness ($/ton SO_2 removed)
Diesel-fired Simple Cycle Gas Turbines (EU IDs 1 and 2, per turbine)					
ULSD Fuel (0.0015 wt. pct. S)	1.8	$4,337,181	$8,239,935	$7,657,049	$14,250
Good Combustion Practices (0.5 wt. pct. S) (existing)	580	~	~	~	~
Emergency Generator Engines (EU IDs 3 and 4, per engine)					
ULSD Fuel (0.0015 wt. pct. S)	0.01	~	$28,732	$28,732	$7,768
Limited Operation and Good Combustion Practices (0.5 wt. pct. S) (existing)	3.71	~	~	~	~
Diesel-fired Boilers (EU IDs 10 and 11, per boiler)					
ULSD Fuel (0.0015 wt. pct. S)	0.01	~	$30,563	$30,563	$7,946
Good Combustion Practices (0.5 wt. pct. S) (existing)	3.9	~	~	~	~

Note:
All costs are on a per unit basis.

Table 5-8. GVEA - Zehnder Facility - Proposed SO_2 BACT and Associated Emission Rate for Each Emission Unit

Emission Unit		Fuel	SO_2 BACT	
ID	Description		Description	Sulfur Content of Fuel
1, 2	Simple Cycle Gas Turbines	Fuel Oil	Fuel Oil and Good Combustion Practices (existing) - Refer to Table 5-9	0.5 wt. pct. S
3, 4	Emergency Generator Engines	Diesel	Fuel Oil and Good Combustion Practices (existing)	0.5 wt. pct. S
10, 11	Boilers	Diesel	ULSD	0.0015 wt. pct. S

Note:
[1] Emissions are on a per unit basis.

Table 5-9. GVEA - Zehnder Facility - SO_2 BACT Analysis for EU IDs 1 and 2 Based on Actual Operations

	SO_2 BACT Analysis Based on Potential Emissions	SO_2 BACT Analysis Based on Actual (Historical) Operations
Operating Basis	8,760 hr/yr	770 hr/yr
Emissions (EU 1 or EU 2)	580.0 tpy	52.1 tpy
Good combustion practices, 0.5 wt. pct. S (existing)		
PTE	580.0 tpy	52.1 tpy
PTE reduction	0.0 tpy	0.0 tpy
Cost effectiveness	N/A	N/A
ULSD Fuel (0.0015 wt. pct. S)		
PTE	1.8 tpy	0.2 tpy
PTE reduction	578.2 tpy	51.9 tpy
Total Direct annual Costs (TDAC)	$ 7,657,049 (Table 5-4)	$ 673,051 [1]
Total Indirect Annual Costs (TIAC)	$ 582,886 (Table 5-10)	$ 403,279 (Table 5-10)
Total annualized Costs (TAC = TDAC + TIAC)	$ 8,239,935	$ 1,076,330
Cost effectiveness	14,250 $/ton	20,734 $/ton

[1] Assuming 770 hours, 268 MMBtu/Hr, and .13 MMBtu/gal, for 1,587,385 gallons, and the fuel costs shown in Table 5-4)

Notes:

1. Historical Operating Hours

Year	EU 1	EU 2	Total
2007	267	529	797
2008	745	57	802
2009	**833**	408	1,241
2010	527	1,012	**1,539**
2011	756	509	1,265
2012	440	635	1,075
2013	226	936	1,162
2014	139	1,068	1,207
2015	339	991	1,330
2016	93	**1,137**	1,230

*2016 is not representative of typical use because EU 1 has been down waiting for a rebuild.

*Maximum annual operating hours for each turbine and total are shown in bold.

*The basis for this analysis is half of the total hours from 2010 for each turbine (770 hr/yr).

2. Basis for Emissions Calculations

SO_2 Emission Factor for EUs 1 and 2

Fuel with 0.5 wt. pct. S content	0.51	lb/MMBtu (AP-42 Table 3.1-2a)
Fuel with 0.05 wt. pct. S content	0.051	lb/MMBtu (AP-42 Table 3.1-2a)
Fuel with 0.015 wt. pct. S content	0.015	lb/MMBtu (AP-42 Table 3.1-2a)
Heat input capacity for EUs 1 and 2	268	MMBtu/hr

Total Annual Costs

Emission Control Technology	Control Efficiency (pct) from Table 5-3
ULSD Fuel (0.0015 wt. pct. S)	99.7
Good Combustion Practices (existing)	0

Table 5-10. Capital Cost for New ULSD Storage Based on PTE Maximum Fuel Use and Historic Actual Use

	North Pole EUs 1 and 2 Maximum Fuel Use	Zehnder EUs 1 and 2 Maximum Fuel Use	North Pole EUs 1 and 2 Actual Fuel Use	Zehnder EUs 1 and 2 Actual Fuel Use
Capital Cost Estimate	$30,425,000		$21,050,000	
Heat Input, MMBtu/day (combined for each set of combustion turbines)	32,256	12,864	32,256	12,864
Percentage of Heat Input	71.5%	28.5%	71.5%	28.5%
Capital Cost (apportioned based on heat input ratio)	$ 21,750,638	$ 8,674,362	$ 15,048,511	$ 6,001,489
Capital Cost (apportioned per combustion turbine)	$ 10,875,319	$ 4,337,181	$ 7,524,255	$ 3,000,745
Capital Recovery (per combustion turbine)	$ 1,026,553	$ 409,399	$ 710,236	$ 283,249
Administrative Charges, Property Taxes, Insurance (per combustion turbine)	$ 435,013	$ 173,487	$ 300,970	$ 120,030
Total Annual Indirect Cost (per combustion turbine)	**$ 1,461,566**	**$ 582,886**	**$ 1,011,207**	**$ 403,279**

Capital recovery factor	0.0944	

Data Inputs for Capital Recovery Factor:

Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	pct.
Project Life (EPA OAQPS Control Cost Manual)	20	years
Administrative Charges, Property Taxes Insurance (percentage of total capital cost)	4.00%	

Table E-1a. Summary of Identified SO_2 Control Technology - Liquid Fuel-Fired Simple Cycle Turbines > 25 MW (RBLC 15.190)

Pollutant	Control Technology Used	Number of RBLC Entries (11 Total)
SO_2	Low Sulfur Fuel	7
	None	4

Note: Data is based on a RBLC review from January 1, 2005 through September 15, 2015.

Table E-1b. Summary of Identified SO_2 Control Technology - Large Diesel Engines > 500 hp (RBLC 17.110)

Pollutant	Control Technology Used	Number of RBLC Entries (30 Total)
SO_2	Low-Sulfur Fuel	13
	ULSD Fuel	7
	None	3
	Good Combustion Practices	5
	NSPS Standards	2

Note: Data is based on a RBLC review from January 1, 2005 through September 15, 2015.

Table E-1c. Summary of Identified SO_2 Control Technology - Diesel-Fired Commercial/Institutional Boilers <100 MMBtu/hr (RBLC 13.220)

Pollutant	Control Technology Used	Number of RBLC Entries (6 Total)
SO_2	Low Sulfur Fuel	2
	Low Sulfur Fuel + Good Combustion Practices	2
	Wet or Dry Scrubber + Good Combustion Practices	1
	None	1

Note: Data is based on a RBLC review from January 1, 2005 through September 15, 2015.

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Attachment 6
Tables 5-4a and 5-5a, North Pole EU ID 1 and 2 Cost Effectiveness with selective use of No. 1 HSD

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Table 5-5b. Annualized Costs for No. 1 HSD on the Diesel-fired Simple Cycle Gas Turbine (EU ID 2)

Shaded cells indicate user inputs

Project: GVEA North Pole - $PM_{2.5}$ BACT Analysis (EU ID 2 - GE Frame 7 CT)

Prepared By:
Checked By:
Rev:

Annualized Costs

DIRECT ANNUAL COSTS		QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1)	Operating & Maintenance Costs		%			$ -	$ -
(2)	Repair & Replacement Costs		%			$ -	$ -
(3)	Maintenance Materials		LOT		excluded in this estimate		
(4)	Utilities			10%	Estimated time running No. 1		
	(a) No 1 Costs:	41,312,492	GAL	0.05	$ 206,562		$ 206,562
Total Direct Annual Costs (TDAC)						TDAC =	$ 206,562
INDIRECT ANNUAL COSTS							
(5)	Overhead		%		excluded in this estimate	$ -	$ -
(6)	Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
	Capital Recovery Factor [see inputs below]	0.0944					
(7)	Capital Recovery					CRF * TCI =	$ -
Total Indirect Annual Costs (TIAC)						TIAC =	$ -
TOTAL ANNUALIZED COSTS (TAC)						TAC = (TDAC) + (TIAC) =	$ 206,562

Cost Effectiveness Summary

TOTAL TONS SO_2 AVOIDED PER YEAR [1]	=	108
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON PTE) (TAC)/(TPY) =	$	1,904

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	20	years

[1] Assuming PTE and running No. 1 HSD 10% of the days. Running No. 1 on curtailment days.

Table 5-4a. Annualized Costs for No. 1 HSD on the Diesel-fired Simple Cycle Gas Turbine (EU ID 1)

Shaded cells indicate user inputs

Project: GVEA North Pole - $PM_{2.5}$ BACT Analysis (EU ID 1 - GE Frame 7 CT)

Prepared By:
Checked By:
Rev:

Annualized Costs

DIRECT ANNUAL COSTS	QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1) Operating & Maintenance Costs		%			$ -	$ -
(2) Repair & Replacement Costs		%			$ -	$ -
(3) Maintenance Materials		LOT		excluded in this estimate		
(4) Utilities			10%	Estimated time running No. 1		
(a) ULSD Costs:	45,282,462	GAL	0.05	$ 226,412		$ 226,412
Total Direct Annual Costs (TDAC)					**TDAC =**	$ 226,412
INDIRECT ANNUAL COSTS						
(5) Overhead		%		excluded in this estimate	$ -	$ -
(6) Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
Capital Recovery Factor [see inputs below]	0.0944					
(7) Capital Recovery					**CRF * TCI =**	$ -
Total Indirect Annual Costs (TIAC)					**TIAC =**	$ -
TOTAL ANNUALIZED COSTS (TAC)					**TAC = (TDAC) + (TIAC) =**	$ 226,412

Cost Effectiveness Summary

TOTAL TONS SO_2 AVOIDED PER YEAR	=	119
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON PTE)	**(TAC)/(TPY) =**	$ 1,904

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	20	years

[1] Assuming PTE and running No. 1 HSD 10% of the days. Running No. 1 on curtailment days.

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Attachment 7
Zehnder FY2019 Assessable Emissions Summary

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Table 1. FY2019 Assessable Emissions Summary
Golden Valley Electric Association - Zehnder Facility

Assessable Emissions - Tons Per Year							
Description	**NO_X**	**CO**	**PM_{10}**	**SO_2**	**VOC**	**HAPs**	**Total**
Assessable PTE	2,854	217	746	580	23	-	4,420

From Condition 30 and Table C of the SOB for AQ0109TVP03

Potential to Emit	**Regulated Air Pollutant Emissions (tons per year)** [1]					
	NO_X	**CO**	**PM_{10}**	**VOC**	**SO_2**	**HAP**
Significant	70.8	0.3	1.0	0.0	30.1	
Insignificant	0.2	0.1	0.0	0.0	0.5	
Total Emissions	**71**	**0**	**1**	**0**	**31**	
Use Assessable PTE						**0**
Assessable Emission Subtotals	**71**	**0**	**1**	**0**	**31**	**0**
Fees Apply to Pollutant? [2]	**Yes**	**No**	**No**	**No**	**Yes**	**No**
2017 Actual Emissions	**102**					
Fee Estimate [3]	**$4,366**					

Notes:

[1] Regulated air pollutant calculations based on emission factors shown in accompanying spreadsheets.

[2] Fees paid on each pollutant emitted in quantities greater than 10 tpy per 18 AAC 50.410.

[3] A fee rate of $42.95 per ton applies in accordance with 18 AAC 50.410(b)(1).

[4] Actual emissions are not provided for HAPs because potential emissions for HAPs are less than 10 tpy. Actual emissions must be less than or equal to potential emissions, so actual emissions are also less than 10 tpy.

Table 2a. FY2019 Significant Emission Unit Summary
Golden Valley Electric Association - Zehnder Facility

Emission Unit			Fuel	2017 Actual	Maximum	2017 Actual
ID	Description	Make/Model	Type	Operation	Capacity	Fuel Consumption
1	Simple Cycle Gas Turbine	General Electric Frame 5 MS 5001-M	No. 1 Diesel	0.3 hr/yr	268 MMBtu/hr	90 gal/yr
			No. 2 Diesel			0 gal/yr
2	Simple Cycle Gas Turbine	General Electric Frame 5 MS 5001-M	No. 1 Diesel	1,133.4 hr/yr	268 MMBtu/hr	88,231 gal/yr
			No. 2 Diesel			1,072,989 gal/yr
3	Diesel Generator Engine	General Motors Electro-Motive Diesel 20-645E4	No. 2 Diesel	2.7 hr/yr	28 MMBtu/hr	588 gal/yr
4	Diesel Generator Engine	General Motors Electro-Motive Diesel 20-645E4	No. 2 Diesel		28 MMBtu/hr	
10	Boiler	Weil McLain H-688	No. 2 Diesel	755 hr/yr	1.7 MMBtu/hr	17,810 gal/yr
11	Boiler	Weil McLain H-688	No. 2 Diesel	755 hr/yr	1.7 MMBtu/hr	

Table 7. FY2019 Assessable Emission Calculations - Sulfur Dioxide (SO_2) Emissions
Golden Valley Electric Association - Zehnder Facility

Emission Unit		Fuel	Factor	Fuel	SO_2 Emission	2017 Actual	2017 Actual SO_2
ID	Description	Type	Reference	Sulfur Content [1,2]	Factor	Operation	Emissions
1	Simple Cycle Gas Turbine	No. 1 Diesel	Mass Balance	0.095 wt. pct. S	0.013 lb/gal	90 gal/yr	5.8E-04 tpy
		No. 2 Diesel	Mass Balance	0.381 wt. pct. S	0.054 lb/gal	0 gal/yr	0 tpy
2	Simple Cycle Gas Turbine	No. 1 Diesel	Mass Balance	0.095 wt. pct. S	0.013 lb/gal	88,231 gal/yr	0.57 tpy
		No. 2 Diesel	Mass Balance	0.381 wt. pct. S	0.054 lb/gal	1,072,989 gal/yr	29.03 tpy
3	Diesel Generator Engine	No. 2 Diesel	Mass Balance	0.381 wt. pct. S	0.054 lb/gal	588 gal/yr	1.6E-02 tpy
4	Diesel Generator Engine	No. 2 Diesel					
10	Boiler	No. 2 Diesel	Mass Balance	0.381 wt. pct. S	0.054 lb/gal	17,810 gal/yr	0.48 tpy
11	Boiler	No. 2 Diesel					
Significant Emission Units - 2017 Actual Emissions - SO_2							**30.1 tpy**
Insignificant Emission Units							
6	Fuel Oil Storage Tank	No. 2 Diesel	N/A	N/A	N/A	8,760 hr/yr	0 tpy
7	Fuel Oil Storage Tank	No. 2 Diesel	N/A	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank	No. 1 Diesel	N/A	N/A	N/A	8,760 hr/yr	0 tpy
8	Burnham Boiler	No. 2 Diesel	Mass Balance	0.381 wt. pct. S	0.054 lb/gal	6,215 gal/yr	1.7E-01 tpy
9	Burnham Boiler	No. 2 Diesel	Mass Balance	0.381 wt. pct. S	0.054 lb/gal	6,215 gal/yr	1.7E-01 tpy
N/A	Burnham Boiler - FE Building	Natural Gas	AP-42 Table 1.4-2	2,000 gr/10^6scf	0.6 lb/10^6scf	1,069,200 scf	3.2E-04 tpy
N/A	Burnham Boiler - FE Building	Natural Gas					
N/A	Lean Burn Inc. CB 2800 Overhead Shop Heater	Waste Oil	Mass Balance	0.124 wt. pct. S	0.018 lb/gal	0 gal/yr	0 tpy
N/A	Energy Logic EL-340H Heater	Waste Oil	Mass Balance	0.124 wt. pct. S	0.018 lb/gal	1,238 gal/yr	1.1E-02 tpy
N/A	Metzger Machine Corp. Boiler	No. 2 Diesel	Mass Balance	0.381 wt. pct. S	0.054 lb/gal	5,808 gal/yr	1.6E-01 tpy
N/A	Energy Logic EL-200H Heater	Waste Oil - Transformer	Mass Balance	0.121 wt. pct. S	0.017 lb/gal	1,764 gal/yr	1.5E-02 tpy
N/A	Energy Logic EL-200H Heater	Waste Oil - Transformer	Mass Balance	0.121 wt. pct. S	0.017 lb/gal	1,383 gal/yr	1.2E-02 tpy
N/A	Energy Logic EL-350H Heater	Waste Oil - Transformer	Mass Balance	0.121 wt. pct. S	0.017 lb/gal	0 gal/yr	0 tpy
Insignificant Emission Units - 2017 Actual Emissions - SO_2							**0.53 tpy**
2017 Actual Emissions - SO_2							**30.6 tpy**

Sample Calculations: [3]

Molar mass ratio is 32 lb S/mol : 64 lb SO_2/mol

Stoichiometry: 1 mol S = 1 mol SO_2

Mass Balance Emission Factor, lb/gal = (Molar mass ratio, 2 lb SO_2:1 lb S) x (weight % S in fuel) x (density of fuel, lb/gal) / 100%

Emissions, tpy= (Emission factor, lb/gal) x (Fuel Use gal/yr) / (2,000 lb/ton)

Boiler Emissions, tpy= (Emission factor, lb/10^6scf) / (Conversion 1,000,000 scf/10^6scf) x (Fuel Consumption, scf) / (2,000 lb/ton)

Notes:

1 For diesel fuels, fuel sulfur content is the average of the monthly maximum fuel sulfur content values for calendar year 2017.

2 For waste oil and waste transformer oil, fuel sulfur content was determined by testing conducted in December 2016.

[3] Diesel fuel density is equal 6.8 lb/gal for No. 1 Diesel and 7.1 lb/gal for No. 2 Diesel per plant report.

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Attachment 8
House Freeze Up Time Estimates

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? HOUSE COOL DOWN MODEL

If more than twenty five (25) house/services involved in outage, Inside Temperature @ T(0) = 70 °F

Notify FNSB Emergency Services mCp = 2.5 kWh/°F = 8532.5 BTU/°F

to trigger Red Cross Assistance k = 0.16 kW/°F = 546.1 BTU/Hr-°F

	Time	Inside Temperature of House following loss of heat source												
	Hours	-80 F	-70 F	-60 F	-50 F	-40 F	-30 F	-20 F	-10 F	0 F	10 F	20 F	30 F	40 F
	0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
	1	60.7	61.3	61.9	62.6	63.2	63.8	64.4	65.0	65.7	66.3	66.9	67.5	68.1
Notification	2	52.0	53.2	54.4	55.6	56.8	58.0	59.2	60.4	61.6	62.8	64.0	65.2	66.4
Time	3	43.8	45.5	47.3	49.0	50.8	52.5	54.3	56.0	57.8	59.5	61.3	63.0	64.8
0% Freeze	4	36.1	38.4	40.6	42.9	45.2	47.4	49.7	51.9	54.2	56.4	58.7	61.0	63.2
	5	28.9	31.7	34.4	37.1	39.9	42.6	45.4	48.1	50.8	53.6	56.3	59.0	61.8
	6	22.2	25.4	28.5	31.7	34.9	38.1	41.3	44.5	47.7	50.9	54.1	57.2	60.4
	7	15.8	19.4	23.1	26.7	30.3	33.9	37.5	41.1	44.7	48.3	51.9	55.6	59.2
	8	9.9	13.9	17.9	21.9	25.9	29.9	33.9	37.9	42.0	46.0	50.0	54.0	58.0
Estimated	9	4.3	8.7	13.1	17.5	21.8	26.2	30.6	35.0	39.3	43.7	48.1	52.5	56.9
100% Freeze	10	-0.9	3.8	8.5	13.3	18.0	22.7	27.5	32.2	36.9	41.6	46.4	51.1	55.8
	11	-5.8	-0.8	4.3	9.4	14.4	19.5	24.5	29.6	34.6	39.7	44.7	49.8	54.8
	12	-10.4	-5.0	0.3	5.7	11.0	16.4	21.8	27.1	32.5	37.8	43.2	48.6	53.9
	13	-14.7	-9.1	-3.4	2.2	7.9	13.5	19.2	24.8	30.5	36.1	41.8	47.4	53.1
	14	-18.8	-12.9	-6.9	-1.0	4.9	10.8	16.7	22.7	28.6	34.5	40.4	46.3	52.2
	15	-22.6	-16.4	-10.2	-4.1	2.1	8.3	14.5	20.6	26.8	33.0	39.1	45.3	51.5
	16	-26.1	-19.7	-13.3	-6.9	-0.5	5.9	12.3	18.7	25.1	31.5	38.0	44.4	50.8
	17	-29.5	-22.8	-16.2	-9.6	-2.9	3.7	10.3	17.0	23.6	30.2	36.8	43.5	50.1
	18	-32.6	-25.8	-18.9	-12.1	-5.2	1.6	8.4	15.3	22.1	29.0	35.8	42.6	49.5
	19	-35.5	-28.5	-21.5	-14.4	-7.4	-0.4	6.7	13.7	20.7	27.8	34.8	41.9	48.9
	20	-38.3	-31.1	-23.9	-16.6	-9.4	-2.2	5.0	12.2	19.5	26.7	33.9	41.1	48.3
	21	-40.9	-33.5	-26.1	-18.7	-11.3	-3.9	3.5	10.9	18.3	25.6	33.0	40.4	47.8
	22	-43.3	-35.8	-28.2	-20.6	-13.1	-5.5	2.0	9.6	17.1	24.7	32.2	39.8	47.3
	23	-45.6	-37.9	-30.2	-22.5	-14.8	-7.1	0.7	8.4	16.1	23.8	31.5	39.2	46.9
	24	-47.7	-39.9	-32.0	-24.2	-16.3	-8.5	-0.6	7.2	15.1	22.9	30.8	38.6	46.5
	25	-49.7	-41.7	-33.8	-25.8	-17.8	-9.8	-1.8	6.2	14.1	22.1	30.1	38.1	46.1
	26	-51.6	-43.5	-35.4	-27.3	-19.2	-11.1	-3.0	5.2	13.3	21.4	29.5	37.6	45.7
	27	-53.4	-45.1	-36.9	-28.7	-20.5	-12.2	-4.0	4.2	12.4	20.7	28.9	37.1	45.3

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Golden Valley Electric Technology Determination (GVEA) North Pole Power Plant

- DEC Best Available Control Technology for GVEA –Zehnder Facility
- DEC letter to Ms. Knight (GVEA) on Request for additional information for BACT from GVEA for the North Pole Power Plant and Zehnder Facility by December 22, 2017 (dated November 16, 2017)
- DEC letter to Ms. Knight on Request for additional information for BACT Analysis Review – North Pole and Zehnder Facility BACT Analysis Review August 2017 (dated November 16, 2017)
- GVEA BACT Analysis Review Comments Reports EPA August 2017 (dated November 15, 2017)
- DEC letter to Ms. Knight (GVEA) on Voluntary BACT analysis for Zehnder Facility and North Pole Plant (dated April 24, 2015)
- GVEA response to DEC's Request for Additional Information for the BACT Technical Memorandum from GVEA for the North Pole Power Plant and Zehnder Facility (dated December 22, 2017)
- EPA Office of Air and Radiation – Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines (January 1993)
- DEC Request for Additional Information for BACT Memorandum from GVEA for the North Pole Power Plant and Zehnder Facility by November 1, 2018 (dated September 13, 2018)
- DEC Request for Additional Information GVEA – North Pole and Zehnder Facilities BACT Analysis Review August 2017 (dated September 10, 2018)
- EPA comments on DEC's Preliminary Draft Serious SIP Development for the Fairbanks nonattainment area
- BACT Proposal from GVEA for the North Pole and Zehnder Facilities (on November 28, 2018)
- GVEA Alternative BACT Attachment 1 – North Pole BACT 1 Tables (on November 2018)
- GVEA Alternative BACT Attachment 2 – Technical Memo from PDC Regarding Bulk Fuel Storage (on November 2018)
- GVEA Alternative BACT Attachment 3 - Leidos Strategic Fuel Evaluation (November 2018)
- GVEA Alternative BACT Attachment 4 – January 2017 through October 2018 Fuel Prices (November 2018)
- GVEA Alternative BACT Attachment 5a – Updated Cost Effectiveness Tables North Pole (November 2018)
- GVEA Alternative BACT Attachment 5b – Updated Cost Effectiveness Tables North Pole (November 2018)
- GVEA Alternative BACT Attachment 6 – Tables 5-4a and 5-5a, North Pole EU ID 1 AND 2 Cost Effectiveness with Selective Use of No. 1 HSD (November 2018)
- GVEA Alternative BACT Attachment 7 – Zehnder FY2019 Assessable Emissions Summary (November 2018)
- GVEA Alternative BACT Attachment 8 – House Freeze Up Time Estimates

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
Air Permits Program

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION
for
Golden Valley Electric Association
North Pole Power Plant

Prepared by: Brittany Crutchfield
Supervisor: Patrick Dunn
Preliminary Date: May 10, 2019

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Abbreviations/Acronyms

AAC .....Alaska Administrative Code
AAAQS .....Alaska Ambient Air Quality Standards
Department .....Alaska Department of Environmental Conservation
BACT .....Best Available Control Technology
CFB……Circulating Fluidized Bed
CFR. .....Code of Federal Regulations
Cyclones…….Mechanical Separators
DFP……Diesel Particulate Filter
DLN.....Dry Low NOx
DOC……..Diesel Oxidation Catalyst
EPA .....Environmental Protection Agency
ESP…….Electrostatic Precipitator
EU.....Emission Unit
FITR……..Fuel Injection Timing Retard
GCPs……..Good Combustion Practices
HAP.....Hazardous Air Pollutant
ITR…….Ignition Timing Retard
LEA……Low Excess Air
LNB……Low NOx Burners
MR&Rs .....Monitoring, Recording, and Reporting
NESHAPS .....National Emission Standards for Hazardous Air Pollutants
NSCR…….Non-Selective Catalytic Reduction
NSPS .....New Source Performance Standards
ORL.....Owner Requested Limit
PSD.....Prevention of Significant Deterioration
PTE.....Potential to Emit
RICE, ICE .....Reciprocating Internal Combustion Engine, Internal Combustion Engine
SCR .....Selective Catalytic Reduction
SIP .....Alaska State Implementation Plan
SNCR…….Selective Non-Catalytic Reduction
ULSD .....Ultra Low Sulfur Diesel

Units and Measures

gal/hr.....gallons per hour
g/kWh .....grams per kilowatt hour
g/hp-hr .....grams per horsepower hour
hr/day.....hours per day
hr/yr .....hours per year
hp.....horsepower
lb/hr .....pounds per hour
lb/MMBtu.....pounds per million British thermal units
lb/1000 gal.....pounds per 1,000 gallons
kW .....kilowatts
MMBtu/hr.....million British thermal units per hour
MMscf/hr.....million standard cubic feet per hour
ppmv.....parts per million by volume
tpy.....tons per year

Pollutants

CO .....Carbon Monoxide
HAP.....Hazardous Air Pollutant
NOx .....Oxides of Nitrogen
SO_2 .....Sulfur Dioxide
PM-2.5.....Particulate Matter with an aerodynamic diameter not exceeding 2.5 microns
PM-10.....Particulate Matter with an aerodynamic diameter not exceeding 10 microns

1. INTRODUCTION

The North Pole Power Plant (North Pole) is an electric generating facility that combusts distillate fuel in combustion turbines to provide power to the Golden Valley Electric Association (GVEA) grid. The power plant contains two fuel oil-fired simple cycle gas combustion turbines, two fuel oil-fired combined cycle gas combustion turbines, one fuel oil-fired emergency generator, and two propane fired boilers.

In a letter dated April 24, 2015, the Alaska Department of Environmental Conservation (Department) requested the stationary sources expected to be major stationary sources in the particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers (PM-2.5) serious nonattainment area perform a voluntary Best Available Control Technology (BACT) review in support of the state agency's required SIP submittal once the nonattainment area is re-classified as a Serious PM-2.5 nonattainment area. The designation of the area as "Serious" with regard to nonattainment of the 2006 24-hour PM-2.5 ambient air quality standards was published in Federal Register Vol. 82, No. 89, May 10, 2017, pages 21703-21706, with an effective date of June 9, 2017. [1]

This report addresses the significant emission units (EUs) listed in the North Pole Power Plant's operating permit AQ0110TVP03. This report provides the Department's review of the BACT analysis for oxides of nitrogen (NOx) and sulfur dioxide (SO_2) emissions, which are precursor pollutants that can form PM-2.5 in the atmosphere post combustion.

The following sections review GVEA's BACT analysis provided for the North Pole Power Plant for technical accuracy and adherence to accepted engineering cost estimation practices.

2. BACT EVALUATION

A BACT analysis is an evaluation of all available control options for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts. 40 CFR 52.21(b)(12) defines BACT as a site-specific determination on a case-by-case basis. The Department's goal is to: identify BACT for the permanent emission units (EUs) at the GVEA North Pole Power Plant that emit NOx, PM-2.5, and SO_2, establish emission limits which represent BACT, and assess the level of monitoring, recordkeeping, and reporting (MR&R) necessary to ensure GVEA applies BACT for the EUs. The Department based the BACT review on the five-step top-down approach set forth in Federal Register Volume 61, Number 142, July 23, 1996 (Environmental Protection Agency). Table A presents the EUs subject to BACT review.

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)

Table A: Emission Units Subject to BACT Review

EU	EU Name	Description of EU	Rating/Size	Installation Date
1	GT#1	GE Frame 7, Series 7001, Fuel Oil-Fired Model BR Regenerative Simple Cycle Gas Turbine	672 MMBtu/hr (60.5 MW)	1976
2	GT#2	GE Frame 7, Series 7001, Fuel Oil-Fired Model BR Regenerative Simple Cycle Gas Turbine	672 MMBtu/hr (60.5 MW)	1977
5	GT#3	GE LM6000PC Combined Cycle Gas Turbine, Fuel 0-GT (naphtha/LSR fuel) Fired (with water injection for NOx control and CO oxidation catalyst)	455 MMBtu/hr (Higher Heating Value) 43 MW (nominal)	2005
6	GT#4	GE LM6000PC Combined Cycle Gas Turbine, Fuel 0-GT (naphtha/LSR fuel) Fired (with water injection for NOx control and CO oxidation catalyst)	455 MMBtu/hr (Higher Heating Value) 43 MW (nominal)	Est. 2015
7	Emergency Generator	IC Engine, Fuel-Oil Fired	400 kW	2005
11	Propane-Fired Boiler	Bryan Steam RV500 Heater, Gas Fuel-Fired	5.0 MMBtu/hr	2005
12	Propane-Fired Boiler	Bryan Steam RV500 Heater, Gas Fuel-Fired	5.0 MMBtu/hr	2005

GVEA did not include BACT analyses for EUs 3 and 4. These emission units are fuel storage tanks and do not have NOx, PM-2.5, or SO_2 emissions.

Five-Step BACT Determinations

The following sections explain the steps used to determine BACT for NOx, PM-2.5, and SO_2 for the applicable equipment.

Step 1 Identify All Potentially Available Control Technologies

The Department identifies all available control technologies for the EUs and the pollutant under consideration. This includes technologies used throughout the world or emission reductions through the application of available control techniques, changes in process design, and/or operational limitations. To assist in identifying available controls, the Department reviews available controls listed on the Reasonably Available Control Technology (RACT), BACT, and Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC). The RBLC is an EPA database where permitting agencies nationwide post imposed BACT for PSD sources. It is usually the first stop for BACT research. In addition to the RBLC search, the Department used several search engines to look for emerging and tried technologies used to control NOx, PM-2.5, and SO_2 emissions from equipment similar to those listed in Table A.

Step 2 Eliminate Technically Infeasible Control Technologies

The Department evaluates the technical feasibility of each control option based on source specific factors in relation to each EU subject to BACT. Based on sound documentation and

demonstration, the Department eliminates control technologies deemed technically infeasible due to physical, chemical, and engineering difficulties.

Step 3 Rank the Remaining Control Technologies by Control Effectiveness
The Department ranks the remaining control technologies in order of control effectiveness with the most effective at the top.

Step 4 Evaluate the Most Effective Controls and Document the Results as Necessary
The Department reviews the detailed information in the BACT analysis about the control efficiency, emission rate, emission reduction, cost, environmental, and energy impacts for each option to decide the final level of control. The analysis must present an objective evaluation of both the beneficial and adverse energy, environmental, and economic impacts. A proposal to use the most effective option does not need to provide the detailed information for the less effective options. If cost is not an issue, a cost analysis is not required. Cost effectiveness for a control option is defined as the total net annualized cost of control divided by the tons of pollutant removed per year. Annualized cost includes annualized equipment purchase, erection, electrical, piping, insulation, painting, site preparation, buildings, supervision, transportation, operation, maintenance, replacement parts, overhead, raw materials, utilities, engineering, start-up costs, financing costs, and other contingencies related to the control option. Sections 3, 4, and 5 present the Department's BACT Determinations for NOx, PM-2.5, and SO_2.

Step 5 Select BACT
The Department selects the most effective control option not eliminated in Step 4 as BACT for the pollutant and EU under review. The Department lists the final BACT requirements determined for each EU in this step. A project may achieve emission reductions through the application of available technologies, changes in process design, and/or operational limitations. The Department reviewed GVEA's BACT analysis and made BACT determinations for NOx, PM-2.5, and SO_2 for the North Pole Power Plant. These BACT determinations are based on the information submitted by GVEA in their analysis, information from vendors, suppliers, sub-contractors, RBLC, and an exhaustive internet search.

3. BACT DETERMINATION FOR NOx

The NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC is planning to submit with the Serious SIP a final precursor demonstration as justification not to require NOx controls. Please see the precursor demonstration for NOx posted at http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip-development. The PM2.5 NAAQS Final SIP Requirements Rule states if the state determines through a precursor demonstration that controls for a precursor gas are not needed for attaining the standard, then the controls identified as BACT/BACM or Most Stringent Measure for the precursor gas are not required to be implemented.[2] Final approval of the precursor demonstration is at the time of the Serious SIP approval.

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf

The North Pole Power Plant has two existing 672 MMBtu/hr GE Frame 7, Series 7001 turbines that burn fuel oil, two 455 MMBtu/hr GE LM6000PC gas turbines, one emergency diesel-fired internal combustion engine, and two Bryan Steam RV500 propane heaters subject to BACT. The Department reviewed the control technologies GVEA identified in their analysis and determined NOx BACT for the EUs listed in Table A. The Department based its NOx assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by Golden Valley Electric Association (GVEA) for the North Pole Power Plant and Zehnder Facility, Aurora Energy, LLC (Aurora) for the Chena Power Plant, U.S. Army Corps of Engineers (US Army) for Fort Wainwright, and the University of Alaska Fairbanks (UAF) for the Fairbanks Campus Power Plant.

3.1 NOx BACT for the Fuel Oil-Fired Simple Cycle Gas Turbines (EUs 1 and 2)

Possible NOx emission control technologies for the fuel oil-fired simple cycle turbine were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.110 for Liquid Fuel-Fired Simple Cycle Gas Turbines (rated at 25 MW or more). The search results for simple cycle gas turbines are summarized in Table 3-1.

Table 3-1. RBLC Summary of NOx Controls for Fuel Oil-Fired Simple Cycle Gas Turbines

Control Technology	Number of Determinations	Emission Limits (ppmv)
Selective Catalytic Reduction	2	7
Low NOx Burners	12	5 – 15
Good Combustion Practices	3	15

RBLC Review

A review of similar units in the RBLC indicates selective catalytic reduction, low NOx burners, and good combustion practices are the principle NOx control technologies installed on fuel oil-fired simple cycle gas turbines. The lowest NOx emission rate listed in the RLBC is 5 parts per million by volume (ppmv).

Step 1 - Identification of NOx Technology for the Simple Cycle Gas Turbines

From Research, the Department identified the following technologies as available for control of NOx emissions from fuel oil-fired simple cycle turbines rated at 25 MW or more:

(a) Selective Catalytic Reduction (SCR)

SCR is a post-combustion gas treatment technique for reducing nitric oxide (NO) and nitrogen dioxide (NO_2) in the turbine exhaust stream to molecular nitrogen (N_2), water, and oxygen (O_2). In the SCR process, aqueous or anhydrous ammonia (NH_3) is injected into the flue gas upstream of a catalyst bed. The catalyst lowers the activation energy of the NOx decomposition reaction. NOx and NH_3 combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental N_2 and water. Depending on the overall NH_3-to-NOx ratio, removal efficiencies are generally 80 to 90 percent. Challenges associated with using SCR on fuel oil-fired simple cycle gas turbines include a narrow window of acceptable inlet and exhaust temperatures (500°F to 800°F), emission of NH_3 into the atmosphere (NH_3 slip) caused by non-stoichiometric reduction reaction, and disposal of depleted catalysts. The Department

considers SCR a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(b) Water Injection

Water/steam injection involves the introduction of water or steam into the combustion zone. The injected fluid provides a heat sink which absorbs some of the heat of reaction, causing a lower flame temperature. The lower flame temperature results in lower thermal NOx formation. Both steam and water injections are capable of obtaining the same level of control. The process requires approximately 0.8 to 1.0 pound of water or steam per pound of fuel burned. The main technical consideration is the required purity of the water or steam, which is required to protect the equipment from dissolved solids. Obtaining water or steam of sufficient purity requires the installation of rigorous water treatment and deionization systems. Water/steam injection is a proven technology for NOx emissions reduction from turbines. However, the arctic environment presents significant challenges to water/steam injection due to cost of water treatment, freezing potential due to extreme cold ambient temperatures, and increased maintenance problems due to accelerated wear in the hot sections of the turbines. Moreover, the vendor of the turbines does not recommend using water/steam injection to control NO_x emissions from the turbines because of the extra maintenance problems. The Department considers water/steam injection a technically feasible control technology for the fuel-oil simple cycle gas turbines.

(c) Dry Low NOx (DLN)

Two-stage lean/lean combustors are essentially fuel-staged, premixed combustors in which each stage burns lean. The two-stage lean/lean combustor allows the turbine to operate with an extremely lean mixture while ensuring a stable flame. A small stoichiometric pilot flame ignites the premixed gas and provides flame stability. The NOx emissions associated with the high temperature pilot flame are insignificant. Low NOx emission levels are achieved by this combustor design through cooler flame temperatures associated with lean combustion and avoidance of localized "hot spots" by premixing the fuel and air. DLN is designed for natural gas-fired or dual-fuel fired units and is not effective in controlling NOx emissions from fuel oil-fired units. The Department does not consider DLN a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(d) Limited Operation

Limiting the operation of emission units reduces the potential to emit for those units. EU 1 currently operates under a combined owner requested limit (ORL) with EUs 5 and 6 to restrict the combined NOx emissions from these three units to no more than 1,600 tons per 12 month rolling period. EU 2 also operated under an ORL to restrict operation to no more than 7,992 hours per 12 month rolling period. The Department considers limited operation a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(e) Good Combustion Practices (GCPs)
GCPs typically include the following elements:

1. Sufficient residence time to complete combustion;
2. Providing and maintaining proper air/fuel ratio;
3. High temperatures and low oxygen levels in the primary combustion zone;
4. High enough overall excess oxygen levels to complete combustion and maximize thermal efficiency.

Combustion efficiency is dependent on the gas residence time, the combustion temperature, and the amount of mixing in the combustion zone. GCPs are accomplished primarily through combustion chamber design as it relates to residence time, combustion temperature, air-to-fuel mixing, and excess oxygen levels. The Department considers GCPs a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for Gas Turbines
As explained in Step 1 of Section 3.1, the Department does not consider dry low NOx as technically feasible technology to control NO_x emissions from the fuel oil-fired simple cycle gas turbines.

Step 3 - Rank the Remaining NOx Control Technologies for the Simple Cycle Gas Turbines
The following control technologies have been identified and ranked for control of NOx emissions from the fuel oil-fired simple cycle turbines:

(a + b)	Selective Catalytic Reduction & Water Injection	(95% Control)
(a)	Selective Catalytic Reduction	(90% Control)
(b)	Water Injection	(70% Control)
(g)	Good Combustion Practices	(Less than 40% Control)
(d)	Limited Operation	(0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA provided an economic analysis of the control technologies available for the fuel oil-fired simple cycle turbines to demonstrate that the use of water injection with SCR, SCR, or water injection in conjunction with limited operation is not economically feasible on these units. A summary of the analysis for EU 1 is shown in Table 3-2, and the summary of the analysis for EU 2 is shown in Table 3-3:

Table 3-2. GVEA Economic Analysis for Technically Feasible NOx Controls (EU 1)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR and Water Injection	1,600	1,440	$31,262,640	$9,214,910	$6,872
SCR	1,600	1,630	$26,213,360	$5,569,212	$4,597
Water Injection	1,600	1,168	$4,600,000	$3,610,916	$4,009
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

Table 3-3. GVEA Economic Analysis for Technically Feasible NOx Controls (EU 2)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR and Water Injection	2,363	2,127	$31,262,640	$3,249,764	$4,221
SCR	2,363	2,009	$26,213,360	$825,940	$2,791
Water Injection	2,363	1,725	$4,600,000	$2,503,774	$1,952
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

GVEA contends that the economic analysis indicates the level of NOx reduction does not justify the use of SCR, water injection, or SCR and water injection for the fuel oil-fired simple cycle gas turbines based on the excessive cost per ton of NOx removed per year.

GVEA proposes the following as BACT for NOx emissions from the fuel oil-fired simple cycle gas turbines:

(a) NOx emissions from the operation of the fuel oil-fired simple cycle gas turbines will be controlled with good combustion practices; and

(b) NOx emissions from the fuel oil-fired simple cycle gas turbines will not exceed 0.88 lb/MMBtu over a 4-hour averaging period.

Department Evaluation of BACT for NOx Emissions from the Simple Cycle Gas Turbines
The Department revised the emissions tables to reflect the limited operation as the baseline for emissions reduction for the control devices. Additionally, the Department revised the NOx removal efficiency to 95%, 90%, and 70% for SCR with water injection, SCR, and water injection respectively, the interest rate was revised to 5.5% (current bank prime interest rate), the equipment life was revised to 20 years. The PTE for EU 2 was revised based on the most recent source test data which showed a NOx emission rate of 1.39 lb/MMBtu, as opposed to the AP-42 emission factor of 0.88 lb/MMBtu. A summary of the analyses is shown below:

Table 3-4. Department Economic Analysis for Technically Feasible NOx Controls (EU 1)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR and Water Injection	1,600	1,520	$31,262,640	$7,388,635	$4,861
SCR	1,600	1,440	$26,213,360	$4,050,059	$2,813
Water Injection	1,600	1,120	$4,600,000	$3,340,904	$2,983
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

Table 3-5. Department Economic Analysis for Technically Feasible NOx Controls (EU 2)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR and Water Injection	3,733	3,546	$31,262,640	$7,150,274	$2,016
SCR	3,733	3,360	$26,213,360	$4,140,269	$1,232
Water Injection	3,733	2,613	$4,600,000	$3,097,881	$1,186
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

The Department's economic analysis indicates the level of NOx reduction justifies the use of SCR and water injection as BACT for the fuel oil-fired simple cycle gas combustion turbines located in the Serious PM-2.5 nonattainment area.

Step 5 - Selection of NOx BACT for the Simple Cycle Gas Turbines

The Department's finding is that BACT for NOx emissions from the simple cycle gas-fired combustion turbines is as follows:

(a) NOx emissions from EUs 1 and 2 shall be controlled by operating and maintaining selective catalytic reduction and water injection at all times the units are in operation;

(b) NOx emissions from EU 1 shall not exceed 0.044 lb/MMBtu averaged over a 3-hour period;

(c) NOx emissions from EU 2 shall not exceed 0.070 lb/MMBtu averaged over a 3-hour period; and

(d) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation.

Table 3-6 lists the proposed NOx BACT determination for this facility along with those for other fuel oil-fired simple cycle gas turbines located in the Serious PM-2.5 nonattainment area.

Table 3-6. Comparison of NOx BACT for Simple-Cycle Gas Turbines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
North Pole	2 Simple Cycle Combustion Gas Turbines	1,344 MMBtu/hr	0.044 – 0.070 lb/MMBtu	Selective Catalytic Reduction Water Injection
Zehnder	2 Simple Cycle Combustion Gas Turbines	536 MMBtu/hr	0.044 lb/MMBtu	Selective Catalytic Reduction Water Injection

3.2 NOx BACT for the Fuel Oil-Fired Combined Cycle Gas Turbines (EUs 5 and 6)

Possible NOx emission control technologies for fuel oil-fired combined cycle gas turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.290, Combined Cycle Liquid Fuel-Fired Gas Turbines (rated at 25 MW or more). The search results for combined cycle gas turbines are summarized in Table 3-7.

Table 3-7. RBLC Summary of NOx Controls for Combined Cycle Gas Turbines

Control Technology	Number of Determinations	Emission Limits
Selective Catalytic Reduction	8	2 – 5 ppmv
Low NOx Burner	8	0.023 - 0.14 (g/hp-hr)
Good Combustion Practices	1	0.01 (g/hp-hr)
No Control Specified	2	0.070 - 0.12 (g/hp-hr)

RBLC Review
A review of similar units in the RBLC indicates selective catalytic reduction, low-NOx burners, and good combustion practices are the principle NOx control technologies installed on fuel oil-fired combined cycle gas turbines. The lowest NOx emission rate listed in the RBLC is 0.01 g/hp-hr:

Step 1 - Identification of NOx Control Technology for the Combined Cycle Gas Turbines
From research, the Department identified the following technologies as available for control of NOx emissions from fuel oil-fired combined cycle gas turbines rated at 25 MW or more:

(a) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle turbines and will not be repeated here. The Department considers SCR a technically feasible control technology for the fuel oil-fired combined cycle gas turbines.

(b) Water Injection
The theory of water injection was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle turbines and will not be repeated here. EU 5 currently operates with water injection for NOx emissions controls and EU 6 will also utilize water injection for NOx control when it is installed. The Department considers water injection a feasible control technology for the fuel oil-fired combined cycle gas turbines.

(c) Dry Low NOx
The theory of DLN was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle turbines and will not be repeated here. DLN is designed for natural gas-fired or dual-fuel fired units and is not effective in controlling NOx emissions from fuel oil-fired units. The Department does not consider DLN to be a technically feasible control technology for the fuel oil-fired combined cycle gas turbines.

(d) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. EUs 5 and 6 currently operate under a combined ORL with EU 1 to restrict the combined NOx emissions from these three units to no more than 1,600 tons per 12 month rolling period. The Department considers limited operation a technically feasible control technology for the fuel oil-fired combined cycle gas turbines.

(f) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of NOx emissions. The Department considers GCPs a technically feasible control technology for the fuel oil-fired combined cycle gas turbines.

Step 2 - Eliminate Technically Infeasible NOx Controls for Combined Cycle Gas Turbines
As explained in Step 1 of Section 3.1, the Department does not consider DLN a technically feasible technology to control NO_x emissions from fuel oil-fired combined cycle gas turbines.

Step 3 - Rank the Remaining NOx Control Technologies for Combined Cycle Gas Turbines
The following control technologies have been identified and ranked for control of NOx from the fuel oil-fired combined cycle gas turbines:

(a)	Selective Catalytic Reduction	(90% Control)
(g)	Good Combustion Practices	(Less than 40% Control)
(b)	Water Injection	(0% Control)
(d)	Limited Operation	(0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA provided an economic analysis of the installation of SCR on the combined cycle gas turbines to demonstrate that the use of SCR in conjunction with water injection and limited operation is not economically feasible on these units. A summary of the analysis is shown below:

Table 3-8. GVEA Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
SCR	478.8 (per unit)	303 (per unit)	$8,860,032	$2,204,632	$7,278
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

GVEA contends that the economic analysis indicates the level of NOx reduction does not justify the use of SCR for the fuel oil-fired combined cycle gas turbines based on the excessive cost per ton of NOx removed per year.

GVEA proposes the following as BACT for the fuel oil-fired combined cycle gas turbines:

(a) NOx emissions from the fuel oil-fired combined cycle gas turbines shall be controlled with water injection;

(b) NOx emissions from the fuel oil-fired combined cycle gas turbines shall not exceed 0.24 lb/MMBtu[3] per 4-hour averaging period; and

(c) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation.

Department Evaluation of BACT for NOx Emissions from the Combined Cycle Gas Turbines
The Department revised the cost analysis provided by GVEA for the installation of SCR in conjunction with the existing water injection to reflect limited operation and water injection as the baseline for emissions reduction for the control devices. Additionally, the Department revised the NOx removal efficiency to 90% for SCR combined with the existing Water Injection, an interest rate of 5.5% (current bank prime interest rate), and the equipment life was revised to 20 years. A summary of the analysis is shown below:

Table 3-9. Department Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
SCR	478.8 (per unit)	430 (per unit)	$8,860,032	$1,697,020	$3,942
Capital Recovery Factor = 0.094 (7% interest rate for a 20 year equipment life)					

The Department's economic analysis indicates that the level of NOx reduction justifies the installation of SCR for the combined cycle gas combustion turbines located in the Serious PM-2.5 nonattainment area.

Step 5 - Selection of NOx BACT for the Combined Cycle Gas Turbines
The Department's finding is that the BACT for NOx emissions from the fuel oil-fired combined cycle gas turbines is as follows:

[3] AP-42 Table 3.1-1 for water-steam injection from a distillate oil fired turbine.

(a) NOx emissions from EUs 5 and 6 shall be controlled by operating and maintaining selective catalytic reduction in conjunction with water injection at all times the units are in operation;

(b) NOx emissions from EUs 5 and 6 shall not exceed 0.024 lb/MMBtu over a 3-hour averaging period; and

(c) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation.

3.3 NOx BACT for the Large Diesel-Fired Engine (EU 7)

Possible NOx emission control technologies for large engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.100 to 17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 3-11.

Table 3-11. RBLC Summary of NOx Controls for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Selective Catalytic Reduction	3	0.5 - 0.7
Other Add-On Control	1	1.0
Federal Emission Standards	13	3.0 - 6.9
Good Combustion Practices	31	3.0 - 13.5
No Control Specified	60	2.8 - 14.1

RBLC Review
A review of similar units in the RBLC indicates selective catalytic reduction, good combustion practices, and compliance with federal emission standards are the principle NOx control technologies installed on large diesel-fired engines. The lowest NOx emission rate listed in the RBLC is 0.5 g/hp-hr.

Step 1 - Identification of NOx Control Technology for the Large Diesel-Fired Engine
From research, the Department identified the following technologies as available for control of NOx from large diesel-fired engines rated at 500 horsepower or greater:

(a) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle turbines and will not be repeated here. The Department considers SCR a technically feasible control technology for the large diesel-fired engine.

(b) Turbocharger and Aftercooler
Turbocharger technology involves the process of compressing intake air in a turbocharger upstream of the air/fuel injection. This process boosts the power output of the engine. The air compression increases the temperature of the intake air so an aftercooler is used to reduce the intake air temperature. Reducing the intake air temperature helps lower the peak flame temperature which reduces NOx formation in the combustion chamber. EU ID 7 is currently operating with a turbocharger and aftercooler. The Department

considers turbocharger and aftercooler a technically feasible control technology for the large diesel-fired engine.

(c) Fuel Injection Timing Retard (FITR)
FITR reduces NOx emissions by the delay of the fuel injection in the engine from the time the compression chamber is at minimum volume to a time the compression chamber is expanding. Timing adjustments are relatively straightforward. The larger volume in the compression chamber produces a lower peak flame temperature. With the use of FITR the engine becomes less fuel efficient, particular matter emissions increase, and there is a limit with respect to the degree the timing may be retarded because an excessive timing delay can cause the engine to misfire. The timing retard is generally limited to no more than three degrees. Diesel engines may also produce more black smoke due to a decrease in exhaust temperature and incomplete combustion. FITR can achieve up to 50 percent NOx reduction. Due to the increase in particulate matter emissions resulting from FITR, this technology will not be carried forward.

(d) Ignition Timing Retard (ITR)
ITR lowers NOx emissions by moving the ignition event to later in the power stroke, after the piston has begun to move downward. Because the combustion chamber volume is not at a minimum, the peak flame temperature is not as high, which lowers combustion temperature and produces less thermal NOx. Use of ITR can cause an increase in fuel usage, an increase in particulate matter emissions, and engine misfiring. ITR can achieve between 20 to 30 percent NOx reduction. Due to the increase in particulate matter emissions resulting from ITR, this technology will not be carried forward.

(e) Federal Emission Standards
RBLC NOx determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 NSPS Subpart IIII, 40 C.F.R 63 Subpart ZZZZ, non-road engines (NREs), or EPA tier certifications. NSPS Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. EU 7 was manufactured prior to July 11, 2005 and has not been reconstructed since. Therefore, EU 7 is not subject to NSPS Subpart IIII. EU 7 is considered a commercial emergency engine and is therefore exempt from NESHAP Subpart ZZZZ. For these reasons federal emission standards will not be carried forward as a control technology.

(f) Limited Operation
EU 7 currently operates under an annual hour limit of no more than 52 hours per 12 month rolling period. The Department considers limited operation a technically feasible emissions control method.

(g) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of NOx emissions. The Department considers GCPs a technically feasible control technology for the large diesel-fired engine.

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Large Engine
As explained in Step 1 of Section 3.3, the Department does not consider fuel injection timing retard, ignition timing retard, and federal emission standards as technically feasible technologies to control NOx emissions from the large diesel-fired engine.

Step 3 - Rank the Remaining NOx Control Technologies for the Large Diesel-Fired Engine
The following control technologies have been identified and ranked for the control of NOx emissions from the large diesel-fired engine.

(a) Selective Catalytic Reduction (90% Control)
(g) Good Combustion Practices (Less than 40% Control)
(b) Turbocharger and Aftercooler (0% Control)
(f) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA provided an economic analysis for the installation of SCR on the large diesel-fired engine. A summary of the analysis is shown below:

Table 3-12. GVEA Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.50	0.45	$100,000	$14,238	$31,639
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

GVEA contends that the economic analysis indicates the level of NOx reduction does not justify installing SCR on the large diesel-fired engine based on the excessive cost per ton of NOx removed per year.

GVEA proposed the following as BACT for NOx emissions from the large diesel-fired engine:

(a) NOx emissions from the operation of the large diesel-fired engine shall be controlled by limiting operation to no more than 52 hours per 12 month rolling period;

(b) NOx emissions from the operation of the large diesel-fired engine shall be controlled by operating a turbocharger and aftercooler; and

(c) NOx emissions from the diesel-fired engine shall not exceed 0.031 lb/hp-hr over a 4-hour averaging period.

Department Evaluation of BACT for NOx Emissions from the Large Diesel-Fired Engine
The Department reviewed GVEA's proposal for the large diesel-fired engine and finds that SCR is an economically infeasible control technology. The Department does not agree with some of

the assumptions provided in GVEA's cost analysis that cause an overestimation of the cost effectiveness. However, since EU 7 is limited to 52 hours per year, the Department finds it unnecessary to revise the cost analysis as a decrease in 0.45 tpy of NOx from EU 7 will not be cost effective for installing SCR.

Step 5 - Selection of NOx BACT for the Large Diesel-Fired Engine

The Department's finding is that the BACT for NOx emissions from the large diesel-fired engine is as follows:

(a) NOx emissions from EU 7 shall be controlled by limiting its operation to no more than 52 hours per 12 month rolling period;

(b) NOx emissions from EU 7 shall be controlled by operating a turbocharger and aftercooler at all times the unit is operating;

(c) NOx emissions from EU 7 shall not exceed 10.9 g/hp-hr[4] over a 3-hour averaging period; and

(d) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation; and

Table 3-13 lists the proposed NOx BACT determination for this facility along those for other diesel-fired engines rated at more than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 3-13. Comparison of NOx BACT Limits for Large Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	8 Large Diesel-Fired Engines	> 500 hp	3.0 – 10.9 g/hp-hr	Limited Operation Good Combustion Practices Federal Emission Standards
UAF	Large Diesel-Fired Engine	13,266 hp	1.3 g/hp-hr	Selective Catalytic Reduction Turbocharger and Aftercooler Good Combustion Practices Limited Operation
GVEA North Pole	Large Diesel-Fired Engine	600 hp	10.9 g/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp (each)	10.9 g/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation

3.4 NOx BACT for the Propane-Fired Boilers (EUs 11 and 12)

Possible NOx emission control technologies for propane-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process

[4] Table 3.4-1 of US EPA's AP-42 Emission Factors. https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s04.pdf

code 13.310, Gas-Fired Boilers (<100 MMBtu/hr). The search results for gas-fired boilers are summarized in Table 3-14.

Table 3-14. RBLC Summary of NOx Control for Gas-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Good Combustion Practices	19	0.011 – 0.05
Low NOx Burners	41	0.01 – 0.07
Selective Catalytic Reduction	4	0.006 – 0.06
Selective Non-Catalytic Reduction	1	0.14
No Control Specified	9	0.006 – 0.036

RBLC Review
A review of similar units in the RBLC indicates good combustion practices, low NOx burners, selective catalytic reduction, and selective non-catalytic reduction are the principle NOx control technologies installed on gas-fired boilers. The lowest emission rate listed in the RBLC is 0.006 lb/MMBtu.

Step 1 - Identification of NOx Control Technology for the Propane-Fired Boilers
From research, the Department identified the following technologies as available for control of NOx emissions from the propane-fired boilers:

(a) Low NOx Burners
Using LNBs can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature. Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%. The Department considers LNBs a technically feasible control technology for the propane-fired boilers.

(b) Ultra-Low NOx Burners
Ultra-low NOx burners operate on the same principle as LNB described above, but have advanced designs for achieving higher NOx destruction efficiencies. Designs that promote superior NOx destruction efficiencies often have a higher investment cost than typical LNBs. For smaller EUs manufacturers do not offer ultra-low NOx burners because of incremental emissions reduction is not cost effective as compared to standard LNBs. Ultra-low NOx burners are not available for EUs 11 and 12. The Department does not consider the use of ultra-low NOx burners a technically feasible control technology for the propane-fired boilers.

(c) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle turbines and will not be repeated here. The RLBC indicated that no applications of SCR have been demonstrated in practice for gas-fired boilers rated at less than 25 MMBtu/hr. EUs 11 and 12 are each rated at 5 MMBtu/hr. The Department does not consider SCR to be a technically feasible control technology for the propane-fired boilers.

(d) Flue Gas Recirculation
Flue gas recirculation (FGR) involves recycling a portion of the combustion gases from the stack to the boiler combustion air intake. The combustion products are low in oxygen, and when mixed with the combustion air, lower the overall excess oxygen concentration. This process acts as a heat sink to lower the peak flame temperature as well as the residence time at peak flame temperature. These effects work together to limit thermal NOx formation. The typical NOx removal efficiency using FGR is 20-25%. The Department considers FGR to be a technically feasible control technology for the propane-fired boilers.

(e) Fuel Type
The RBLC identified the use of natural gas or propane as fuel to reduce NOx emissions, or the use of gas meeting public utility specifications. Natural gas services are not available in Fairbanks or North Pole, but propane is available and is currently fired in EUs 11 and 12. The Department considers fuel type to be a technically feasible control technology for the propane-fired boilers.

(f) Scrubber
The RBLC identified one instance of a scrubber being used for NOx emission control on a galvanizing line furnace rated at 98.7 MMBtu/hr. Galvanizing line furnaces operate at very high temperatures, more than 1,000 °F, to promote chemical reactions for the galvanizing process. EUs 11 and 12 are much smaller units, rated at 5 MMBtu/hr, and are used for comfort heating, with a working temperature of approximately 250 °F. NOx formation is known to increase with higher operating temperatures. Given the disparity in size, purpose, and operating temperature between these units, the Department does not consider a scrubber a technically feasible control technology for the propane-fired boilers.

(g) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. EUs 11 and 12 are the only sources of heat for the North Pole Power Plant. Therefore, it is not appropriate to limit the operation of these units. The Department does not consider limited operation a technically feasible control technology for the propane-fired boilers.

(h) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of NOx emissions. The Department considers GCPs a technically feasible control technology for the propane-fired boilers.

Step 2 - Eliminate Technically Infeasible NOx Technologies for the Propane-Fired Boilers
As explained in Step 1 of Section 3.5, the Department does not consider Ultra-low NOx burners, selective catalytic reduction, scrubbers, and limited operation as technically feasible technology to control NOx emissions from the propane-fired boilers.

Step 3 - Rank the Remaining NOx Control Technologies for the Propane-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from the propane-fired boilers.

(a) Low NOx Burners (80% Control)
(d) Flue Gas Recirculation (20% - 25% Control)
(f) Good Combustion Practices (Less than 40% Control)
(b) Fuel Type (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA provided an economic analysis of the installation of Low NOx Burners on the startup heater. A summary of the analysis is shown in Table 3-15:

Table 3-15. GVEA Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Low NOx Burner	3.1	2.4	$38,650	$5,503	$2,276
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

GVEA contends that the economic analysis indicates the level of NOx reduction does not justify the use of LNB or FGR for the propane-fired boilers based on the excessive cost per ton of NOx removed per year.

GVEA proposed the following as BACT for the propane-fired boilers:

(a) Burn only propane as fuel in EUs 11 and 12;

(b) NOx emissions from the operation of the propane-fired boilers shall be controlled with good combustion practices;

(c) NOx emissions from the propane-fired boilers shall not exceed 13 lb/kgal over a 4-hour averaging period; and

(d) Compliance with the emission limit will be demonstrated with records of maintenance following original equipment manufacturer recommendations for operation and maintenance and periodic measurements of O_2 balance.

Department Evaluation of BACT for NOx Emissions from the Propane-Fired Boilers
The Department revised the emissions tables to reflect an 80% control efficiency. Additionally, the interest rate was revised to 5.5% (current bank prime interest rate), and the equipment life was revised to 20 years. A summary of the analysis is shown in Table 3-16:

Table 3-16. Department Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Low NOx Burner	3.1	2.5	$38,650	$3,234	$1,304
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

The Department's economic analysis indicates the level of NOx reduction justifies the installation of low NOx burners on the propane-fired boilers located in the Serious PM-2.5 nonattainment area.

Step 5 - Selection of NOx BACT for the Propane-Fired Boilers

The Department's finding is that the BACT for NOx emissions from the propane-fired boilers is as follows:

(a) NOx emissions from EUs 11 and 12 shall be controlled by installing low NOx burners in conjunction with using propane as fuel at all times the units are in operation;

(b) NOx emissions from EUs 11 and 12 shall not exceed 0.030 lb/MMbtu[5] averaged over a 3-hour period; and

(c) Compliance with the emission rate limit will be demonstrated with records of maintenance following original equipment manufacturer recommendations for operation and maintenance and periodic measurements of O_2 balance.

Table 3-17 lists the proposed NOx BACT determination for this facility along with those for other propane-fired boilers rated at less than 100 MMBtu/hr in the Serious PM-2.5 nonattainment area.

Table 3-17. NOx BACT Limits for the Propane-Fired Boilers

Facility	Process Description	Capacity	Limitation	Control Method
GVEA North Pole	Two Small Propane-Fired Boilers	< 100 MMbtu/hr	0.030 lb/MMBtu	Propane as Fuel Low NOx Burners Good Combustion Practices

4. BACT DETERMINATION FOR PM-2.5

The Department based its PM-2.5 assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by GVEA for the North Pole Power Plant and Zehnder Facility, Aurora for the Chena Power Plant, US Army for Fort Wainwright, and UAF for the Combined Heat and Power Plant.

[5] Emission factor derived from AP-42 Table 1.5-1 for propane-fired boilers (13 lb/1,000 gal) converted to lb/MMbtu, and then assumes 80% control efficiency by installing low NOx burners.

4.1 PM-2.5 BACT for the Fuel Oil-Fired Simple Cycle Gas Turbines (EUs 1 and 2)

Possible PM-2.5 emission control technologies for the fuel oil-fired simple cycle gas turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.110 Simple Cycle Gas Turbines (rated at 25 MW or more) The search results for simple cycle gas turbines are summarized in Table 4-1.

Table 4-1. RBLC Summary of PM-2.5 Control for Simple Cycle Gas Turbines

Control Technology	Number of Determinations	Emission Limits
Good Combustion Practices	25	0.0038 – 0.0076 lb/MMBtu
Clean Fuels	12	5 – 14 lb/hr

RBLC Review
A review of similar units in the RBLC indicates restrictions on fuel sulfur contents and good combustion practices are the principle PM control technologies installed on simple cycle gas turbines. The lowest PM-2.5 emission rate listed in the RBLC is 0.0038 lb/MMBtu.

Step 1 - Identification of PM-2.5 Control Technology for the Simple Cycle Gas Turbines
From research, the Department identified the following technologies as available for control of PM-2.5 emissions from fuel oil-fired simple cycle gas turbines:

(a) Low Sulfur Fuel
Low sulfur fuel has been known to reduce particulate matter emissions. PM-2.5 emission rates for low sulfur fuel are not available and therefore a BACT emissions rate cannot be set for low sulfur fuel. The Department does not consider low sulfur fuel a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(b) Low Ash Fuel
Residual fuels and crude oil are known to contain ash forming components, while refined fuels are low ash. Fuels containing ash can cause excessive wear to equipment and foul combustion components. EUs 1 and 2 are fired exclusively on distillate fuel which is a form of refined fuel, and potential PM-2.5 emissions are based on emission factors for distillate fuel. The Department considers low ash fuel a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(c) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. Due to EUs 1 and 2 currently operating under limits, the Department considers limited operation as a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of PM. The Department considers GCPs a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

Step 2 - Eliminate Technically Infeasible PM-2.5 Technologies for the Simple Cycle Gas Turbines
As explained in Step 1 of Section 4.1, the Department does not consider low sulfur fuel as a technically feasible technology to control PM-2.5 emissions from the fuel oil-fired simple cycle gas turbines.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Simple Cycle Gas Turbines
The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 emissions from the fuel oil-fired simple cycle gas turbines:

(d) Good Combustion Practices (Less than 40% Control)
(b) Low Ash Fuel (0% Control)
(c) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA proposes the following as BACT for PM-2.5 emissions from the fuel oil-fired simple cycle gas turbines:

(a) PM-2.5 emissions from EUs 1 and 2 shall not exceed 0.012 lb/MMBtu over a 4-hour averaging period; and

(b) Maintain good combustion practices.

Step 5 - Selection of PM-2.5 BACT for the Simple Cycle Gas Turbines
The Department's finding is that BACT for PM-2.5 emissions from the fuel oil-fired simple cycle gas turbine is as follows:

(a) PM-2.5 emissions from EUs 1 and 2 shall be controlled by combusting only low ash fuel;

(b) Maintain good combustion practices at all times of operation by following the manufacturer's operation and maintenance procedures; and

(c) PM-2.5 emissions from EUs 1 & 2 shall not exceed 0.012 lb/MMBtu[6] over a 3-hour averaging period.

Table 4-2 lists the proposed PM-2.5 BACT determination for this facility along with those for other fuel oil-fired simple cycle gas turbines located in the Serious PM-2.5 nonattainment area.

Table 4-2. Comparison of PM-2.5 BACT for Simple Cycle Gas Turbines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
GVEA – North Pole	Two Fuel Oil-Fired Simple Cycle Gas Turbines	1,344 MMBtu/hr	0.012 lb/MMBtu[6] (3-hour averaging period)	Good Combustion Practices
GVEA – Zehnder	Two Fuel Oil-Fired Simple Cycle Gas Turbines	536 MMBtu/hr	0.012 lb/MMBtu[6] (3-hour averaging period)	Good Combustion Practices

[6] Table 3.1-2a of US EPA's AP-42 Emission Factors. https://www3.epa.gov/ttnchie1/ap42/ch03/final/c03s01.pdf

4.2 PM-2.5 BACT for the Combined Cycle Gas Turbines (EUs 5 and 6)

Possible PM-2.5 emission control technologies for the fuel oil-fired combined cycle gas turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.210, Liquid Fuel-Fired Combined Cycle Combustion Turbines (rated at 25 MW or more). The search results for combined cycle gas turbines are summarized in Table 4-3.

Table 4-3. RBLC Summary for PM-2.5 Control for the Combined Cycle Gas Turbines

Control Technology	Number of Determinations	Emission Limits
Good Combustion Practices	9	4 – 19.35 lb/hr
Clean Fuels	12	4.7 – 60.6 lb/hr

RBLC Review
A review of similar units in the RBLC indicates good combustion practices and clean fuels are the principle PM-2.5 control technologies installed on fuel oil-fired combined cycle gas turbines. The lowest NOx emission rate listed in the RBLC is 4 lb/hr.

Step 1 - Identification of PM-2.5 Control Technology for the Combined Cycle Gas Turbines
From research, the Department identified the following technologies as available for control of PM-2.5 emissions from fuel oil-fired combined cycle gas turbines rated at 25 MW or more:

(a) Low Sulfur Fuel
Low sulfur fuel has been known to reduce particulate matter emissions. The Department considers low sulfur fuel a technically feasible control technology for the fuel oil-fired combined cycle gas turbines.

(b) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. EUs 5 and 6 currently operate under a combined ORL with EU 1 to restrict the combined NOx emissions from these three units to no more than 1,600 tons per 12 month rolling period. The Department considers limited operation a technically feasible control technology for the fuel oil-fired combined cycle gas turbines.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of particulate matter. The Department considers GCPs a technically feasible control technology for the fuel oil-fired combined cycle turbines.

Step 2 - Eliminate Technically Infeasible PM-2.5 Controls for the Combined Cycle Gas Turbines
As explained in Step 1 of Section 4.1, the Department does not consider low sulfur fuel as technically feasible technology to control PM-2.5 emissions from the fuel oil-fired combined cycle gas turbines.

Step 3 - Rank the Remaining PM-2.5 Controls for the Combined Cycle Gas Turbines
The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 emissions from the combined cycle gas turbines:

(c) Good Combustion Practices (Less than 40% Control)
(b) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA proposes the following as BACT for PM-2.5 emissions from the fuel oil-fired combined cycle gas turbines:

(a) PM-2.5 emissions shall not exceed 0.012 lb/MMBtu over a 4-hour averaging period; and

(b) Maintain good combustion practices.

Department Evaluation of BACT for PM-2.5 Emissions from the Combined Cycle Gas Turbines

The Department reviewed GVEA's proposal and found that in addition to maintaining good combustion practices, limited operation is also a technically feasible control technology.

Step 5 - Selection of PM-2.5 BACT for the Combined Cycle Gas Turbines
The Department's finding is that BACT for PM-2.5 emissions from the combined cycle gas turbines is as follows:

(a) PM-2.5 emissions from EUs 5 and 6 shall be limited by complying with the combined annual NOx limit listed in Operating Permit AQ0110TVP03 Condition 13;

(b) PM-2.5 emissions from EUs 5 and 6 shall not exceed 0.012 lb/MMBtu[6] over a 3-hour averaging period; and

(c) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation.

4.3 PM-2.5 BACT for the Large Diesel-Fired Engine (EU 7)

Possible PM-2.5 emission control technologies for the large diesel-fired engine were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110-17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 4-5.

Table 4-5. RBLC Summary of PM-2.5 Control for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Federal Emission Standards	12	0.03 – 0.02
Good Combustion Practices	28	0.03 – 0.24
Limited Operation	11	0.04 – 0.17
Low Sulfur Fuel	14	0.15 – 0.17
No Control Specified	14	0.02 – 0.15

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices, compliance with the federal emission standards, low ash/sulfur diesel, and limited operation are the principle PM-2.5 control technologies installed on large diesel-fired engines. The lowest PM-2.5 emission rate in the RBLC is 0.02 g/hp-hr.

Step 1 - Identification of PM-2.5 Control Technology for the Large Diesel-Fired Engine
From research, the Department identified the following technologies as available for controls of PM-2.5 emissions from diesel fired engines rated at 500 hp or greater:

(a) Diesel Particulate Filter (DPF)
DPFs are a control technology that is designed to physically filter particulate matter from the exhaust stream. Several designs exist which require cleaning and replacement of the filter media after soot has become caked onto the filter media. Regenerative filter designs are also available that burn the soot on a regular basis to regenerate the filter media. DPF can reduce PM-2.5 emissions by 85%. The Department considers DPF a technically feasible control technology for the large diesel-fired engine.

(b) Diesel Oxidation Catalyst (DOC)
DOC can reportedly reduce PM-2.5 emissions by 30% and PM emissions by 50%. A DOC is a form of "bolt on" technology that uses a chemical process to reduce pollutants in the diesel exhaust resulting in decreased concentrations. They replace mufflers on vehicles, and require no modifications. More specifically, this is a honeycomb type structure that has a large area coated with an active catalyst layer. As CO and other gaseous hydrocarbon particles travel along the catalyst, they are oxidized thus reducing pollution. The Department considers DOC a technically feasible control technology for the large diesel-fired engine.

(c) Positive Crankcase Ventilation
Positive crankcase ventilation is the process of re-introducing the combustion air into the cylinder chamber for a second chance at combustion after the air has seeped into and collected in the crankcase during the downward stroke of the piston cycle. This process allows any unburned fuel to be subject to a second combustion opportunity. Any combustion products act as a heat sink during the second pass through the piston, which will lower the temperature of combustion and reduce the thermal NOx formation. Positive crankcase ventilation is included in the design of EU 7. The Department considers positive crankcase ventilation a technically feasible control technology for the large diesel-fired engine.

(d) Low Sulfur Fuel
Low sulfur fuel has been known to reduce particulate matter emissions. The Department considers low sulfur fuel as a technically feasible control technology for the large diesel-fired engine.

(e) Low Ash Diesel
Residual fuels and crude oil are known to contain ash forming components, while refined fuels are low ash. Fuels containing ash can cause excessive wear to equipment and foul engine components. EU 7 is fired exclusively on distillate fuel which is a form of refined fuel. The potential PM-2.5 emissions are based on emission factors for distillate fuel. The Department considers low ash diesel a technically feasible control technology for the large diesel-fired engine.

(f) Federal Emission Standards
The theory behind the federal emission standards for EU 7 was discussed in detail in the NOx BACT for the large diesel-fired engine and will not be repeated here. Due to EU 7 not being subject to either 40 C.F.R. 60 Subpart IIII or 40 C.F.R. 63 Subpart ZZZZ the Department does not consider federal emission standards a technically feasible control technology for the large diesel-fired engine.

(g) Limited Operation
The theory behind limited operation for EU 7 was discussed in detail in the NOx BACT for the large diesel-fired engine and will not be repeated here. Due to EU 7 currently operating under an annual hour limit of no more than 52 hours per 12 month rolling period, the Department considers limited operation a technically feasible control technology for the large diesel-fired engine.

(h) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of NOx emissions. The Department considers GCPs a technically feasible control technology for the large diesel-fired engine.

Step 2 - Eliminate Technically Infeasible PM-2.5 Control Technologies for the Large Engine
PM-2.5 emission rates for low sulfur fuel are not available and therefore a BACT emissions rate cannot be set for low sulfur fuel. Low sulfur fuel is not a technically feasible control technology. As explained in Step 1 of Section 4.3, federal emission standards are not technically feasible control technology for control of PM-2.5 emissions from the large diesel-fired engine.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Large Diesel-Fired Engine
The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 emissions from the large diesel-fired engines:

(a)	Diesel Particulate Filters	(85% Control)
(g)	Good Combustion Practices	(Less than 40% Control)
(b)	Positive Crankcase Ventilation	(0% Control)
(d)	Low Ash Diesel	(0% Control)
(f)	Limited Operation	(0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

GVEA Proposal

GVEA provided an economic analysis for the installation of diesel particulate filter. A summary of the analysis for is shown below:

Table 4-6. GVEA Economic Analysis for Technically Feasible PM-2.5 Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
Diesel Particulate Filter	0.035	0.03	$30,229	$4,304	$143,008
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

GVEA contends that the economic analysis indicates that the level of PM-2.5 reduction does not justify the use of a diesel particulate filter based on the excessive cost per ton of PM-2.5 removed per year.

GVEA proposes the following as BACT for PM-2.5 emissions from the large diesel-fired engine:

(a) PM-2.5 emissions from EU 7 shall be controlled by operating with positive crankcase ventilation;

(b) Maintaining good combustion practices;

(c) PM-2.5 emissions from EU 7 shall be controlled by limiting operation to no more than 52 hours per 12 month rolling period; and

(d) PM-2.5 emissions from EU 7 shall not exceed 0.0022 lb/hp-hr[7] over a 4-hour averaging period.

Department Evaluation of BACT for PM-2.5 Emissions from the Large Diesel-Fired Engine

The Department reviewed GVEA's proposal for the large diesel-fired engine and finds that installing a diesel particulate filter is an economically infeasible control technology. The Department does not agree with some of the assumptions provided in GVEA's cost analysis that cause an overestimation of the cost effectiveness. However, since EU 7 is limited to 52 hours per year, the Department finds it unnecessary to revise the cost analysis as a decrease in 0.03 tpy of PM-2.5 from EU 7 will not be cost effective for installing a diesel particulate filter.

Step 5 - Selection of PM-2.5 BACT for the Large Diesel-fired Engine

The Department's finding is that the BACT for PM-2.5 emissions from the large diesel-fired engine is as follows:

(a) PM-2.5 emissions from EU 7 shall be controlled by operating with positive crankcase ventilation;

(b) PM-2.5 emissions from EU 7 shall be controlled by limiting operation to no more than 52 hours per 12 month rolling period;

[7] Emissions Inventory Data: http://dec.alaska.gov/Applications/Air/airtoolsweb/PointSourceEmissionInventory/XmlInventory?reportingYear=2017&organizationKey=10&facilityKey=110&addEmissionUnits=0&addReleasePoints=0

(c) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation; and

(d) PM-2.5 emissions from EU 7 shall not exceed 0.32 g/hp-hr[8] over a 3-hour averaging period.

Table 4-7 lists the proposed PM-2.5 BACT determination for the facility along with those for other diesel-fired engines rated at more than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 4-7. Comparison of PM-2.5 BACT for the Large Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	Large Diesel-Fired Engine	13,266 hp	0.32 g/hp-hr	Positive Crankcase Ventilation Limited Operation Good Combustion Practices
Fort Wainwright	8 Large Diesel-Fired Engines	> 500 hp	0.15 – 10.9 g/hp-hr	Limited Operation Ultra-Low Sulfur Diesel Federal Emission Standards Good Combustion Practices
GVEA North Pole	Large Diesel-Fired Engine	600 hp	0.32 g/hp-hr	Positive Crankcase Ventilation Good Combustion Practices
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp (each)	0.32 g/hp-hr	Limited Operation Good Combustion Practices

4.5 PM-2.5 BACT for the Propane-Fired Boilers (EUs 11 and 12)

Possible PM-2.5 emission control technologies for the propane-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.310, Gas-Fired Boilers (<100 MMBtu/hr). The search results for gas-fired boilers are summarized in Table 4-8.

Table 4-8. RBLC Summary of PM-2.5 Control for Gas-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Good Combustion Practices	49	0.0019 – 0.0095
Electrostatic Precipitator	3	0.015 – 0.032

RBLC Review

A review of similar units in the RBLC indicates that good combustion practices and electrostatic precipitators are the principle PM-2.5 control technology determined for propane-fired boilers. The lowest PM-2.5 emission rate listed in the RBLC is 0.0019 lb/MMBtu.

Step 1 - Identification of PM-2.5 Control Technology for the Propane-Fired Boilers

From research, the Department identified the following technologies as available for control of PM-2.5 emissions from propane-fired boilers:

[8] Table 3.4-1 of US EPA's AP-42 Emission Factors (PM). https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s04.pdf.

(a) Low Sulfur Fuel
The boilers (EUs 11 and 12) are fired using propane, which is an inherently low sulfur fuel. Condition 11 of AQ0110TVP03 limits the sulfur content of the propane combusted in the boilers to 120 ppmv. Recent tests indicate that the propane fired in the boilers contains less than 3 ppm H_2S as determined by the length-of-stain methodology. The Department considers low sulfur fuel a technically feasible control technology for the propane-fired boilers.

(b) Flue Gas Recirculation
The theory behind FGR was discussed in detail in the NOx BACT for the propane-fired boilers and will not be repeated here. The Department considers FGR a technically feasible control technology for the propane-fired boilers.

(c) Baghouse
Baghouses are comprised of an array of filter bags contained in housing. Air passes through the filter media from the "dirty" to the "clean" side of the bag. These devices undergo periodic bag cleaning based on the build-up of filtered material on the bag as measured by pressure drop across the device. The cleaning cycle is set to allow operation within a range of design pressure drop. Baghouses are characterized by the type of cleaning cycle - mechanical-shaker, pulse-jet, and reverse-air. Fabric filter systems have control efficiencies of 95% to 99.9% [9] and are generally specified to meet a discharge concentration of filterable particulate (e.g., 0.01 grains per dry standard cubic feet). The only entry for a baghouse in the RBLC was for a 30 MMBtu/hr furnace for glass melting at an insulation manufacturing facility and the unit is subject to the PM emission standards under 40 C.F.R. 63 Subpart NNN. EUs 11 and 12 are much smaller units at 5 MMBtu/hr, are used for providing space heating, and have a much lower working temperature. Due to the differences in size, purpose, and operating temperatures, the Department does not consider a baghouse a technically feasible control technology for the propane-fired boilers.

(d) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. EUs 11 and 12 are the only sources of heat for the North Pole Power Plant. Therefore, it is not appropriate to limit the operation of these units. The Department does not consider the use of limited operation a technically feasible control technology for the propane-fired boilers.

(e) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle gas turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of PM-2.5 emissions. The Department considers GCPs a technically feasible control technology for the propane-fired boiler.

[9] https://www3.epa.gov/ttn/catc/dir1/ff-shaker.pdf
https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf
https://www3.epa.gov/ttn/catc/dir1/ff-revar.pdf

Step 2 - Eliminate Technically Infeasible PM-2.5 technologies for the Propane-Fired Boilers
As explained in Step 1 of Section 4.5, the Department does not consider a baghouse and limited operation as technically feasible PM-2.5 control technologies. Flue gas recirculation is not recommended by the vendor as a control technology for EUs 11 and 12, and therefore is not considered a technically feasible control technology.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Propane-Fired Boilers
GVEA has accepted the only technically feasible control technology for EUs 11 and 12. Therefore, ranking is not required.

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA proposes the following as BACT for the propane-fired boilers:

(a) Burn low sulfur fuel in EUs 11 and 12;

(b) PM-2.5 emissions from EUs 11 and 12 shall not exceed 0.7 lb/1000 gal over a 4-hour averaging period; and

(c) Compliance with the emission limit will be demonstrated with records of maintenance following original equipment manufacturer recommendations for operation and maintenance and periodic measurements of O_2 balance.

Department Evaluation of BACT for PM-2.5 Emissions from the Propane-Fired Boilers
The Department reviewed GVEA's proposal for EUs 11 and 12 and finds that an emission rate achievable with good combustion practices is also BACT for the propane-fired boilers.

Step 5 - Selection of PM-2.5 BACT for the Propane-Fired Boilers
The Department's finding is that BACT for PM-2.5 emissions from the propane-fired boilers is as follows:

(a) Burn only propane as fuel in EUs 11 and 12;

(b) PM-2.5 emissions from the operation of the propane-fired boilers shall be controlled with good combustion practices;

(c) PM-2.5 emissions from EUs 11 and 12 shall not exceed 0.008 lb/MMBtu[10] over a 3-hour averaging period; and

(d) Compliance with the emission limit will be demonstrated with records of maintenance following original equipment manufacturer recommendations for operation and maintenance and periodic measurements of O_2 balance.

5. BACT DETERMINATION FOR SO_2

The Department based its SO_2 assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by GVEA for the North Pole Power Plant and Zehnder Facility, Aurora for the Chena Power Plant, US Army for Fort Wainwright, and UAF for the Combined Heat and Power Plant.

[10] Emission factor derived from AP-42 Table 1.5-1 for propane-fired boilers (0.7 lb/1,000 gal) converted to lb/MMbtu.

5.1 SO_2 BACT for the Fuel Oil-Fired Simple Cycle Gas Turbines (EUs 1 and 2)

Possible SO_2 emission control technologies for the fuel oil-fired simple cycle gas turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.190 for Simple Cycle Gas Turbines (rated at 25 MW or more) The search results for simple cycle gas turbines are summarized in Table 5-1.

Table 5-1. RBLC Summary of SO_2 Controls for Fuel Oil-Fired Simple Cycle Gas Turbines

Control Technology	Number of Determinations	Emission Limits
Ultra-Low Sulfur Diesel	7	0.0015 % S by wt.
Fuel Oil (0.05 % S by wt.)	2	0.0026 – 0.055 lb/MMBtu
Good Combustion Practices	3	0.6 lb/hr

RBLC Review
A review of similar units in the RBLC indicates that limiting the sulfur content of fuel and good combustion practices are the principle SO_2 control technologies determined as BACT for fuel oil-fired simple cycle gas turbines. The lowest SO_2 emission rate listed in the RBLC is combustion of ULSD at 0.0015 % S by wt.

Step 1 - Identification of SO_2 Control Technology for the Simple Cycle Gas Turbines
From research, the Department identified the following technologies as available for control of SO_2 emissions from fuel oil-fired simple cycle gas turbines rated at 25 MW or greater:

(a) Ultra Low Sulfur Diesel (ULSD)
ULSD has a fuel sulfur content of 0.0015 percent sulfur by weight or less. Using ULSD would reduce SO_2 emissions because the fuel oil-fired simple cycle gas turbines are combusting standard diesel that has a sulfur content of up to 0.5 percent sulfur by weight. Switching to ULSD could reach a great than 99 percent decrease in SO_2 emissions from the fuel oil-fired simple cycle gas turbines. The Department considers ULSD a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(b) Low Sulfur Fuel
Low sulfur fuel has a fuel sulfur content of 0.05 percent sulfur by weight. Using low sulfur fuel would reduce SO_2 emissions because the fuel oil-fired simple cycle gas turbines are combusting standard diesel that has a sulfur content of up to 0.5 percent sulfur by weight. Switching to low sulfur fuel could reach a 93 percent decrease in SO_2 emissions from the fuel oil-fired simple cycle gas turbines during non-startup operation. The Department considers low sulfur diesel a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(c) Limited Operation
The theory behind limited operation for EUs 1 and 2 was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle gas turbines and will not be repeated here. Due to EUs 1 and 2 currently operating under limits, the Department considers limited operation a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle gas turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2. The Department considers GCPs a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

Step 2 - Eliminate Technically Infeasible SO_2 Technologies for the Simple Cycle Gas Turbines
All control technologies identified are technically feasible for the fuel oil-fired simple cycle gas turbines.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Simple Cycle Gas Turbines
The following control technologies have been identified and ranked for control of SO_2 from the fuel oil-fired simple cycle gas turbines:

(a) Ultra Low Sulfur Diesel (99.7% Control)
(b) Low Sulfur Diesel (93% Control)
(d) Good Combustion Practices (Less than 40% Control)
(c) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA provided an economic analysis for switching the fuel combusted in the simple cycle gas turbines to ultra-low sulfur diesel and low sulfur fuel. A summary of the analyses for each of EUs 1 and 2 is shown below:

Table 5-2. GVEA Economic Analysis for Technically Feasible SO_2 Controls for EU 1

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD (0.0015 % S wt.)	1,486.4	1,481.9	$21,750,638	$20,661,330	$13,942
Low Sulfur Fuel (0.05 % S wt.)	1,486.4	1,337.8	???	???	???
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

Table 5-3. GVEA Economic Analysis for Technically Feasible SO_2 Controls for EU 2

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD (0.0015 % S wt.)	1,356.1	1,352.0	$8,674,362	$18,978,063	$14,037
Low Sulfur Fuel (0.05 % S wt.)	1,356.1	1,220.5	???	???	???
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

GVEA contends that the economic analysis indicates the level of SO_2 reduction does not justify the fuel switch to ULSD or Low Sulfur Fuel in the simple cycle turbines based on the excessive cost per ton of SO_2 removed per year.

GVEA proposes the following as BACT for SO_2 emissions from the simple cycle gas turbines:

(a) SO_2 emissions from the fuel oil-fired simple cycle gas turbines will be controlled by complying with NOx limits for EUs 1 and 2 listed in Operating Permit AQ0110TVP03 Conditions 13 and 12, respectively;

(b) SO_2 emissions from the fuel oil-fired simple cycle gas turbines will be limited by maintain good combustion practices; and

(c) Restricting the sulfur content to 500 ppm in fuel.

Department Evaluation of BACT for SO_2 Emissions from the Simple Cycle Gas Turbines
The Department revised the cost analyses provided by GVEA for the fuel switch to ULSD in the simple cycle gas turbines using an interest rate of 5.5% (current bank prime interest rate), assuming a 20 year equipment life, and a fuel cost increase of $0.2668/gallon. Additionally, the Department reviewed the cost information provided by GVEA to appropriately evaluate the total capital investment of installing two new 1.5 million gallon ULSD storage tanks at GVEA's North Pole Power Plant. A summary of these analyses is shown in Table 5-4 and Table 5-5.

Table 5-4. Department Economic Analysis for Technically Feasible SO_2 Controls for EU 1

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD	1,486.4	1481.9	$10,875,319	$13,426,413	$9,060
Capital Recovery Factor = 0.0837 (5.5% interest rate for a 20 year equipment life)					

Table 5-5. Department Economic Analysis for Technically Feasible SO_2 Controls for EU 2

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD	1,356.1	1,352.0	$10,875,319	$12,367,225	$9,147
Capital Recovery Factor = 0.0837 (5.5% interest rate for a 20 year equipment life)					

The Department's economic analysis indicates the level of SO_2 reduction justifies the use of ULSD as BACT for the fuel oil-fired simple cycle gas turbines located in the Serious PM-2.5 nonattainment area.

Step 5 - Selection of SO_2 BACT for the Simple Cycle Gas Turbines
The Department's finding is that BACT for SO_2 emissions from the fuel oil-fired simple cycle gas turbines is as follows:

(a) SO_2 emissions from EUs 1 and 2 shall be controlled by limiting the sulfur content of fuel combusted in the turbines to no more than 0.0015 percent by weight;

(b) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation; and

(c) Compliance with the proposed fuel sulfur content limit will be demonstrated with fuel shipment receipts and/or fuel test results for sulfur content.

Table 5-6 lists the proposed SO_2 BACT determination for this facility along with those for other fuel oil-fired simple cycle gas turbines located in the Serious PM-2.5 nonattainment area.

Table 5-6. Comparison of SO_2 BACT for Simple Cycle Gas Turbines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
GVEA – North Pole	Two Fuel Oil-Fired Simple Cycle Gas Turbines	1,344 MMBtu/hr	0.0015 % S wt.	ULSD
GVEA – Zehnder	Two Fuel Oil-Fired Simple Cycle Gas Turbines	536 MMBtu/hr	0.0015 % S wt.	ULSD

5.2 SO_2 BACT for the Fuel Oil-Fired Combined Cycle Gas Turbines (EUs 5 and 6)

Possible SO_2 emission control technologies for the fuel oil-fired combined cycle gas turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.290 for Liquid Fuel-Fired Combined Cycle Gas Turbines rated at 25 MW or more. The search results for combined cycle gas turbines are summarized in Table 5-7.

Table 5-7. RBLC Summary of SO_2 Control for Oil-Fired Combined Cycle Gas Turbines

Control Technology	Number of Determinations	Emission Limits
Ultra-Low Sulfur Diesel	1	6.7 lb/hr

RBLC Review
A review of similar units in the RBLC indicates combustion of ultra-low sulfur diesel is the principle SO_2 control technology installed on fuel oil-fired combined cycle gas turbines. The SO_2 emission rate listed in the RBLC is 6.7 lb/hr.

Step 1 - Identification of SO_2 Control Technology for the Combined Cycle Gas Turbines
From research, the Department identified the following technologies as available for the control of SO_2 emissions from the fuel oil-fired combined cycle gas turbines:

(a) Ultra-Low Sulfur Diesel
The theory of ULSD was discussed in detail in the SO_2 BACT for the fuel oil-fired simple cycle turbines and will not be repeated here. The Department considers ULSD a technically feasible control technology for the fuel oil-fired combined cycle gas turbines.

(b) Light Straight Run Turbine Fuel (LSR)
EU 5 typically combusts LSR when not in startup. EU 6 will also combust LSR when not in startup when installed. The sulfur content of the LSR is limited to no more than 0.05 percent by weight as required by Condition 15.1 of Operating Report AQ0110TVP03. The Department considers operating LSR a technically feasible control technology for the fuel oil-fired combined cycle gas turbines.

(c) Low Sulfur Fuel
The theory of low sulfur fuel was discussed in detail in the SO_2 BACT for the fuel oil-fired simple cycle turbines and will not be repeated here. The Department considers low sulfur fuel a technically feasible control technology for the fuel oil-fired combined cycle gas turbines.

(d) Limited Operation
The theory behind limited operation for EUs 5 and 6 was discussed in detail in the NOx BACT for the fuel oil-fired combined cycle gas turbines and will not be repeated here. Due to EUs 5 and 6 currently operating under limits, the Department considers limited operation a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(e) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired combined cycle gas turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the fuel oil-fired combined cycle gas turbines.

Step 2 - Eliminate Technically Infeasible SO_2 Technologies for the Combined Cycle Gas Turbines
All control technologies identified are technically feasible for the fuel oil-fired combined cycle gas turbines.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Combined Cycle Gas Turbines
The following control technologies have been identified and ranked by efficiency for control of SO_2 emissions from the fuel oil-fired combined cycle gas turbines:

(a)	Ultra-Low Sulfur Diesel	(50% Control)
(e)	Good Combustion Practices	(Less than 40% Control)
(b)	Light Straight Run Turbine Fuel	(0% Control)
(d)	Limited Operation	(0% Control)
(c)	Low Sulfur Fuel	(0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Low sulfur fuel is listed as 0% control as it has the same fuel sulfur content requirements as the light straight run turbine fuel that is currently combusted in the fuel oil-fired combined cycle gas turbines.

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA provided an economic analysis for switching the fuel combusted in the combined cycle gas turbines to ultra-low sulfur diesel. A summary of the analyses for EUs 5 and 6 is shown below:

Table 5-8. GVEA Economic Analysis for Technically Feasible SO_2 Control for EUs 5 and 6

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD	6.0	3.0	--	$27,846,454	$9,282,151
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

GVEA contends that the economic analysis indicates the level of SO_2 reduction does not justify the use of ULSD or low sulfur fuel based on the excessive cost per ton of SO_2 removed per year.

GVEA proposes the following as BACT for SO_2 emissions from the combined cycle gas turbines:

(a) SO_2 emissions from EUs 5 and 6 shall combust Light Straight Run Turbine Fuel (30 ppm S in fuel)

Department Evaluation of BACT for SO_2 Emissions from the Combined Cycle Gas Turbines

The Department reviewed GVEA's proposal for the fuel oil-fired combined cycle gas turbines and finds that switching from LSR to ULSD is not economically feasible. The Department does not agree that the cost effectiveness should be based upon the annual cost of USLD, but on the difference in cost between the current fuel and ULSD. However, due to the reduction in SO_2 from LSR to ULSD only being 3.0 tpy the Department did not revise the cost analysis.

Step 5 - Selection of SO_2 BACT for the Combined Cycle Gas Turbines

The Department's finding is that BACT for SO_2 emissions from the fuel oil-fired combined cycle gas turbines is as follows:

(a) Except during startup, SO_2 emissions from EUs 5 and 6 shall be controlled by limiting the fuel combusted in the turbines to light straight run turbine fuel (30 ppmw S in fuel);

(b) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation; and

(c) Compliance with the proposed fuel sulfur content limit will be demonstrated with fuel shipment receipts and/or fuel test results for sulfur content.

5.3 SO_2 BACT for the Large Diesel-Fired Engine (EU 7)

Possible SO_2 emission control technologies for large engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.100 to 17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 5-9.

Table 5-9. RBLC Summary Results for SO_2 Control for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Low Sulfur Diesel	27	0.005 – 0.02
Federal Emission Standards	6	0.001 – 0.005
Limited Operation	6	0.005 – 0.006
Good Combustion Practices	3	None Specified
No Control Specified	11	0.005 – 0.008

RBLC Review
A review of similar units in the RBLC indicates combustion of low sulfur fuel, limited operation, good combustion practices, and compliance with the federal emission standards are the principle SO_2 control technologies installed on large diesel-fired engines. The lowest SO_2 emission rate listed in the RBLC is 0.001 g/hp-hr.

Step 1 - Identification of SO_2 Control Technology for the Large Diesel-Fired Engine
From research, the Department identified the following technologies as available for control of SO_2 emissions from diesel-fired engines rated at 500 hp or greater:

(a) Ultra-Low Sulfur Diesel
The theory of ULSD was discussed in detail in the SO_2 BACT for the fuel oil-fired simple cycle gas turbines and will not be repeated here. The Department considers ULSD a technically feasible control technology for the large diesel-fired engine.

(b) Federal Emission Standards
The theory of federal emission standards was discussed in detail in the NOx BACT for the large diesel-fired engine and will not be repeated here. The Department does not consider federal emission standards a feasible control technology for the large diesel-fired engine.

(c) Limited Operation
The theory of limited operation for EU 7 was discussed in detail in the NOx BACT for the large diesel-fired engine and will not be repeated here. The Department considers limited operation as a technically feasible control technology for the large diesel-fired engine.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of NOx emissions. The Department considers GCPs a technically feasible control technology for the large diesel-fired engine.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for the Large Engine
As explained in Step 1 of Section 5.4, the Department does not consider federal emission standards a technically feasible control technology to control SO_2 emissions from the large diesel-fired engine.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Large Diesel-Fired Engine
The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from the large diesel-fired engine:

(a) Ultra-Low Sulfur Diesel (99% Control)
(d) Good Combustion Practices (Less than 40% Control)
(c) Limited Operation (0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA provided an economic analysis of the control technologies available for the large diesel-fired engine to demonstrate that the use of ULSD with limited operation is not economically feasible on these units. A summary of the analysis for EU 7 is shown below:

Table 5-9. GVEA Economic Analysis for Technically Feasible SO_2 Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD	0.01005	0.0099	--	$444	$45,072
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

GVEA contends that the economic analysis indicates the level of SO_2 reduction does not justify the use of ULSD based on the excessive cost per ton of SO_2 removed per year.

GVEA proposed the following as BACT for SO_2 emissions from the diesel-fired engine:

(a) SO_2 emissions from the large diesel-fired engine shall not exceed 0.05 weight percent sulfur; and

(b) Maintain good combustion practices.

Department Evaluation of BACT for SO_2 Emissions from the Large Diesel-Fired Engine
The Department reviewed GVEA's proposal for the large diesel-fired engine and finds that ULSD is not an economically feasible control technology. The Department does not agree that the cost effectiveness be based upon the annual cost of USLD, but on the difference in cost between the current fuel and ULSD. However, due to the annual operational limit on EU 7, and the reduction in SO_2 emissions by using ULSD only being 0.0099 tpy the Department did not revise the cost analysis.

Step 5 - Selection of SO_2 BACT for the Large Diesel-Fired Engine
The Department's finding is that the BACT for SO_2 emissions from the diesel-fired engine is as follows:

(a) SO_2 emissions from EU 7 shall be controlled by combusting fuel that does not exceed 0.05 weight percent sulfur at all time the unit is in operation;

(b) SO_2 emissions from EU 7 shall be controlled by limiting operation to no more than 52 hours per 12 month rolling period;

(c) Compliance with the SO_2 emission limit while firing diesel fuel will be demonstrated by fuel shipment receipts and/or fuel test results for sulfur content; and

(d) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of operation.

The following table lists the proposed BACT determination for this facility along with those for other diesel-fired engines rated at more than 500 hp in the Serious PM-2.5 nonattainment area.

Table 5-10. Comparison of SO_2 BACT for Large Diesel-Fired Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	8 Large Diesel-Fired Engines	> 500 hp	15 ppmw S in fuel	Limited Operation Good Combustion Practices Ultra-Low Sulfur Diesel
UAF	Large Diesel-Fired Engine	13,266 hp	15 ppmw S in fuel	Limited Operation Good Combustion Practices Ultra-Low Sulfur Diesel
GVEA North Pole	Large Diesel-Fired Engine	600 hp	500 ppmw S in fuel	Limited Operation Good Combustion Practices
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel

5.4 SO_2 BACT for the Propane-Fired Boilers (EUs 11 and 12)

Possible SO_2 emission control technologies for the propane-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.310, Gas-Fired Boilers (<100 MMBtu/hr). The search results for gas-fired boilers are summarized in Table 5-11.

Table 5-11. SO_2 Control for Gas-Fired Boilers with a Rating < 100 MMBtu/hr

Control Technology	Number of Determinations	Emission Limits
Low Sulfur Fuel	6	0.03 – 0.12 lb/hr
Good Combustion Practices	4	0.0048 – 0.6 lb/MMBtu
Pipeline Quality Natural Gas	28	0.0006 – 0.0048 lb/MMBtu
No Control Specified	4	0.0021 lb/MMBtu

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and combustion of low sulfur fuel are the principle SO_2 control technologies installed on propane-fired boilers. The lowest SO_2 emission rate listed in the RBLC is 0.0006 lb/MMBtu.

Step 1 - Identification of SO_2 Control Technology for the Propane-Fired Boilers
From research, the Department identified the following technologies as available for SO_2 control for the propane-fired boilers:

(a) Low Sulfur Fuel
The theory of low sulfur fuel was discussed in detail in the PM-2.5 BACT for the propane-fired boilers and will not be repeated here. The Department considers low sulfur fuel a technically feasible control technology for the propane-fired boilers.

(b) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle gas turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2. The Department considers GCPs a technically feasible control technology for the propane-fired boilers.

Step 2 - Eliminate Technically Infeasible SO_2 Technologies for the Propane-Fired Boilers
All identified control devices are technically feasible technologies for the propane-fired boilers.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Propane-Fired Boilers
GVEA has accepted the only technically feasible control technology for the propane-fired boilers. Therefore, ranking is not required.

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA proposed the following as BACT for SO_2 emissions from the propane-fired boilers:

(a) SO_2 emissions from the operation of the propane-fired boilers shall be controlled by using low sulfur fuel at all times of operation.

(b) SO_2 emissions from the propane-fired boilers shall not exceed 0.0012 lb/kgal over a 4-hour averaging period.

Department Evaluation of BACT for SO_2 Emissions from the Propane-Fired Boilers
The Department reviewed GVEA's proposal for the propane-fired boilers and finds that the SO_2 emission rate provided by GVEA was erroneously calculated. The Department used AP-42 Table 1.5-1 emission factor for propane combustion (0.10S lb/1,000 gal, where S = gr/100 scf) and using the existing sulfur limit in Condition 11 of the stationary source's Operating Permit AQ0110TVP03 (120 ppmv) The Department corrected this emission factor to 0.75 lb/1,000 gal, assuming 16 ppmv sulfur = 1 gr/100 scf.

Step 5 - Selection of SO_2 BACT for the Propane-Fired Boilers
The Department's finding is that BACT for SO_2 emissions from the propane-fired boilers is as follows:

(a) SO_2 emissions from EUs 11 and 12 shall be controlled by only combusting gas fuel (propane) with a total sulfur content of no more than 120 ppmv, or direct emissions of 0.75 lb/1,000 gal;

(b) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation; and

(c) Compliance with the emission rate limit will be demonstrated with fuel shipment receipts and/or fuel tests for sulfur content.

6. BACT DETERMINATION SUMMARY

Table 6-1. NOx BACT Limits

EU ID	Description	Capacity	BACT Limit	BACT Control
1	Fuel Oil-Fired Simple Cycle Gas Turbine	672 MMBtu/hr	0.044 lb/MMBtu	Limited Operation Selective Catalytic Reduction Water Injection Good Combustion Practices
2	Fuel Oil-Fired Simple Cycle Gas Turbine	672 MMBtu/hr	0.070 lb/MMBtu	
5	Fuel Oil-Fired Combined Cycle Gas Turbine	455 MMBtu/hr	0.024 lb/MMBtu	Limited Operation Selective Catalytic Reduction Water Injection Good Combustion Practices
6	Fuel Oil-Fired Combined Cycle Gas Turbine	455 MMBtu/hr	0.024 lb/MMBtu	
7	Large Diesel-Fired Engine	619 hp	10.9 g/hp-hr	Turbocharger and Aftercooler Limited Operation Good Combustion Practices
11	Propane-Fired Boiler	5.0 MMBtu/hr	0.030 lb/MMBtu	Propane as Fuel Low NOx Burners Good Combustion Practices
12	Propane-Fired Boiler	5.0 MMBtu/hr	0.030 lb/MMBtu	

Table 6-2. PM-2.5 BACT Limits

EU ID	Description	Capacity	BACT Limit	BACT Control
1	Fuel Oil-Fired Simple Cycle Gas Turbine	672 MMBtu/hr	0.012 lb/MMBtu	Low Ash Fuel Limited Operation Good Combustion Practices
2	Fuel Oil-Fired Simple Cycle Gas Turbine	672 MMBtu/hr	0.012 lb/MMBtu	
5	Fuel Oil-Fired Combined Cycle Gas Turbine	455 MMBtu/hr	0.012 lb/MMBtu	Limited Operation Good Combustion Practices
6	Fuel Oil-Fired Combined Cycle Gas Turbine	455 MMBtu/hr	0.012 lb/MMBtu	
7	Large Diesel-Fired Engine	619 hp	0.32 g/hp-hr	Limited Operation Good Combustion Practices
11	Propane-Fired Boiler	5.0 MMBtu/hr	0.008 lb/MMBtu	Propane as Fuel Good Combustion Practices
12	Propane-Fired Boiler	5.0 MMBtu/hr	0.008 lb/MMBtu	

Table 6-3. SO_2 BACT Limits

EU ID	Description	Capacity	BACT Limit	BACT Control
1	Fuel Oil-Fired Simple Cycle Gas Turbine	672 MMBtu/hr	15 ppmw S in fuel	Limited Operation Ultra-Low Sulfur Diesel Good Combustion Practices
2	Fuel Oil-Fired Simple Cycle Gas Turbine	672 MMBtu/hr	15 ppmw S in fuel	
5	Fuel Oil-Fired Combined Cycle Gas Turbine	455 MMBtu/hr	30 ppmw S in fuel	Limited Operation Light Straight Run Turbine Fuel Good Combustion Practices
6	Fuel Oil-Fired Combined Cycle Gas Turbine	455 MMBtu/hr	30 ppmw S in fuel	
7	Large Diesel-Fired Engine	619 hp	500 ppmw S in fuel	Limited Operation Good Combustion Practices
11	Propane-Fired Boiler	5.0 MMBtu/hr	120 ppmv S in fuel	Propane as Fuel Good Combustion Practices
12	Propane-Fired Boiler	5.0 MMBtu/hr	120 ppmv S in fuel	

Table 6-2. PM-2.5 BACT Limits

EU ID	Description	Capacity	BACT Limit	BACT Control
1	Fuel Oil-Fired Simple Cycle Gas Turbine	672 MMBtu/hr	0.012 lb/MMBtu	Low Ash Fuel Limited Operation Good Combustion Practices
2	Fuel Oil-Fired Simple Cycle Gas Turbine	672 MMBtu/hr	0.012 lb/MMBtu	
5	Fuel Oil-Fired Combined Cycle Gas Turbine	455 MMBtu/hr	0.012 lb/MMBtu	Limited Operation Good Combustion Practices
6	Fuel Oil-Fired Combined Cycle Gas Turbine	455 MMBtu/hr	0.012 lb/MMBtu	
7	Large Diesel-Fired Engine	619 hp	0.32 g/hp-hr	Limited Operation Good Combustion Practices
11	Propane-Fired Boiler	5.0 MMBtu/hr	0.008 lb/MMBtu	Propane as Fuel Good Combustion Practices
12	Propane-Fired Boiler	5.0 MMBtu/hr	0.008 lb/MMBtu	

Table 6-3. SO_2 BACT Limits

EU ID	Description	Capacity	BACT Limit	BACT Control
1	Fuel Oil-Fired Simple Cycle Gas Turbine	672 MMBtu/hr	15 ppmw S in fuel	Limited Operation Ultra-Low Sulfur Diesel Good Combustion Practices
2	Fuel Oil-Fired Simple Cycle Gas Turbine	672 MMBtu/hr	15 ppmw S in fuel	
5	Fuel Oil-Fired Combined Cycle Gas Turbine	455 MMBtu/hr	30 ppmw S in fuel	Limited Operation Light Straight Run Turbine Fuel Good Combustion Practices
6	Fuel Oil-Fired Combined Cycle Gas Turbine	455 MMBtu/hr	30 ppmw S in fuel	
7	Large Diesel-Fired Engine	619 hp	500 ppmw S in fuel	Limited Operation Good Combustion Practices
11	Propane-Fired Boiler	5.0 MMBtu/hr	120 ppmv S in fuel	Propane as Fuel Good Combustion Practices
12	Propane-Fired Boiler	5.0 MMBtu/hr	120 ppmv S in fuel	

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

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November 16, 2017

Naomi Knight, Environmental Officer
Golden Valley Electric Association
PO Box 71249
Fairbanks, AK 99707-1249

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum from Golden Valley Electric Association (GVEA) for the North Pole Power Plant and Zehnder Facility by December 22, 2017

Dear Ms. Knight:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that GVEA North Pole and Zehnder and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to a Serious Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measure (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as GVEA North Pole and Zehnder. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analyses are a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an email to Ms. Naomi Knight at GVEA on May 11, 2017 notifying her of the reclassification

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)
[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(4)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.
[3] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

to Serious and included a request for the BACT analysis to be completed by August 8, 2017. The BACT analyses from GVEA North Pole and Zehnder, which included emission units found in Operating Permits AQ0110TVP03 and AQ0109TVP03, were submitted by email to the Department on August 30, 2017.

ADEC and EPA reviewed the BACT analyses provided for GVEA North Pole and Zehnder Facilities and ADEC is requesting additional information to assist it in making a legally and practicably enforceable BACT determinations for the sources. Both the ADEC and EPA comments are enclosed in this letter. ADEC requests a response by December 22, 2017. If ADEC does not receive a response to this information request by this date, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facilities' infrastructure and without additional information may select a more stringent BACT for your facilities in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public review along with any precursor demonstrations and BACM analysis before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes final BACT determinations for GVEA North Pole and Zehnder, it must include the determinations in Alaska's Serious SIP that then ultimately requires approval by EPA.[3] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented prior to June 9, 2021 – 4 years after reclassification.[4]

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM) consideration. MSMs will be a required element of the state implementation plan if the State applies for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

ADEC appreciates the cooperation that we've received from GVEA. ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Denise Koch, Director
Division of Air Quality

[3] https://www.gpo.gov/fdsys/pkg/USCODE-2011-title42/html/USCODE-2011-title42-chap85-subchapI-partD-subpart4-sec7513a
[4] 40 CFR 51.1010(4)

Enclosures:

November 16, 2017	ADEC Request for Additional Information for GVEA North Pole and Zehnder BACT Analyses;
November 15, 2017	EPA GVEA BACT Analysis Review Comments
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for GVEA North Pole and Zehnder

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality
Jim Plosay, ADEC/ Air Quality
Aaron Simpson, ADEC/Air Quality
Naomi Knight/GVEA
Tim Hamlin, EPA Region 10
Dan Brown, EPA Region 10
Zach Hedgpeth, EPA Region 10

ADEC Request for Additional Information
Golden Valley Electric Association – North Pole and Zehnder Facilities
BACT Analysis Review
August 2017

November 16, 2017

Please address the following comments by providing the additional information identified by December 22, 2017. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public review. In order to provide this additional review opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public review period or based upon the new information provided in response to this information request.

This document does not represent a final BACT determination by ADEC. Please contact Aaron Simpson at aaron.simpson@alaska.gov with any questions regarding ADEC's comments.

1. Equipment Life – Page 31 of the North Pole analysis and Page 27 of the Zehnder analysis state "Because of the harsh climate, equipment in this far north location experiences more wear and tear than equipment in moderate climates. On this basis, a ten year return on the [water injection and] SCR system is assumed to be reasonable." This same assumption is made for the other control devices. ADEC identified that the EPA Air Pollution Control Cost Manual[1] uses a hypothetical example that assumes the control equipment has a useful life of ten years. However the cost analyses must use a reasonable estimate of the actual life of the control equipment for each control technology. In order to use an equipment life that is shorter than 30 years, evidence must be provided to support the claim that 10 years is a reasonable timeframe for equipment life. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as turbines.

2. BACT limits – BACT limits by definition, are numerical emission limits. However regulation allows a design, equipment, or work/operational practices if technological or economic limitations make a measurement methodology infeasible. Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for pollutant for each emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. Measures to minimize the occurrence of these periods, or to minimize emissions during these periods are control options. Combinations of steady-state control options and SSM control options can be combined to create distinct control strategies. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

[1] U.S. EPA OAQPS Air Pollution Control Cost Manual, 6th Edition [EPA/452/B-02-001]

3. Cost Analyses – Page 44 of the North Pole analysis indicates that EUs 1 and 2 have historically low run hours. Page 34 of the Zehnder analysis state that "GVEA believes that an economic analysis based on the actual emissions and operations of these turbines is more relevant for purposes of determining viable ways to reduce PM2.5 ambient concentrations in the Fairbanks area." However, all BACT cost effectiveness calculations must be based upon the potential to emit, and not on historic operation. Please update the cost analyses using the unrestricted potential to emit for each of the emissions units or propose operational limits (including control efficiencies associated with limited operation). Additionally, see Comments 4, 5, and 6 for additional information related to retrofit costs, baseline emissions, and factor of safety.
4. Retrofit Costs – EPA's Control Cost Manual indicates that study-level cost estimates (± 30 percent) should not include a retrofit factor greater than 30 percent, so detailed cost estimates (± 5 percent) is required for higher factors. High retrofit cost factors (50 percent or more) may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement). Provide detailed cost analyses and justification for any difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analyses.
5. Baseline Emissions – Include the baseline emissions for all emission units included in the analyses. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). NSPS and NESHAP requirements are not considered in calculating the baseline emissions. The baseline is usually the legal limit that would exist, but for the BACT determination. Baseline takes into account the effect of equipment that is part of the design of the unit (e.g., water injection and low NOx burners) because they are considered integral components to the unit's design. If the uncontrolled emission rate is 'soft,' run the cost effectiveness calculations using two or three different baselines.
6. Factor of Safety – If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.
7. Good Combustion Practices –For each emission unit type (oil fuel-fired turbines, combined cycle turbines, emergency generator engines, and boilers) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices. Include any work or operational practices that will be implemented and describe how continuous compliance with good combustion practices will be achieved.
8. Alternate Fuel – Page 96 of the North Pole analysis indicates that "the capital costs incurred to switch fuels [to ULSD] would include an estimated capital cost of $30,425,000 to install bulk fuel storage." Please provide a full evaluation of the fuel change impacts, fuel pricing, and bulk storage facility pricing. Based on the fuel supply information gathered for the BACM analysis for the Fairbanks Serious SIP, the Department is aware of more than one supplier of alternate fuels. Please make sure all supplier cost information is addressed for all emission units that are evaluating a fuel switch.
9. Cost Analysis Spreadsheets – The BACT analyses for North Pole and Zehnder Facilities include emissions, cost effectiveness, and incremental cost effectiveness calculations, but none of these calculations have been submitted in a spreadsheet format. Please submit the electronic versions of the spreadsheets used in determining the cost effectiveness for any control technology not selected as the highest level of control.

10. Confidential Documentation – The BACT analyses for North Pole and Zehnder Facilities have indicated that details related to costs were included in a separately submitted package under application for confidentiality of records. Please submit the supporting documentation so the Department can conduct a more detailed review of the analyses and calculations.
11. Control Technology Availability – For the North Pole Facility, include Flue Gas Recirculation in the review of NOx control technologies for diesel-fired boilers. Rank the control technologies by efficiency (specify % control). Select the best performing control technology as BACT or provide specific energy, environmental, and economic impacts and other costs justification for why each better performing control technology was not selected instead of good combustion practices. Provide a numerical NOx emission limit for the diesel-fired boilers or identify the work or operational practices that will be utilized to ensure compliance with proposed limits.

GVEA – North Pole and Zehnder Power Plants
BACT Analysis Review Comments
Reports dated August 2017 – GVEA

Zach Hedgpeth, PE
EPA Region 10 – Seattle
November 15, 2017

Note: These comments represent a partial review of the BACT analyses for the GVEA North Pole and Zehnder facilities, since none of the emission calculations or cost analysis calculations have been submitted in spreadsheet format. Also, certain documents forming the basis for costs used in the analyses have not been submitted due to confidentiality concerns. EPA Region 10 will conduct a more detailed review of the analysis and calculations following submittal of this information.

1. Equipment Life – Page 31 of the North Pole analysis[1] states "a standardized ten year return on investment at seven percent interest rate is assumed". This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in this far north location experiences more wear and tear than equipment in moderate climates". The analysis includes no further information to support the assumption of a ten year equipment life, nor the underlying assertion regarding wear and tear. The analyses must use a reasonable estimate of the actual life of the control equipment for each control technology, based on the best evidence available. In order to use an equipment life that is shortened based on the harsh climate, evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as turbines.
2. Control Technology Availability – Technically feasible control technologies may only be eliminated based on lack of availability if the analysis includes documented information from multiple control equipment vendors (who provide the technology in question) which confirms the technology is not available for the emission unit in question. For example, the North Pole analysis concludes that flue gas recirculation is not technically feasible for NO_X control based on the statement that "FGR is not available with the vendor-provided Low-NO_X combustor retrofit package for these boilers." Written documentation from multiple vendors must be included to support this statement.
3. Basis for Costs and Assumptions – Documents cited in the analyses which form the basis for costs used in the analyses and assumptions made in the analyses must be provided. For example, within the analysis of SCR for the North Pole facility (see page 30), many of the costs used for SCR appear to be based either on "past project experience" or "information from other projects". Detailed information forming the basis for these cost assumptions in the analysis must be submitted as part of the BACT analysis. Certain other costs are estimated based on a 1993 EPA document referred to as the "Alternative Control Techniques Document". A copy of this document must be included as an attachment to the analysis if this document forms the basis for information used in the analysis. EPA Region 10 will conduct a more detailed review of the calculations following submittal of this and other requested information.
4. EPA Cost Spreadsheets – Note that the EPA has recently updated the cost manual chapter pertaining to SCR, and developed a cost spreadsheet to be used for evaluation of this technology

[1] Golden Valley Electric Association, Voluntary $PM_{2.5}$ Serious Nonattainment Area BACT Analysis for the North Pole Facility, August 2017

for cost effectiveness[2]. The EPA spreadsheet was developed to evaluate cost effectiveness of SCR as applied to boilers, so cannot be directly applied to turbines. However, the cost analyses for SCR developed for the GVEA emission units must be consistent with the updated cost manual chapter.

5. SCR Space Constraints – The North Pole analysis includes a number of statements regarding space constraints and other installation challenges that the analysis claims complicate or possibly preclude installation of SCR on the turbines, however detailed drawings, site plans and other information have not been submitted to substantiate these claims. One aerial photo of the facility has been included, but all areas surrounding the buildings housing the emission units are marked as unavailable due to "maintenance access areas" or "fuel delivery truck route". Establishing the entire area surrounding the buildings as unavailable for control equipment based on these purposes would require substantially more detailed justification than has been provided. Additionally, in order to establish SCR as not technically feasible due to space constraints or other retrofit factors, detailed site specific information must be submitted in order to establish the basis for such a determination. Installation factors which would complicate the retrofit installation of the control technology should be evaluated by a qualified control equipment vendor and be reflected in a site-specific capital equipment purchase cost and site specific installation cost estimate or quote. Lacking site-specific cost information, all factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor.

6. Costs Not Included – In several locations (i.e., p. 40 of the North Pole analysis), the analyses include the statement that cost estimates are "conservatively low" because they do not include the cost of support systems needed to operate the control equipment. EPA Region 10 believes these costs should be included in the analyses, based on site-specific capital and installation estimates or quotes provided by qualified control equipment vendors. Justification for inclusion of each retrofit-related cost must be included in the analyses. Development of reasonably accurate cost estimates for these retrofit projects is necessary in order to inform the BACT determination for each emission unit and pollutant.

7. Potential vs. Actual Emissions – In some places, the analyses propose BACT determinations based on use of actual emissions. All BACT cost effectiveness calculations must use potential-to-emit (PTE), regardless of the emission unit usage history or actual historical emission rates. The facility should consider operating limits in cases where certain emission units do not need to retain relatively high PTE for facility operational purposes.

[2] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

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April 24, 2015

Naomi Knight, Environmental Officer
Golden Valley Electric Association
PO Box 71249
Fairbanks, AK 99707-1249

Subject: Voluntary BACT Analysis for Zehnder Facility and North Pole Power Plant

Dear Ms. Knight:

Portions of the Fairbanks North Star Borough are in nonattainment with the 24-hour National Ambient Air Quality Standard for Fine Particulate Matter (PM 2.5). The Alaska Department of Environmental Conservation (ADEC) expects that the Environmental Protection Agency (EPA) will change the nonattainment designation from a Moderate Area to a Serious Area in June 2016. Once EPA designates the area as Serious, an 18-month clock begins for submittal of an implementation plan that includes best available control technologies (BACT) analysis and determination for stationary sources with over 70 tons per year (TPY) potential to emit (PTE) for PM2.5 or its precursors.

ADEC has neither the funding nor the in depth knowledge of your facility's infrastructure to determine the most appropriate BACT for your facility. Without the information or resources necessary to conduct detailed cost analysis and produce supporting documentation, ADEC may select a more stringent BACT for your facility in order to be approvable by EPA. In addition, 18 months is likely not adequate to complete a thorough BACT analysis.

Therefore, ADEC requests that your facility voluntarily begin the BACT analysis. We request that you submit an initial BACT analysis to ADEC by December 2015 and the final BACT analysis by March 2016 to ADEC. ADEC is required to make a BACT determination for every eligible facility within the designated PM2.5 nonattainment area and final BACT determinations are ultimately reviewed by EPA and subject to federal approval as part of the federally required PM2.5 implementation plan.

Background

EPA required that ADEC submit a State Implementation Plan (SIP) because portions of the Fairbanks North Star Borough (FSNB) are in nonattainment with the health based 24-hour National

Ambient Air Quality Standard for PM2.5. ADEC submitted an initial, Moderate Area PM2.5 SIP for FNSB to EPA on December 31, 2014.

Unfortunately, this Moderate Area SIP was developed as an impracticable SIP because modeling was unable to demonstrate that attainment with the health standard was possible by December 30, 2015. Preliminary air monitoring results also indicate that FNSB will not demonstrate attainment in 2015. Attainment is calculated on a rolling three year average of the highest 98th percentile concentration at each monitor. When those monitoring results become final in May 2016 and an official three year design value is calculated, the FNSB non-attainment area will remain over the 24-hr PM 2.5 standard of 35 $\mu g/m^3$. The final determination of this design value will result in the FNSB non-attainment area being reclassified from a Moderate Area to a Serious Area[1] (40 CRF Parts 50, 51 and 93). This reclassification will happen by operation of law as outlined in Clean Air Act Sections 188 and 189. It is anticipated that the formal designation to Serious Area will occur in June 2016.

A Serious Area designation will result in several new, more stringent requirements, one of which is that all source categories in the nonattainment area that meet the BACT threshold of 70 TPY PTE for $PM_{2.5}$ and its precursor pollutants (NOx, SO2, VOC, NH3) must be analyzed for Best Available Control Measures (BACM). As part of BACM, a Best Available Control Technologies (BACT) analysis will be required. The Serious Area BACT trigger requires the same approach as a PSD/NSR BACT project. A Serious non-attainment area BACT limit is set using a top-down analysis on a case-by-case basis taking into account energy, environmental and economic impacts, and costs. The analysis must include all emission units at the source.

The timelines for completion of the BACT analysis, subsequent BACT determination, and the submittal of the Serious Area SIP are outlined in the preamble of the Particulate Matter 10 (PM10) rule and reconfirmed in the newly proposed $PM_{2.5}$ Implementation Rule[2]. Both rules require a completed SIP 18 months after designation to Serious. This 18 month time period does not allow enough time to thoroughly evaluate BACT, update the emission inventory, complete the modeling and allow for development and processing for a Serious Area SIP.

ADEC believes that it is best for facilities to complete the BACT analysis for their own facilities. ADEC does not have the funding to develop the analysis nor the in depth knowledge of each sources' infrastructure. ADEC would therefore base the cost analysis on the installation of control equipment without being able to factor in all the costs associated with retrofitting existing equipment. Without the detailed cost analysis and supporting documentation to support less stringent BACT options, it is doubtful that the BACT portions of the Serious SIP will be approvable without using the most stringent measures.

By requesting an early BACT analysis for facilities before the official Serious Area designation, it will help ADEC meet the following timelines and ultimately submit a Serious Area SIP to EPA by the required due date. Early analysis also has the potential to increase flexibility for each Stationary Source under the rules.

[1] 40 CFR Parts 50,51 and 93 http://www.epa.gov/airquality/particlepollution/actions.html

[2] http://www.epa.gov/airquality/particlepollution/actions.html

- Serious Area SIP inventory development starts: January, 2015
- BACT kick off meeting: March 5, 2015
- Submit initial BACT results to ADEC: December, 2015
- Submit complete/final BACT analysis to ADEC: March, 2016
- Serious Area SIP modeling by ADEC starts: March, 2016
- Serious Area designation by EPA (Expected): June, 2016
- Serious Area SIP draft: December, 2016
- Serious Area SIP public notice period: February, 2017
- Serious Area SIP submitted by ADEC to EPA: December, 2017

Meeting the BACT analysis requirements is a major component of a Serious SIP. This is a challenging issue. It is important that ADEC accurately reflect the contributions of industrial sources to the air pollution problem and the potential improvements available within this emission sector along with the other emission sources in the community.

ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Denise Koch, Director
Division of Air Quality

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
John Kuterbach, ADEC/ Air Quality
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality

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Denise Koch, Director
Division of Air Quality
Department of Environmental Conservation
410 Willoughby Avenue, Suite 303
PO Box 111800
Juneau, AK 99811-1800

RE: Response to request for additional information for the Best Available Control Technology Technical Memorandum from Golden Valley Electric Association (GVEA) for the North Pole Power Plant and Zehnder Facility.

Dear Ms. Koch,

Golden Valley Electric Association (GVEA) received a request for additional information from the Alaska Department of Environmental Conservation (ADEC) on November 16, 2017 regarding the Best Available Control Technology (BACT) analyses previously submitted for the North Pole Power Plant and Zehnder Facility. The request for additional information included a set of 11 comments from ADEC and 7 comments from EPA region 10. Listed below is each comment followed by GVEA's response.

Overall, GVEA understands from a regulatory perspective that ADEC and EPA wish to have as much information as possible available to substantiate BACT determinations, and that the highest level of engineering detail would require hundreds of thousands of dollars in engineering studies; the real studies that would identify true retrofit feasibility and true costs. In preparing the BACT analyses GVEA worked to provide a level of detail that is commonly commensurate with BACT analyses and practical to obtain. With respect to the evaluation of NOx BACT in particular, GVEA finds itself in a dilemma while waiting for the outcome of ADEC's NOx precursor demonstration, hesitant to over invest in costly engineering studies that many not be necessary.

ADEC Comments

1. Equipment Life – Page 31 of the North Pole analysis and Page 27 of the Zehnder analysis state "Because of the harsh climate, equipment in this far north location experiences more wear and tear than equipment in moderate climates. On this basis, a ten year return on the [water injection and] SCR system is assumed to be reasonable." This same assumption is made for the other control devices. ADEC identified that the EPA Air Pollution Control Cost Manual uses a hypothetical example that assumes the control equipment has a useful life of ten years. However the cost analyses must use a reasonable estimate of the actual life of the control equipment for each control technology. In order to use an equipment life that is shorter than 30 years, evidence must be provided to support the claim that 10 years is a reasonable timeframe for equipment life. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as turbines.

   GVEA response:

   The 10-year equipment life as used in the calculations for capital recover in the Zehnder Plant and North Pole Plant BACT analyses is consistent with established ADEC practice and previously approved PSD permitting BACT analyses evaluated by ADEC over the past 20 years. GVEA believes this 10-year equipment life timeframe is appropriate for equipment operated in the harsh Alaska climate and falls within the equipment lifetimes used in the EPA Air Pollution Control Cost Manual (sixth edition, EPA/452/B-02-001, Control Cost Manual) which uses equipment lifetimes between 5 and 30 years. Ten, 15, and 20-year lifespans are frequently used in the manual.

   As examples, two recent Alaskan permits with BACT analyses based on a 10-year equipment life include

   - *The BACT analysis for the Doyon Utilities JBER Electric, Gas & Sanitary Services Permit AQ0237CPT04 dated May 8, 2013. See the footnote to Table B-4 of the TAR to that permit.*
   - *The BACT analysis for the Agrium U.S. Inc. Kenai Nitrogen Operations Permit AQ0083CPT06 dated January 6, 2015. See the table on page 24 (of 171) in the TAR to that permit.*

2. BACT limits – BACT limits by definition, are numerical emission limits. However regulation allows a design, equipment, or work/operational practices if technological or economic limitations make a measurement methodology infeasible. Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for pollutant for each emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. Measures to minimize the occurrence of these periods, or to minimize emissions during these periods are control options. Combinations of steady-state control options and SSM control options can be combined to create distinct control strategies. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

GVEA response:

BACT Limits for Normal Operation

The numerical emissions limits that were proposed as BACT selections and that were provided in the Zehnder Power Plant and North Pole Power Plant BACT analyses are summarized in attached Tables 2-1 and 2-2, respectively. Averaging periods, which were inadvertently omitted from the BACT analysis reports, are also included in Tables 2-1 and 2-2.

The averaging periods provided in Tables 2-1 and 2-2 are not an indication of compliance demonstration methodology. Source testing is not an appropriate compliance demonstration methodology for the Zehnder plant and North Pole plant boilers because the units are very small, diesel-fired, and not operated continuously. Startups and shutdowns are typically unscheduled events, but source test planning and mobilization can required up to several months in Alaska because source testing teams and equipment frequently must be brought to Alaska from the Lower 48. The requirement to provide a 30 to 60 -day source test notification to ADEC and/or EPA and to prepare and obtain agency approval of a source test plan also reduces scheduling flexibility. The agency-mandated source testing protocol typically requires that three 1-hour test runs be completed for a test to be valid, while typical startups and shutdowns have a much shorter duration. As a result, retaining records demonstrating proper operation and maintenance is the appropriate compliance demonstration method. Based on the same rationale, the compliance demonstration methodology for the Zehnder plant and North Pole plant emergency diesel-fired reciprocating engines should be retaining records demonstrating proper operation and maintenance.

GVEA wishes to note that while preparing this response, one emission factor error was found in each of the Zehnder plant and North Pole plant BACT analysis reports, but in neither case is the BACT analyses affected.[1]

BACT Limits for Startup, Shutdown, and Malfunction (SSM)

The BACT affected emission units at the Zehnder and North Pole plants have short startup durations, normally ranging from 15 to 30 minutes. The shutdown durations are similarly short, typically less than 15 minutes for all of the BACT affected emission units. For startup, shutdown BACT available options are numerical emission limits, or duration

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[1] *Table 3-15 of the Zehnder report incorrectly lists the nitrogen oxides (NO_x) emission rate for EUs 3 and 4 as 0.0022 pounds per horsepower-hour (lb/hp-hr). The correct BACT emission rate for NO_x emissions from EUs 3 and 4 is 0.024 lb/hp-hr. The NO_x BACT analysis in Section 3 of the Zehnder plant report is based on the correct emission factor. Table 3-23 of the North Pole report incorrectly lists the NO_x emission rate for EU 7 as 0.0022 lb/hp-hr. The correct BACT emission rate for NO_x emissions from EU 7 is 0.031 lb/hp-hr. The NO_x BACT analysis in Section 3 of the North Pole plant report is based on the correct emission factor.*

limits. For malfunction BACT available options are numerical emission limits, or the expeditious return to normal operation or shut down for repairs.

For startup and shutdown, numerical emission limits are not a practical BACT selection for these emission units because demonstrating compliance with such a limit is not technically feasible as a practical matter. Specifically, the startup and shutdown periods are too short to enable performance testing using the methods provided in Appendix A to 40 Code of Federal Regulations (CFR) 60.

As an allowed alternative, the BACT limit available for all emission units and for all air pollutants is the specification of duration limits for startup and shutdown. This proposed work and operational practice is consistent with the BACT guidance and enables a practical methodology for demonstrating compliance during startup and shutdown period. Table 2-3 shows the proposed BACT startup and shutdown durations for emission units at the Zehnder Facility while Table 2-4 shows the proposed BACT startup and shutdown durations for emission units at the North Pole Plant.

For malfunctions, numerical emission limits are not a practical BACT selection for the Zehnder and North Pole emission units during a malfunction because demonstrating compliance with such a limit is not technically feasible as a practical matter. Specifically, predicting when or for how long a malfunction might occur is not possible because of the nature of malfunction events. As a result, demonstrating compliance with numerical emission limits during a malfunction is not practical using the performance testing methods provided in Appendix A to 40 CFR 60.

As an allowed alternative, the BACT limit for all air pollutants and emission units is to restore the malfunctioning emission unit to normal operation as soon as is practical or proceed with shutting down the emission unit until repairs can be made. This proposed work and operational practice is consistent with the BACT guidance and enables a practical methodology for demonstrating compliance during malfunction. Table 2-2 also shows the proposed malfunction BACT for the emission units at the Zehnder Facility and Table 2-4 shows the proposed BACT for the emission units at the North Pole Plant.

3. Cost Analyses – Page 44 of the North Pole analysis indicates that EUs 1 and 2 have historically low run hours. Page 34 of the Zehnder analysis state that "GVEA believes that an economic analysis based on the actual emissions and operations of these turbines is more relevant for purposes of determining viable ways to reduce PM2.5 ambient concentrations in the Fairbanks area." However, all BACT cost effectiveness calculations must be based upon the potential to emit, and not on historic operation. Please update the cost analyses using the unrestricted potential to emit for each of the emissions units or propose operational limits (including control efficiencies associated with limited operation). Additionally, see Comments 4, 5, and 6 for additional information related to retrofit costs, baseline emissions, and factor of safety.

GVEA response:

The North Pole Plant and Zehnder Plant BACT analyses reports submitted in August 2017 do provide the cost effectiveness based on potential to emit (PTE). The cost effectiveness tables and associated page numbers for each pollutant and each control evaluated are provided below in Table 3-1.

Table 3-1. Location of BACT Cost Effectiveness Based on PTE

North Pole Plant				
EU ID	**Pollutant**	**Control Cost Effectiveness Evaluated**	**Table**	**Page**
EU ID 1	NO_x	SCR with Water Injection	Table 3-5	51
EU ID 2	NO_x	SCR with Water Injection	Table 3-7	53
EU ID 1	NO_x	SCR	Table 3-9	55
EU ID 2	NO_x	SCR	Table 3-11	57
EU ID 1	NO_x	Water Injection	Table 3-13	59
EU ID 2	NO_x	Water Injection	Table 3-15	61
EU ID 1	SO_2	ULSD	Table 5-4	103
EU ID 2	SO_2	ULSD	Table 5-5	104
Zehnder Plant				
EU ID	**Pollutant**	**Control Cost Effectiveness Evaluated**	**Table**	**Page**
EU IDs 1 and 2	NO_x	SCR with Water Injection	Table 3-5	42
	NO_x	SCR	Table 3-7	44
	NO_x	Water Injection	Table 3-9	46
	SO_2	ULSD	Table 5-4	81

GVEA understands that a traditional BACT process typically evaluates control cost effectiveness based on PTE and did present those costs. GVEA also understands that BACT decisions are made on a case-by-case basis so that criteria specific to each BACT situation can be properly considered. In this case, GVEA believes that the historically low actual operating hours and associated emissions from the North Pole Plant EUs 1 and 2, and the Zehnder Plant EUs 1 and 2 are representative of the actual contribution emissions from these plants have made to the measured ambient $PM_{2.5}$ concentrations. Because the GVEA cooperative members would bear the economic burden of paying for emission controls that would in practical reality do very little to reduce regional ambient $PM_{2.5}$ concentrations, GVEA proposes that basing the BACT cost effectiveness on the historical actual operating hours is appropriate.

GVEA believes it is premature to commit to any operating limitations. Though these emission units have historically operated only a few hours on an annual basis, all of the emission units are critical to providing reliable power to our cooperative members in the event GVEA loses other generating units or is unable to receive purchased power from Southcentral Alaska. Having available generation is especially important during the coldest winter months when reliable power is critical to maintain the health and safety of

our members. Before knowing the outcome of the ADEC NO_x precursor demonstration, GVEA is uncomfortable committing to restrictions on available operating hours that may be unnecessary if the NOx precursor demonstration is successful.

4. Retrofit Costs – EPA's Control Cost Manual indicates that study-level cost estimates (± 30 percent) should not include a retrofit factor greater than 30 percent, so detailed cost estimates (± 5 percent) is required for higher factors. High retrofit cost factors (50 percent or more) may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement). Provide detailed cost analyses and justification for any difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analyses.

   GVEA response:
   GVEA did not use stand-alone retrofit factors in the BACT cost analyses presented in the August 2017 reports, rather vendor supplied cost information took into account the retrofit installation along with potential complications and cost increases associated with the Alaskan location.

5. Baseline Emissions – Include the baseline emissions for all emission units included in the analyses. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). NSPS and NESHAP requirements are not considered in calculating the baseline emissions. The baseline is usually the legal limit that would exist, but for the BACT determination. Baseline takes into account the effect of equipment that is part of the design of the unit (e.g., water injection and low NOx burners) because they are considered integral components to the unit's design. If the uncontrolled emission rate is "soft," run the cost effectiveness calculations using two or three different baselines.

   GVEA response:
   For both the Zehnder plant and North Pole plant analyses submitted in August 2017, baseline emissions were provided in Section 1, in Tables 1-2 through 1-5. The baseline emission rates incorporate existing emission control devices and enforceable emission and operating limits.

6. Factor of Safety – If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.

   GVEA response:
   GVEA did not feel safety factors were warranted and they were not included in the BACT emission limits proposed in the BACT analysis reports submitted in August 2017.

7. Good Combustion Practices –For each emission unit type (oil fuel-fired turbines, combined cycle turbines, emergency generator engines, and boilers) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices. Include any work or operational practices that will be implemented and describe how continuous compliance with good combustion practices will be achieved.

   GVEA response:
   GVEA's current practice and proposed practice to achieve good combustion practices is the adherence to the original equipment manufacturer (OEM) recommendations for operation and maintenance of all emission units. Good combustion practices are integral to these OEM recommendations, so following the recommendations intrinsically assures compliance with good combustion practices. Set points for efficient combustion are also set into the control systems and those parameters are kept constant. For building heaters the OEM guidelines are followed for tuning and operation and O_2 balance is periodically measured.

8. Alternate Fuel – Page 98 of the North Pole analysis indicates that "the capital costs incurred to switch fuels [to ULSD] would include an estimated capital cost of $30,425,000 to install bulk fuel storage." Please provide a full evaluation of the fuel change impacts, fuel pricing, and bulk storage facility pricing. Based on the fuel supply information gathered for the BACM analysis for the Fairbanks Serious SIP, the Department is aware of more than one supplier of alternate fuels. Please make sure all supplier cost information is addressed for all emission units that are evaluating a fuel switch.

   GVEA response:
   Ensuring the resilient and economical supply of fuel for both normal and emergency operations is extremely important to GVEA and as such the evaluation of fuel vendors within Alaska and the Pacific Northwest is a normal part of strategic planning. The capital costs used in the BACT were developed with the assistance of a technical memo provided by PDC Engineers, and a summary analysis provided by an Energy Analyst with Leidos Engineering. The supporting documentation is provided in the separately submitted package under request for confidentiality.

9. Cost Analysis Spreadsheets – The BACT analyses for North Pole and Zehndar Facilities include emissions, cost effectiveness, and incremental cost effectiveness calculations, but none of these calculations have been submitted in a spreadsheet format. Please submit the electronic versions of the spreadsheets used in determining the cost effectiveness for any control technology not selected as the highest level of control.

   GVEA response:
   The enclosed disk contains the electronic versions of the spreadsheets used in determining the cost effectiveness for all control technologies evaluated.

10. Confidential Documentation – The BACT analyses for North Pole and Zehnder Facilities have indicated that details related to costs were included in a separately submitted package under application for confidentiality of records. Please submit the supporting documentation so the Department can conduct a more detailed review of the analyses and calculations.

    GVEA response:
    The supporting documentation has been submitted under separate cover dated December 22, 2017

11. Control Technology Availability – For the North Pole Facility, include Flue Gas Recirculation in the review of NOx control technologies for diesel-fired boilers. Rank the control technologies by efficiency (specify % control). Select the best performing control technology as BACT or provide specific energy, environmental, and economic impacts and other costs justification for why each better performing control technology was not selected instead of good combustion practices. Provide a numerical NOx emission limit for the diesel-fired boilers or identify the work or operational practices that will be utilized to ensure compliance with proposed limits.

    GVEA response:
    Aaron Simpson of ADEC and Courtney Kimball of SLR (a GVEA consultant) discussed this question during a phone call on November 30, 2017. The North Pole facility does not have any diesel-fired boilers. Mr. Simpson indicated that the comment was meant to address the diesel-fired boilers at the Zehnder facility (EUs 10 and 11). Mr. Simpson and Ms. Kimball agreed that while Flue Gas Recirculation (FGR) is an available emission control technology, vendor information indicates that boiler efficiency would decrease as a result of FGR use. This information is provided in Section 3.2.3 of the Zehnder BACT analysis report. Upon further review of this section of the report, Mr. Simpson stated that no further response to this question was necessary.

EPA Comments

1. Equipment Life – Page 31 of the North Pole analysis states "a standardized ten year return on investment at seven percent interest rate is assumed". This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in this far north location experiences more wear and tear than equipment in moderate climates". The analysis includes no further information to support the assumption of a ten year equipment life, nor the underlying assertion regarding wear and tear. The analyses must use a reasonable estimate of the actual life of the control equipment for each control technology, based on the best evidence available. In order to use an equipment life that is shortened based on the harsh climate, evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as turbines.

GVEA response:
Please see response to ADEC Comment 1 above.

2. Control Technology Availability – Technically feasible control technologies may only be eliminated based on lack of availability if the analysis includes documented information from multiple control equipment vendors (who provide the technology in question) which confirms the technology is not available for the emission unit in question. For example, the North Pole analysis concludes that flue gas recirculation is not technically feasible for NO_x control based on the statement that "FGR is not available with the vendor-provided Low-NO_x combustor retrofit package for these boilers." Written documentation from multiple vendors must be included to support this statement.

   GVEA response:
   Please see response to ADEC Comment 11 above, Aaron Simpson of ADEC and Courtney Kimball of SLR (a GVEA consultant) discussed flue gas recirculation during a phone call on November 30, 2017. The North Pole facility does not have any diesel-fired boilers. Mr. Simpson indicated that his comment was meant to address the diesel-fired boilers at the Zehnder facility (EUs 10 and 11). Mr. Simpson and Ms. Kimball agreed that while Flue Gas Recirculation (FGR) is an available emission control technology, vendor information indicates that boiler efficiency would decrease as a result of FGR use. This information is provided in Section 3.2.3 of the Zehnder BACT analysis report. Upon further review of this section of the report, Mr. Simpson stated that no further response to this question was necessary for ADEC Comment 11. GVEA defers to this conversation in response to this comment.

3. Basis for Costs and Assumptions – Documents cited in the analyses which form the basis for costs used in the analyses and assumptions made in the analyses must be provided. For example, within the analysis of SCR for the North Pole facility (see page 30), many of the costs used for SCR appear to be based either on "past project experience" or "information from other projects". Detailed information forming the basis for these cost assumptions in the analysis must be submitted as part of the BACT analysis. Certain other costs are estimated based on a 1993 EPA document referred to as the "Alternative Control Techniques Document". A copy of this document must be included as an attachment to the analysis if this document forms the basis for information used in the analysis. EPA Region 10 will conduct a more detailed review of the calculations following submittal of this and other requested information.

   GVEA response:
   GVEA believes providing cost estimate elements based on "past project experience" or "information from other projects" without providing detailed information is appropriate for this BACT analysis, and is commensurate with an acceptable level of engineering study and cost. Stanley Consultants Inc. (SCI), is a multi-disciplinary engineering company that has provided decades of service to the power generation industry. Services that include new plant design and upgrades and retrofits. SCI assisted in the gathering of engineering estimates, vendor estimates, and did supply information based on their previous project experience. Providing additional detail would require additional time and expense and GVEA is concerned that is may not be warranted pending results from

ADEC about the modeled impacts that NO_x emissions may or may not be having on actual ambient $PM_{2.5}$ concentrations.

The 1993 EPA Alternative Control Techniques Document is specifically cited in the References section (immediately following Section 6) of the North Pole BACT Analysis Report. The document is available on the EPA website[8] and has been supplied with other files on the included DVD-ROM

4. EPA Cost Spreadsheets – Note that the EPA has recently updated the cost manual chapter pertaining to SCR, and developed a cost spreadsheet to be used for evaluation of this technology for cost effectiveness. The EPA spreadsheet was developed to evaluate cost effectiveness of SCR as applied to boilers, so cannot be directly applied to turbines. However, the cost analyses for SCR developed for the GVEA emission units must be consistent with the updated cost manual chapter.

GVEA response:
The NO_x BACT analyses for SCR do not incorporate the November 2017 changes to Section 4, Chapter 2 of the EPA Control Cost Manual (which was posted to the EPA website in December 2017) because EPA issued those changes after the BACT analysis reports were submitted to ADEC. The August 2017 submittal was prepared to be consistent with the previous version. GVEA is aware that interest rates were modified and lowered from 7 percent to 4.25 percent, however in the short time allowed to prepare these responses has not modified the reports and the analyses to reflect this change.

5. SCR Space Constraints – The North Pole analysis includes a number of statements regarding space constraints and other installation challenges that the analysis claims complicate or possibly preclude installation of SCR on the turbines, however detailed drawings, site plans and other information have not been submitted to substantiate these claims. One aerial photo of the facility has been included, but all areas surrounding the buildings housing the emission units are marked as unavailable due to "maintenance access areas" or "fuel delivery truck route". Establishing the entire area surrounding the buildings as unavailable for control equipment based on these purposes would require substantially more detailed justification than has been provided. Additionally, in order to establish SCR as not technically feasible due to space constraints or other retrofit factors, detailed site specific information must be submitted in order to establish the basis for such a determination. Installation factors which would complicate the retrofit installation of the control technology should be evaluated by a qualified control equipment vendor and be reflected in a site-specific capital equipment purchase cost and site specific installation cost estimate or quote. Lacking site-specific cost information, all factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor.

[8] https://www3.epa.gov/ttncatc1/dir1/gasturb.pdf

GVEA response:

As stated in the BACT analyses and intended to be demonstrated on the aerial photographs, GVEA is very concerned with space constraints at both the Zehnder and North Pole sites. This concern is born from our experience in operating and maintaining the units, and maneuvering on the property. The stacks for EU ID's 1 and 2 are split, each having exits on the south and north sides of the building, there is a high voltage substation to the south, and the blue lines represent the circular routes fuel tanker trucks travel to deliver fuel in the most efficient cycle. Marked maintenance areas include access locations for the use of cranes. GVEA believes it would take a very detailed and expensive engineering effort to fully determine the feasibility and cost of SCR installation on EU ID's 1 and 2, and has difficulty justifying that effort until additional information is available from ADEC about the modeled impacts that NO_x emissions may or may not be having on actual ambient $PM_{2.5}$ concentrations. It is very difficult, if not impossible, to gain detailed evaluations and site specific installation estimates from equipment vendors without significant investment.

6. Costs Not Included – In several locations (i.e., p. 40 of the North Pole analysis), the analyses include the statement that cost estimates are "conservatively low" because they do not include the cost of support systems needed to operate the control equipment. EPA Region 10 believes these costs should be included in the analyses, based on site-specific capital and installation estimates or quotes provided by qualified control equipment vendors. Justification for inclusion of each retrofit-related cost must be included in the analyses. Development of reasonably accurate cost estimates for these retrofit projects is necessary in order to inform the BACT determination for each emission unit and pollutant.

GVEA response:

GVEA made every effort to include as many of the support system costs as possible within the scope of this project, however without more detailed and costly engineering and vendor estimates not all equipment is estimated. When available vendor quotes were included. As presented in the separately submitted package under request for confidentiality, recent project incurred costs were apportioned to include reagent preparation equipment. As much available information as possible was gathered, balancing time and expense.

7. Potential vs. Actual Emissions – In some places, the analyses propose BACT determinations based on use of actual emissions. All BACT cost effectiveness calculations must use potential-to emit (PTE), regardless of the emission unit usage history or actual historical emission rates. The facility should consider operating limits in cases where certain emission units do not need to retain relatively high PTE for facility operational purposes.

GVEA response:

Please see response to ADEC Comment 3 above.

In conclusion, GVEA's mission is *to safely provide its member Owners with quality electric service, quality customer service and innovative energy solutions at fair and reasonable prices.* GVEA is committed to being a constructive contributor to improving regional $PM_{2.5}$ concentrations with practical solutions that do not unfairly burden our cooperative members. We recognize that the ultimate path to attainment will be comprised of many smaller contributions, and appeal to ADEC and EPA to work with all stakeholders to find effective and economically viable solutions.

Sincerely,

Nabmi Motton Knight, P.E.
Environmental Health & Safety Officer

Attachments/Enclosures:
Tables 2-1 through 2-4
DVD Disk

cc: Aaron Simpson, ADEC/Air Quality

Table 3-1. Dehydrator Power Plant - Suggested BACT Limits Summary

Emission Unit		Fuel	NO_x BACT			PM_{10} BACT[1]			SO_2 BACT		
ID	Description		Description	Emission Rate[2]	Averaging Period[3]	Description	Emission Rate[2]	Averaging Period[3]	Description	Fuel Sulfur Content	Averaging Period[3]
1_3	Simple Cycle Gas Turbines	Fuel Oil	Good Combustion Practices (existing)	0.94 lb/MMBtu	4 hour block	Good Combustion Practices (existing)	0.033 lb/MMBtu	4 hour block	Fuel Oil and Good Combustion Practices (existing)	0.5 wt. pct. S	4 hour block
3,4	Generator Engines	Diesel	Turbocharger and Aftercooler + Limited Operation (existing)	0.024 lb/hp-hr[4]	4 hour block	Limited Operation (existing)	0.1 lb/MMBtu	4 hour block	Fuel Oil and Good Combustion Practices (existing)	0.5 wt. pct. S	4 hour block
10, 11	Boilers	Diesel	Good Combustion Practices (existing)	20 lb/kgal	4 hour block	Good Combustion Practices (existing)	2.13 lb/kgal	4 hour block	ULSD	0.0015 wt. pct. S	4 hour block

Notes:

[1] CVEA provided direct PM_{10} emissions in the analysis even though Dehydrator Power Plant is not a Serious Nonattainment Area major source for direct PM_{10} emissions. A BACT analysis is not required for this air pollutant.

[2] Emissions are on a per unit basis.

[3] The averaging period is not an indication of compliance demonstration methodology. In some cases, compliance is adequately demonstrated using operating and maintenance records or fuel sulfur content reports.

[4] The NO_x emission factor for EUs 3 and 4 that was provided in Table 3-15 of the Dehydrator BACT analysis report is incorrect. The correct NO_x emission factor is 0.024 lb/hp-hr (3.2 lb/MMBtu of fuel input) consistent with Table 1-3 of the report. The calculations in Section 3 of that report are correctly based on the NO_x emission factor of 0.024 lb/hp-hr.

Table 3-5. North Pole Power Plant - Suggested BACT Limits Summary

Emission Unit		Fuel	NO_x BACT			PM_{10} BACT			SO_2 BACT [3]		
ID	Description		Description	Emission Rate [1]	Averaging Period [2]	Description	Emission Rate [1]	Averaging Period [2]	Description	Emission Rate [1]	Averaging Period [2]
1	Simple Cycle Gas Turbine	Fuel Oil	Limited Operation (existing)	0.58 lb/MMBtu	4 hour block	Good Combustion Practices (existing)	0.12 lb/MMBtu	4 hour block	Good Combustion Practices (existing)	500 ppm S in fuel	4 hour block
2	Simple Cycle Gas Turbine	Fuel Oil	Limited Operation (existing)	0.58 lb/MMBtu	4 hour block	Good Combustion Practices (existing)	0.12 lb/MMBtu	4 hour block	Good Combustion Practices (existing)	500 ppm S in fuel	4 hour block
8,9	Combined Cycle Gas Turbine	LSR	Water Injection (existing)	0.24 lb/MMBtu	4 hour block	Good Combustion Practices (existing)	0.12 lb/MMBtu	4 hour block	LSR (existing)	10 ppm S in fuel	4 hour block
7	Emergency Generator Engine	Fuel Oil	Turbocharger and Aftercooler + Limited Operation (existing)	0.031 lb/hp-hr [3]	4 hour block	Limited Operation + Good Combustion Practices (existing)	0.0022 lb/hp-hr	4 hour block	Good Combustion Practices (existing)	500 ppm S in fuel	4 hour block
11,12	Boiler	Propane	Good Combustion Practices (existing)	13 lb/hgal	4 hour block	Low Sulfur Fuel (existing)	0.7 lb/hgal	4 hour block	Low Sulfur Fuel - Propane (existing)	0.0012 lb/hgal	4 hour block

Notes:

[1] Emissions are on a per unit basis.

[2] The averaging period is not an indication of compliance demonstration methodology. In some cases, compliance is adequately demonstrated using operating and maintenance records or fuel sulfur content reports.

[3] The NO_x emission factor for EU7 that was provided in Table 3-23 of the North Pole BACT analysis report is incorrect. The correct NO_x emission factor is 0.031 lb/hp-hr (0.41 lb/MMBtu of heat input), consistent with Table 1-3 of the report. The calculations in Section 3 of that report are correctly based on the NO_x emission factor of 0.031 lb/hp-hr.

Table 3-3. Zehnder Power Plant - Suggested Startup, Shutdown, and Malfunction BACT Limits Summary

Emission Unit		Startup, Shutdown, and malfunction (SSM) BACT for All Air Pollutants		
ID	Description	Startup	Shutdown	Malfunction
1, 2	Simple Cycle Gas Turbines	Reach stable operation within 30 minutes of initiating startup	Complete shutdown within 15 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.
3,4	Generator Engines	Reach stable operation within 15 minutes of initiating startup	Complete shutdown within 10 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.
10, 11	Boilers	Reach stable operation within 15 minutes of initiating startup	Complete shutdown within 10 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.

Table 2-4. North Pole Power Plant - Suggested Startup, Shutdown, and Malfunction BACT Limits Summary

Emission Unit		Startup, Shutdown, and malfunction (SSM) BACT for All Air Pollutants		
ID	Description	Startup	Shutdown	Malfunction
1	Simple Cycle Gas Turbine	Reach stable operation within 30 minutes of initiating startup	Complete shutdown within 15 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.
2	Simple Cycle Gas Turbine	Reach stable operation within 30 minutes of initiating startup	Complete shutdown within 15 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.
5,6	Combined Cycle Gas Turbine	Reach stable operation within 30 minutes of initiating startup	Complete shutdown within 15 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.
7	Emergency Generator Engine	Reach stable operation within 15 minutes of initiating startup	Complete shutdown within 10 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.
11,12	Boiler	Reach stable operation within 15 minutes of initiating startup	Complete shutdown within 10 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.

EPA-453/R-93-007

Alternative Control Techniques Document— NO_x Emissions from Stationary Gas Turbines

Emission Standards Division

U. S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711
January 1993

ALTERNATIVE CONTROL TECHNIQUES DOCUMENTS

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1.0 INTRODUCTION

Congress, in the Clean Air Act Amendments of 1990 (CAAA), amended Title I of the Clean Air Act (CAA) to address ozone nonattainment areas. A new Subpart 2 was added to Part D of Section 103. Section 183(c) of the new Subpart 2 provides that:

> [w]ithin 3 years after the date of the enactment of the CAAA, the Administrator shall issue technical documents which identify alternative controls for all categories of stationary sources of...oxides of nitrogen which emit or have the potential to emit 25 tons per year or more of such air pollutant.

These documents are to be subsequently revised and updated as determined by the Administrator.

Stationary gas turbines have been identified as a category that emits more than 25 tons of nitrogen oxide (NO_x) per year. This alternative control techniques (ACT) document provides technical information for use by State and local agencies to develop and implement regulatory programs to control NO_x emissions from stationary gas turbines. Additional ACT documents are being developed for other stationary source categories.

Gas turbines are available with power outputs ranging from 1 megawatt (MW) (1,340 horsepower [hp]) to over 200 MW (268,000 hp) and are used in a broad scope of applications. It must be recognized that the alternative control techniques and the corresponding achievable NO_x emission levels presented in this document may not be applicable for every gas turbine application. The size and design of the turbine, the operating duty cycle, site conditions, and other site-specific factors must be taken into consideration, and the suitability of an

alternative control technique must be determined on a case-by-case basis.

The information in this ACT document was generated through a literature search and from information provided by gas turbine manufacturers, control equipment vendors, gas turbine users, and regulatory agencies. Chapter 2.0 presents a summary of the findings of this study. Chapter 3.0 presents information on gas turbine operation and industry applications. Chapter 4.0 contains a discussion of NO_x formation and uncontrolled NO_x emission factors. Alternative control techniques and achievable controlled emission levels are included in Chapter 5.0. The cost and cost effectiveness of each control technique are presented in Chapter 6.0. Chapter 7.0 describes environmental and energy impacts associated with implementing the NO_x control techniques.

2.0 SUMMARY

This chapter summarizes the more detailed information presented in subsequent chapters of this document. It presents a summary of nitrogen oxide (NO_x) formation mechanisms and uncontrolled NO_x emission factors, available NO_x emission control techniques, achievable controlled NO_x emission levels, the costs and cost effectiveness for these NO_x control techniques applied to combustion gas turbines, and the energy and environmental impacts of these control techniques. The control techniques included in this analysis are water or steam injection, dry low-NO_x combustors, and selective catalytic reduction (SCR).

Section 2.1 includes a brief discussion of NO_x formation and a summary of uncontrolled NO_x emission factors. Section 2.2 describes the available control techniques and achievable controlled NO_x emission levels. A summary of the costs and cost-effectiveness for each control technique is presented in Section 2.3. Section 2.4 reviews the range of controlled emission levels, capital costs, and cost effectiveness. Section 2.5 discusses energy and environmental impacts.

2.1 NO_x FORMATION AND UNCONTROLLED NO_x EMISSIONS

The two primary NO_x formation mechanisms in gas turbines are thermal and fuel NO_x. In each case, nitrogen and oxygen present in the combustion process combine to form NO_x. Thermal NO_x is formed by the dissociation of atmospheric nitrogen (N_2) and oxygen (O_2) in the turbine combustor and the subsequent formation of NO_x. When fuels containing nitrogen are combusted, this additional source of nitrogen results in fuel NO_x formation. Because most turbine installations burn natural gas or light

distillate oil fuels with little or no nitrogen content, thermal NO_x is the dominant source of NO_x emissions. The formation rate of thermal NO_x increases exponentially with increases in temperature. Because the flame temperature of oil fuel is higher than that of natural gas, NO_x emissions are higher for operations using oil fuel than natural gas.

Uncontrolled NO_x emission levels were provided by gas turbine manufacturers in parts per million, by volume (ppmv). Unless stated otherwise, all emission levels shown in ppmv are corrected to 15 percent O_2. These emission levels were used to calculate uncontrolled NO_x emission factors, in pounds (lb) of NO_x per million British thermal units (Btu) (lb NO_x/MMBtu). Sample calculations are shown in Appendix A. These uncontrolled emission levels and emission factors for both natural gas and oil fuel are presented in Table 2-1

TABLE 2-1. UNCONTROLLED NO_x EMISSION FACTORS FOR GAS TURBINES

Manufacturer	Model No.	Output, MW	NO_x emissions, ppmv, dry and corrected to 15% 0_2		NO_x emissions factor, lb NO_x/MMBtu[a]	
			Natural gas	Distillate oil No. 2	Natural gas	Distillate oil No. 2
Solar	Saturn	1.1	99	150	0.397	0.551
	Centaur	3.3	130	179	0.521	0.658
	Centaur "H"	4.0	105	160	0.421	0.588
	Taurus	4.5	114	168	0.457	0.618
	Mars T12000	8.8	178	267	0.714	0.981
	Mars T14000	10.0	199	NA[b]	0.798	NA[b]
GM/Allison	501-KB5	4.0	155	231	0.622	0.849
	570-KA	4.9	101	182	0.405	0.669
	571-KA	5.9	101	182	0.405	0.669
General Electric	LM1600	12.8	144	237	0.577	0.871
	LM2500	21.8	174	345	0.698	1.27
	LM5000	33.1	185	364	0.742	1.34
	LM6000	41.5	220	417	0.882	1.53
	MS5001P	26.3	142	211	0.569	0.776
	MS6001B	38.3	148	267	0.593	0.981
	MS7001EA	83.5	154	228	0.618	0.838
	MS7001F	123	179	277	0.718	1.02
	MS9001EA	150	176	235	0.706	0.864
	MS9001F	212	176	272	0.706	1.00
Asea Brown Boveri	GT8	47.4	430	680	1.72	2.50
	GT10	22.6	150	200	0.601	0.735
	GT11N	81.6	390	560	1.56	2.06
	GT35	16.9	300	360	1.20	1.32
Westinghouse	W261B11/12	52.3	220	355	0.882	1.31
	W501D5	119	190	250	0.762	0.919
Siemens	V84.2	105	212	360	0.850	1.32
	V94.2	153	212	360	0.850	1.32
	V64.3	61.5	380	530	1.52	1.95
	V84.3	141	380	530	1.52	1.95
	V94.3	203	380	530	1.52	1.95

[a]Based on emission levels provided by gas turbine manufacturers, corresponding to rated load at ISO conditions. NO_x emissions calculations are shown in Appendix A.

[b]Not available.

. Uncontrolled NO_x emission levels range from 99 to 430 ppmv for natural gas fuel and from 150 to 680 ppmv for distillate oil fuel. Corresponding uncontrolled emission factors range from 0.397 to 1.72 lb NO_x/MMBtu and 0.551 to 2.50 lb NO_x/MMBtu for natural gas and distillate oil fuels, respectively. Because thermal NO_x is primarily a function of combustion temperature, NO_x emission rates vary with combustor design. There is no discernable correlation between turbine size and NO_x emission levels evident in Table 2-1.

2.2 CONTROL TECHNIQUES AND CONTROLLED NO_x EMISSION LEVELS

Reductions in NO_x emissions can be achieved using combustion controls or flue gas treatment. Available combustion controls are water or steam injection and dry low-NO_x combustion designs. Selective catalytic reduction is the only available flue gas treatment.

2.2.1 Combustion Controls

Combustion control using water or steam lowers combustion temperatures, which reduces thermal NO_x formation. Fuel NO_x formation is not reduced with this technique. Water or steam, treated to quality levels comparable to boiler feedwater, is injected into the combustor and acts as a heat sink to lower

flame temperatures. This control technique is available for all new turbine models and can be retrofitted to most existing installations.

Although uncontrolled emission levels vary widely, the range of achievable controlled emission levels using water or steam injection is relatively small. Controlled NO_x emission levels range from 25 to 42 ppmv for natural gas fuel and from 42 to 75 ppmv for distillate oil fuel. Achievable guaranteed controlled emission levels, as provided by turbine manufacturers, are shown for individual turbine models in Figures 2-1 and 2-2

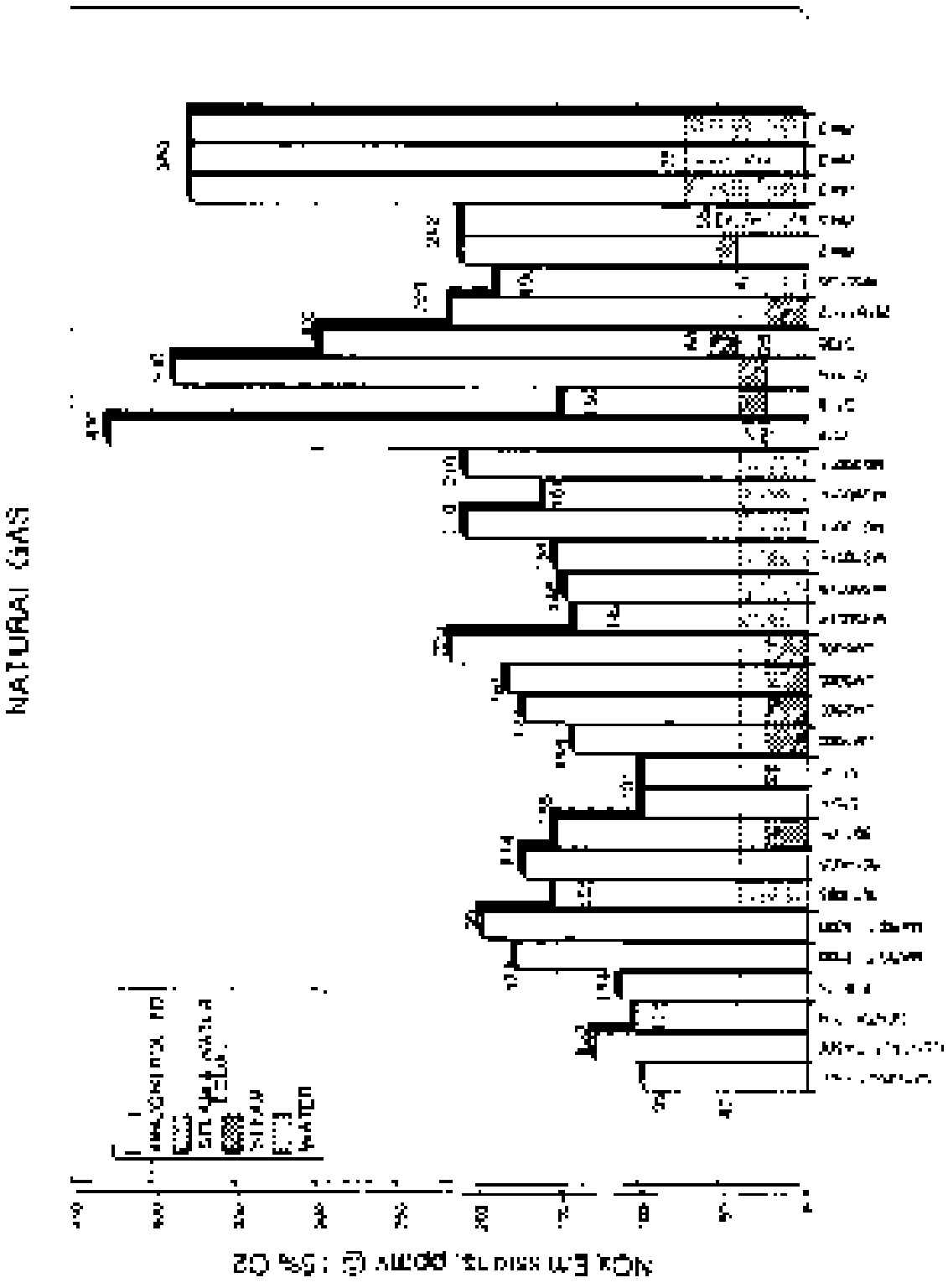


Figure 2-1. **Uncontrolled NOx emission levels and gas turbine manufacturers' guaranteed controlled levels using wet injection. Natural gas fuel.**

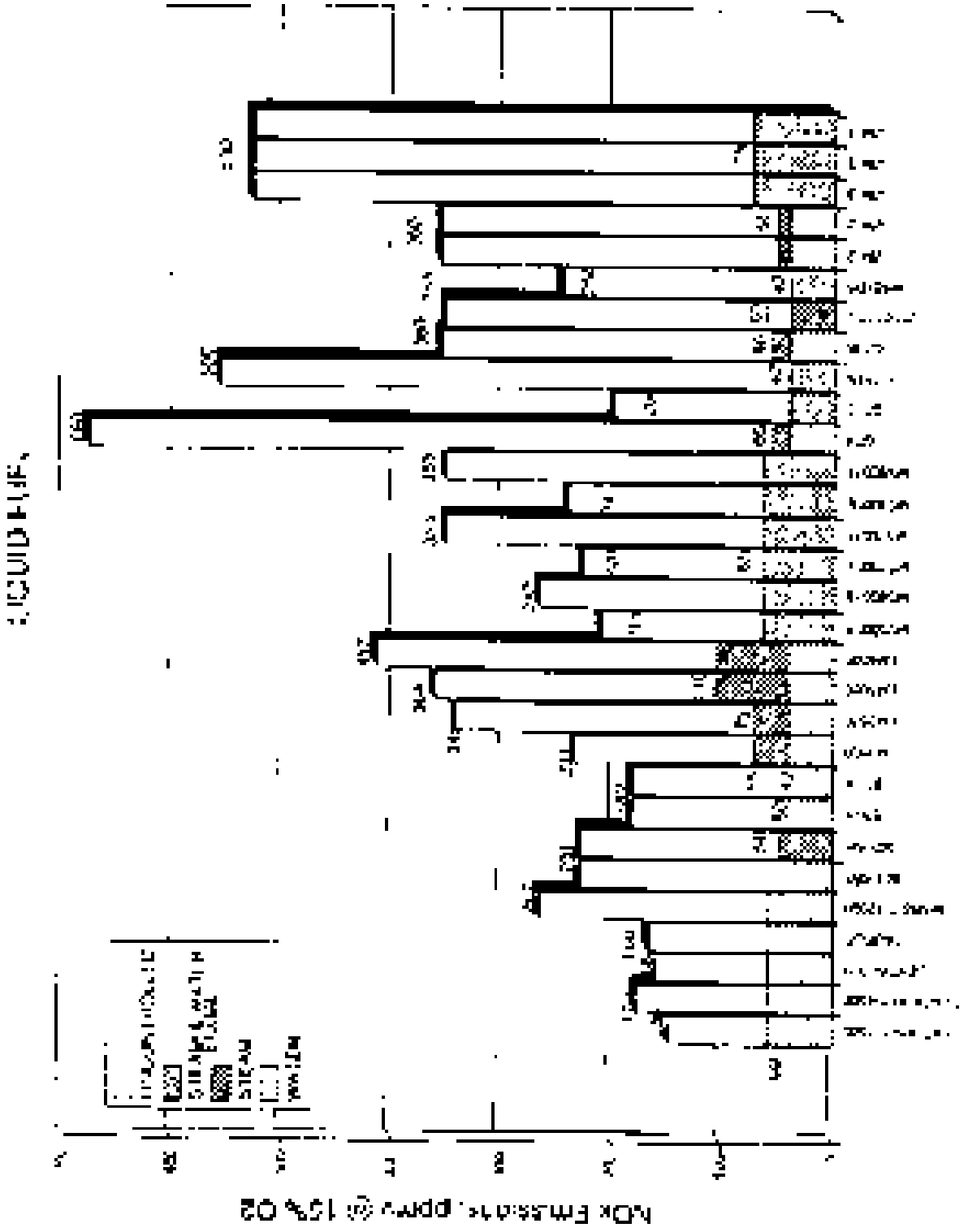


Figure 2-2. **Uncontrolled NO_x emission levels and gas turbine manufacturers' guaranteed controlled levels using wet injection. Distillate oil fuel.**

for natural gas and oil fuels, respectively.

The decision whether to use water versus steam injection for NO_x reduction depends on many factors, including the availability of steam injection nozzles and controls from the turbine manufacturer, the availability and cost of steam at the site, and turbine performance and maintenance impacts. This decision is usually driven by site-specific environmental and economic factors.

A system that allows treated water to be mixed with the fuel prior to injection is also available. Limited testing of water-in-oil emulsions injected into the turbine combustor have achieved NO_x reductions equivalent to direct water injection but at reduced water-to-fuel rates. The vendor reports a similar system is available for natural gas-fired applications.

Dry low-NO_x combustion control techniques reduce NO_x emissions without injecting water or steam. Two designs, lean premixed combustion and rich/quench/lean staged combustion have been developed.

Lean premixed combustion designs reduce combustion temperatures, thereby reducing thermal NO_x. Like wet injection, this technique is not effective in reducing fuel NO_x. In a conventional turbine combustor, the air and fuel are introduced at an approximately stoichiometric ratio and air/fuel mixing occurs simultaneously with combustion. A lean premixed combustor design premixes the fuel and air prior to combustion. Premixing results in a homogeneous air/fuel mixture, which minimizes

localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions. A lean air-to-fuel ratio approaching the lean flammability limit is maintained, and the excess air acts as a heat sink to lower combustion temperatures, which lowers thermal NO_x formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

Lean premixed combustors are currently available from several turbine manufacturers for a limited number of turbine models. Development of this technology is ongoing, and availability should increase in the coming years. All turbine manufacturers state that lean premixed combustors are designed for retrofit to existing installations.

Controlled NO_x emission levels using dry lean premixed combustion range from 9 to 42 ppmv for operation on natural gas fuel. The low end of this range (9 to 25 ppmv) has been limited to turbines above 20 megawatts (MW) (27,000 horsepower [hp]); to date, three manufacturers have guaranteed controlled NO_x emission levels of 9 ppmv at one or more installations for utility-sized turbines. Controlled NO_x emissions from smaller turbines typically range from 25 to 42 ppmv. For operation on distillate oil fuel, water or steam injection is required to achieve controlled NO_x emissions levels of approximately 65 ppmv. Development continues for oil-fueled operation in lean premixed designs, however, and one turbine manufacturer reports having achieved controlled NO_x emission levels below 50 ppmv in limited testing on oil fuel without wet injection.

A second dry low-NO_x combustion design is a rich/quench/lean staged combustor. Air and fuel are partially combusted in a fuel-rich primary stage, the combustion products are then rapidly quenched using water or air, and combustion is completed in a fuel-lean secondary stage. The fuel-rich primary stage inhibits NO_x formation due to low O_2 levels. Combustion temperatures in the fuel-lean secondary stage are below NO_x formation temperatures as a result of the quenching process and the presence of excess air. Both thermal and fuel NO_x are controlled with this design. Limited testing with fuels including natural

gas and coal have achieved controlled NO_x emissions of 25 ppmv. Development of this design continues, however, and currently the rich/quench/lean combustor is not available for production turbines.

2.2.2 Selective Catalytic Reduction

This flue gas treatment technique uses an ammonia (NH_3) injection system and a catalytic reactor to reduce NO_x. An injection grid disperses NH_3 in the flue gas upstream of the catalyst, and NH_3 and NO_x are reduced to N_2 and water (H_2O) in the catalyst reactor. This control technique reduces both thermal NO_x and fuel NO_x.

Ammonia injection systems are available that use either anhydrous or aqueous NH_3. Several catalyst materials are available. To date, most SCR installations use a base-metal catalyst with an operating temperature window ranging from approximately 260° to 400°C (400° to 800°F). The exhaust temperature from the gas turbine is typically above 480°C (900°F), so the catalyst is located within a heat recovery steam generator (HRSG) where temperatures are reduced to a range compatible with the catalyst operating temperature. This operating temperature requirement has, to date, limited SCR to cogeneration or combined-cycle applications with HRSG's to reduce flue gas temperatures. High-temperature zeolite catalysts, however, are now available and have operating temperature windows of up to 600°C (1100°F), which is suitable for installation directly downstream of the turbine. This high-temperature zeolite catalyst offers the potential for SCR applications with simple cycle gas turbines.

To achieve optimum long-term NO_x reductions, SCR systems must be properly designed for each application. In addition to temperature considerations, the NH_3 injection rate must be carefully controlled to maintain an NH_3/NO_x molar ratio that effectively reduces NO_x and avoids excessive NH_3 emissions downstream of the catalyst, known as ammonia slip. The selected catalyst formulation must be resistant to potential masking and/or poisoning agents in the flue gas.

To date, most SCR systems in the United States have been installed in gas-fired turbine applications, but improvements in SCR system designs and experience on alternate fuels in Europe and Japan suggest that SCR systems are suitable for firing distillate oil and other sulfur-bearing fuels. These fuels produce sulfur dioxide (SO_2), which may oxidize to sulfite (SO_3) in the catalyst reactor. This SO_3 reacts with NH_3 slip to form ammonium salts in the low-temperature section of the HRSG and exhaust ductwork. The ammonium salts must be periodically cleaned from the affected surfaces to avoid fouling and corrosion as well as increased back-pressure on the turbine. Advances in catalyst formulations include sulfur-resistant catalysts with low SO_2 oxidation rates. By limiting ammonia slip and using these sulfur-resistant catalysts, ammonium salt formation can be minimized.

Catalyst vendors offer NO_x reduction efficiencies of 90 percent with ammonia slip levels of 10 ppmv or less. These emission levels are warranted for 2 to 3 years, and all catalyst vendors contacted accept return of spent catalyst reactors for recycle or disposal.

Controlled NO_x emission levels using SCR are typically 9 ppmv or less for gas-fueled turbine installations. With the exception of one site, all identified installations operate the SCR system in combination with combustion controls that reduce NO_x emission levels into the SCR to a range of 25 to 42 ppmv. Most continuous-duty turbine installations fire natural gas; there is limited distillate oil-fired operating experience in the United States. Several installations with SCR in the northeast United States that use distillate oil as a back-up fuel have controlled NO_x emission limits of 18 ppmv for operation on distillate oil fuel.

2.3 COSTS AND COST EFFECTIVENESS FOR NO_x CONTROL TECHNIQUES

Capital costs and cost effectiveness were developed for the available NO_x control techniques. Capital costs are presented in Section 2.3.1. Cost-effectiveness figures, in $/ton of NO_x

removed, are shown in Section 2.3.2. All costs presented are in 1990 dollars.

2.3.1 Capital Costs

Capital costs are the sum of purchased equipment costs, taxes and freight charges, and installation costs. Purchased equipment costs were estimated based on information provided by equipment manufacturers, vendors, and published sources. Taxes, freight, and installation costs were developed based on factors recommended in the Office of Air Quality and Planning and Standards Control Cost Manual (Fourth Edition). Capital costs for combustion controls and SCR are presented in Sections 2.3.1.1 and 2.3.1.2, respectively.

2.3.1.1 Combustion Controls Capital Costs. Capital costs for wet injection include a mixed bed demineralizer and reverse-osmosis water treatment system and an injection system consisting of pumps, piping and hardware, metering controls, and injection nozzles. All costs for wet injection are based on the availability of water at the site; no costs have been included for transporting water to the site. These costs apply to new installations; retrofit costs would be similar except that turbine-related injection hardware and metering controls purchased from the turbine manufacturer may be higher for retrofit applications.

The capital costs for wet injection are shown in Figure 2-3, and range from $388,000 for a 3.3 MW (4,430 hp) turbine to $4,830,000 for a 161 MW (216,000 hp) turbine.

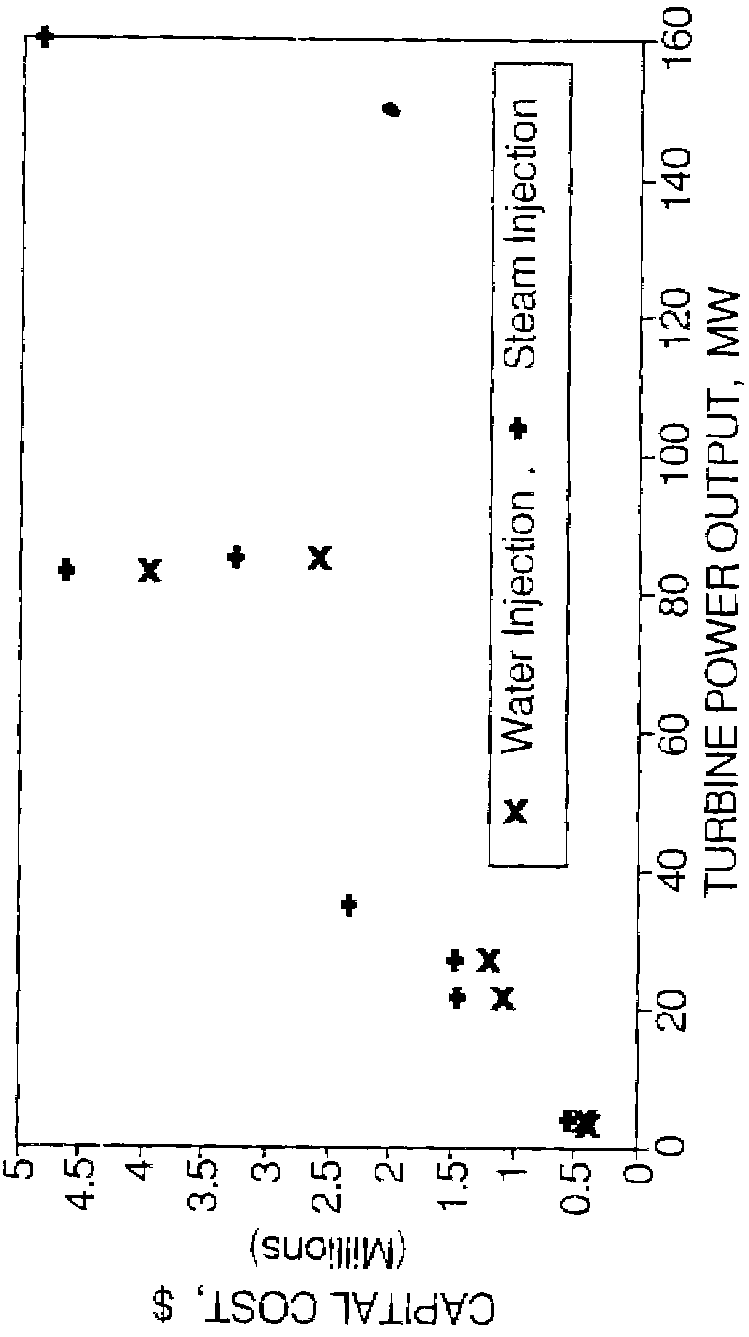


Figure 2-3. Capital costs for water or steam injection.

These capital costs include both water and steam injection systems for use with either gas or distillate oil fuel applications. Figure 2-3 shows that the capital costs for steam injection are slightly higher than those for water injection for turbines in the 3 to 25 MW (4,000 to 33,500 hp) range.

The capital costs for dry low-NO_x combustors are the incremental costs for this design over a conventional combustor and apply to new installations. Turbine manufacturers estimate retrofit costs to be approximately 40 to 60 percent higher than new equipment costs. Incremental capital costs for dry low-NO_x

combustion were provided by turbine manufacturers and are presented in Figure 2-4.

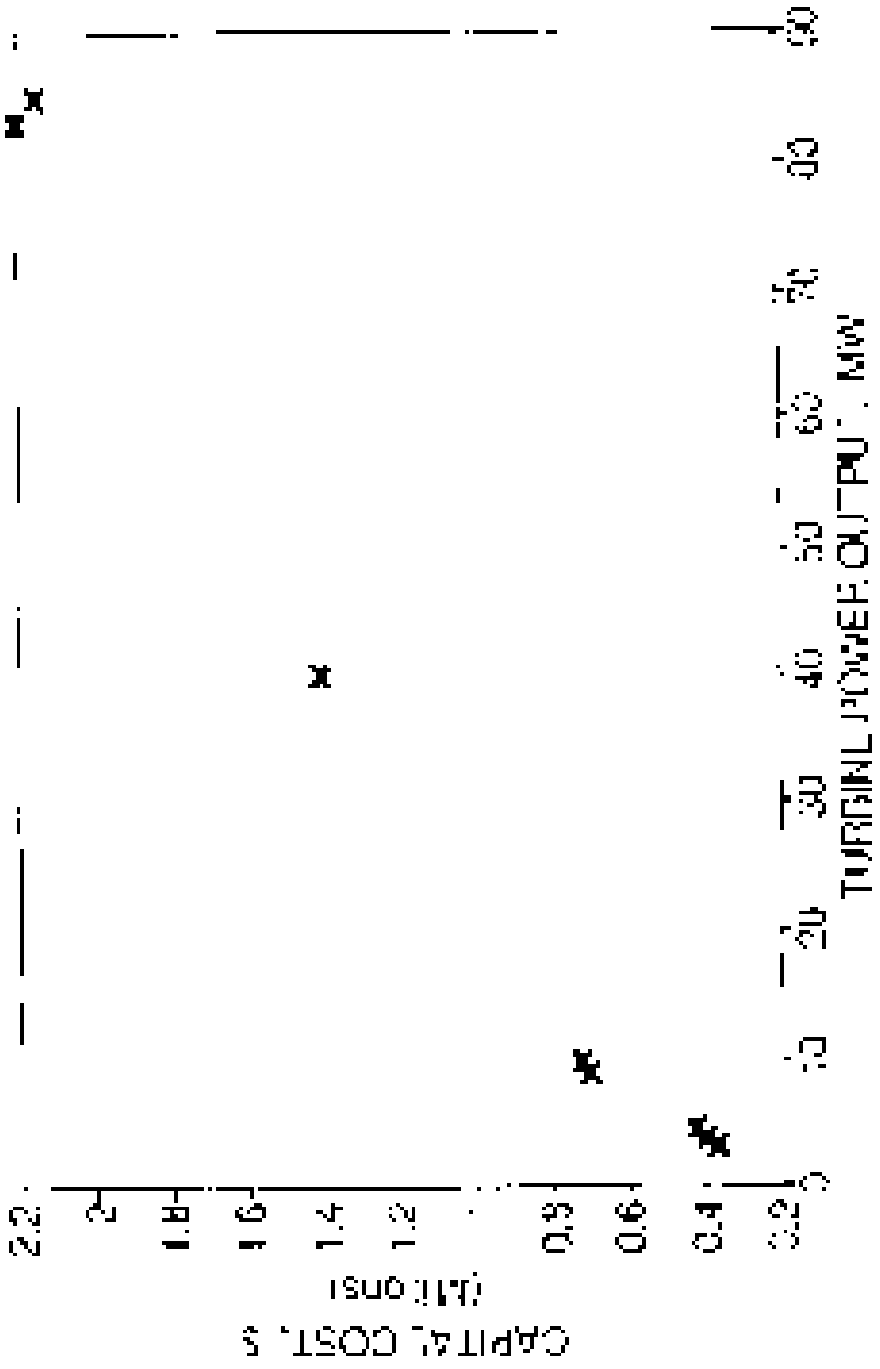


Figure 2-4. Capital costs for dry low-NO_x combustion.

The incremental capital costs range from $375,000 for a 3.3 MW (4,430 hp) turbine to $2.2 million for an 85 MW (114,000 hp) machine. Costs were not available for turbines above 85 MW (114,000 hp).

When evaluated on a $/MW ($/hp) basis, the capital costs for wet injection or dry low-NO_x combustion controls are highest for the smallest turbines and decrease exponentially with increasing turbine size. The range of capital costs for combustion controls, in $/MW, and the effect of turbine size on capital costs are shown in Figure 2-5.

Figure 2-5. Capital costs, in $/MW, for cumbustion controls.

For wet injection, the capital costs range from a high of $138,000/MW ($103/hp) for a 3.3 MW (4,430 hp) turbine to a low of $29,000/MW ($22/hp) for a 161 MW (216,000 hp) turbine. Corresponding capital cost figures for dry low-NO_x combustion range from $114,000/MW ($85/hp) for a 3.3 MW (4,430 hp) unit to $26,000/MW ($19/hp) for an 85 MW (114,000 hp) machine.

2.3.1.2 SCR Capital Costs. Capital costs for SCR include the catalyst reactor, ammonia storage and injection system, and controls and monitoring equipment. A comparison of available cost estimates for base-metal catalyst systems and high-temperature zeolite catalyst systems indicates that the costs for these systems are similar, so a single range of costs was developed that represents all SCR systems, regardless of catalyst type or turbine cycle (i.e., simple, cogeneration, or combined cycle).

The capital costs for SCR, shown in Figure 2-6, range from $622,000 for a 3.3 MW (4,430 hp) turbine to $8.46 million for a 161 MW (216,000 hp) turbine.

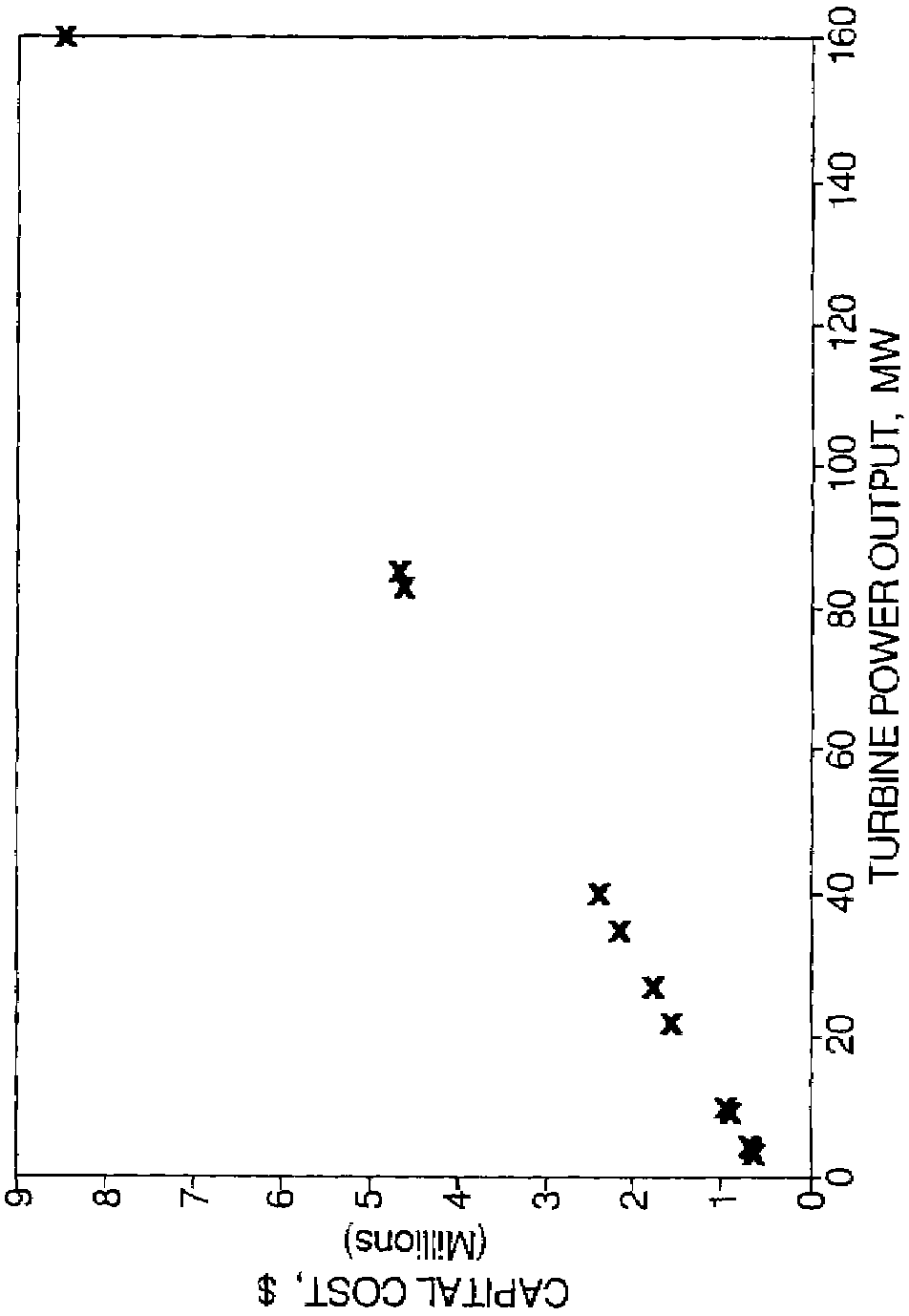


Figure 2-6. Capital costs for selective catalytic reduction.

Figure 2-7 plots capital costs on a $/MW basis and shows that these costs are highest for the smallest turbine, at $188,000/MW ($140/hp) for a 3.3 MW (4,430 hp) unit, and decrease exponentially with increasing turbine size to $52/MW ($40/hp) for a 161 MW (216,000 hp) machine.

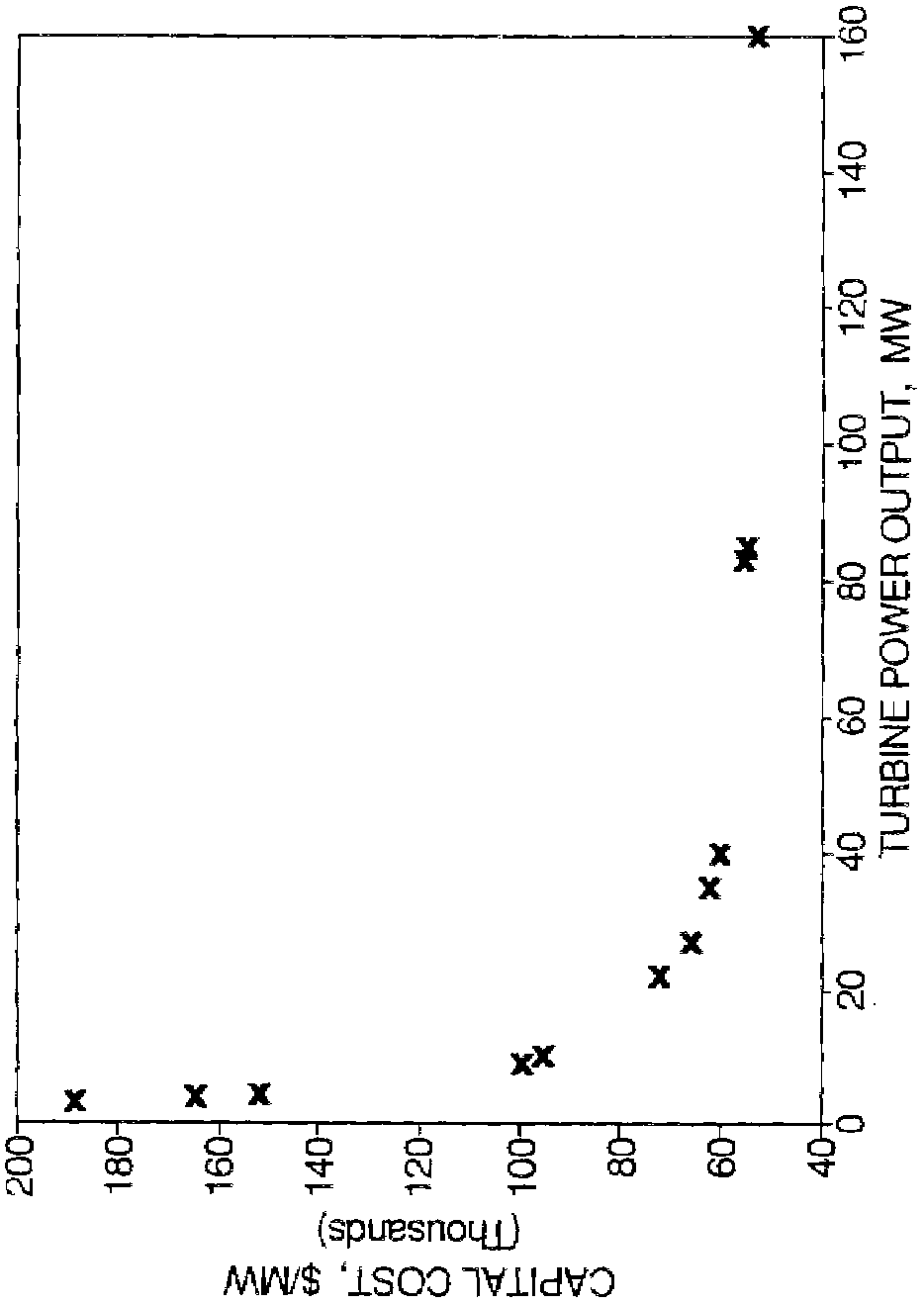


Figure 2-7. Capital costs, in $/MW, for selective catalytic reduction.

These costs apply to new installations firing natural gas as the primary fuel. No SCR sites using oil as the primary fuel were identified, and costs were not available. For this

reason, the costs for gas-fired applications were also used for oil-fired sites. Retrofit SCR costs could be considerably higher than those shown here for new installations, especially if an existing HRSG and ancillary equipment must be moved or modified to accommodate the SCR system.

2.3.2 Cost Effectiveness

The cost effectiveness, in $/ton of NO_x removed, was developed for each NO_x control technique. The cost effectiveness for a given control technique is calculated by dividing the total annual cost by the annual NO_x reduction, in tons. The cost effectiveness presented in this section correspond to 8,000 annual operating hours. Total annual costs were calculated as the sum of all annual operating costs and annualized capital costs. Annual operating costs include costs for incremental fuel, utilities, maintenance, applicable performance penalties, operating and supervisory labor, plant overhead, general and administrative, and taxes and insurance. Capital costs were annualized using the capital recovery factor method with an equipment life of 15 years and an annual interest rate of 10 percent. Cost-effectiveness figures for combustion controls and SCR are presented in Sections 2.3.2.1 and 2.3.2.2, respectively.

2.3.2.1 Combustion Controls Cost Effectiveness. Cost effectiveness for combustion controls is shown in Figure 2-8.

Figure 2-8. Cost effectiveness of combustion controls.

Figure 2-8 indicates that cost effectiveness for combustion controls is highest for the smallest turbines and decreases exponentially with decreasing turbine size. Figure 2-8 also shows that the range of cost effectiveness for water injection is similar to that for steam injection, primarily because the total annual costs and achievable controlled NO_x emission levels for water and steam injection are similar. The cost-effectiveness range for dry low-NO_x combustion is lower than that for wet

$_x$ levels are similar (25 to 42 ppmv), due to the lower total annual costs for dry low-NO_x combustion.

For water injection, cost effectiveness, in $/ton of NO_x removed, ranges from $2,080 for a 3.3 MW (4,430 hp) unit to $575 for an 83 MW (111,000 hp) turbine and $937 for an 85 MW (114,000 hp) turbine. For steam injection, cost effectiveness is $1,830 for a 3.3 MW (4,430 hp), decreasing to $375 for an 83 MW (111,000 hp) turbine, and increasing to $478 for a 161 MW (216,000 hp) turbine. The relatively low cost effectiveness for the 83 MW (111,000 hp) turbine is due to this particular turbine's high uncontrolled NO emissions, which result in a relatively high NO_x removal efficiency and lower cost effectiveness. The cost effectiveness shown in Figure 2-8

number of oil-fired applications with water injection indicates that the cost effectiveness ranges from 70 to 85 percent of the

NO_x removal efficiency achieved in oil-fired applications.

For dry low-NO_x combustion, cost effectiveness, in $/ton of NO_x removed, ranges from $1,060 for a 4.0 MW (5,360 hp) turbine down to $154 for an 85 MW (114,000 hp) machine. A cost effectiveness of $57 was calculated for the 83 MW (111,000 hp) unit. Again, the relatively high uncontrolled NO_x emissions and the resulting high NO_x removal efficiency for this turbine model yields a relatively low cost-effectiveness figure. Current dry low-NO_x combustion designs do not achieve NO_x reductions with oil fuels, so the cost-effectiveness values shown in this section apply only to gas-fired applications.

2.3.2.2 SCR Cost Effectiveness. Cost effectiveness for SCR was calculated based on the use of combustion controls upstream of the catalyst to reduce NO_x emissions to a range of 25 to 42 ppmv at the inlet to the catalyst. This approach was used because all available SCR cost information is for SCR applications used in combination with combustion controls and all but one of the 100+ SCR installations in the United States operate in combination with combustion controls. For this cost analysis, a 5-year catalyst life and a 9 ppmv controlled NO_x emission level was used to calculate cost effectiveness for SCR.

Figure 2-9 presents SCR cost effectiveness. Figure 2-9 shows that, like combustion controls, SCR cost effectiveness is highest for the smallest turbines and decreases exponentially with decreasing turbine size.

Figure 2-9. Cost effectiveness for selective catalytic reduction installed downstream of combustion controls.

Also, because this cost analysis uses a 9 ppmv controlled NO_x emission level for SCR, NO_x reduction efficiencies are higher where the NO_x emission level into the SCR is 42 ppmv than for applications with a 25 ppmv level. Cost effectiveness corresponding to an inlet NO_x emission level of 42 ppmv, in $/ton of NO_x removed, ranges from a high of $10,800 for a 3.3 MW (4430 hp) turbine to $3,580 for a 161 MW (216,000 hp) turbine. For an inlet NO_x emission level of 25 ppmv, the cost-effectiveness range shifts higher, from $22,100 for a 3.3 MW (4,430 hp) installation to $6,980 for an 83 MW (111,000 hp) site.

The range of cost effectiveness for SCR shown in Figure 2-9 applies to gas-fired applications. Cost effectiveness developed for a limited number of oil-fired installations using capital costs from gas-fired applications yields cost-effectiveness values ranging from approximately 70 to 77 percent of those for gas-fired sites. The lower cost-effectiveness figures for oil-fired applications result primarily from the greater annual NO_x reductions for oil-fired applications; the gas-fired capital costs used for these oil-fired applications may understate the actual capital costs for these removal rates and actual oil-fired cost-effectiveness figures may be higher.

Combined cost-effectiveness figures, in $/ton of NO_x removed, were calculated for the combination of combustion controls plus SCR by dividing the sum of the total annual costs by the sum of the NO_x removed for both control techniques. The controlled NO_x emission level for the combination of controls is 9 ppmv. These combined cost-effectiveness figures are presented in Figure 2-10.

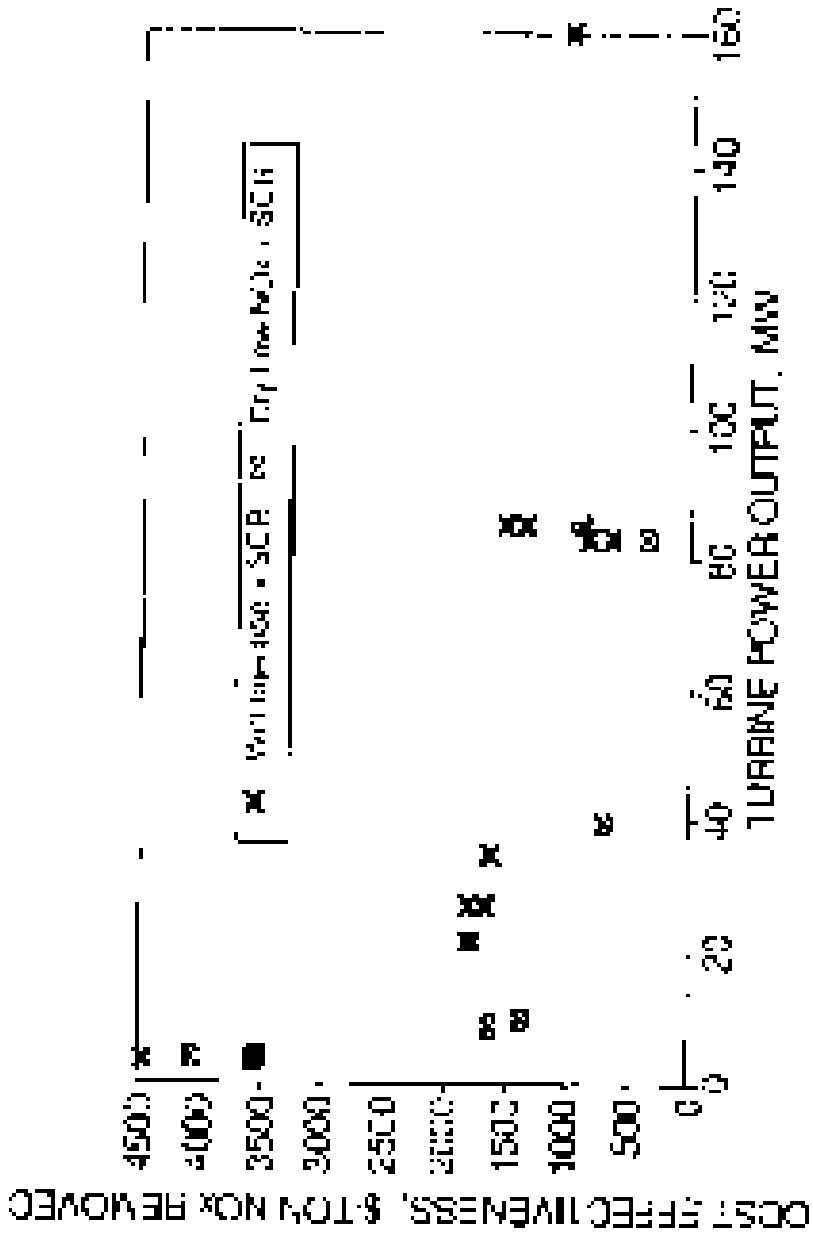


Figure 2-10. Combined cost effectiveness for combustion controls plus selective catalytic reduction.

For wet injection plus SCR, the combined cost effectiveness ranges from $4,460 for a 3.3 MW (4,430 hp) application to $988 for a 160 MW (216,000 hp) site. The $645 cost-effectiveness value for the 83 MW (111,000 hp) turbine is lower than the other turbine models shown in Figure 2-10 due to

the relatively high uncontrolled NO_x emission level for this turbine, which results in relatively high NO_x removal rates and a lower cost effectiveness. For dry low-NO_x combustion plus SCR, combined cost-effectiveness values range from $4,060 to $348 for this turbine size range.

2.4 REVIEW OF CONTROLLED NO_x EMISSION LEVELS AND COSTS

An overview of the performance and costs for available NO_x control techniques is presented in Figure 2-11.

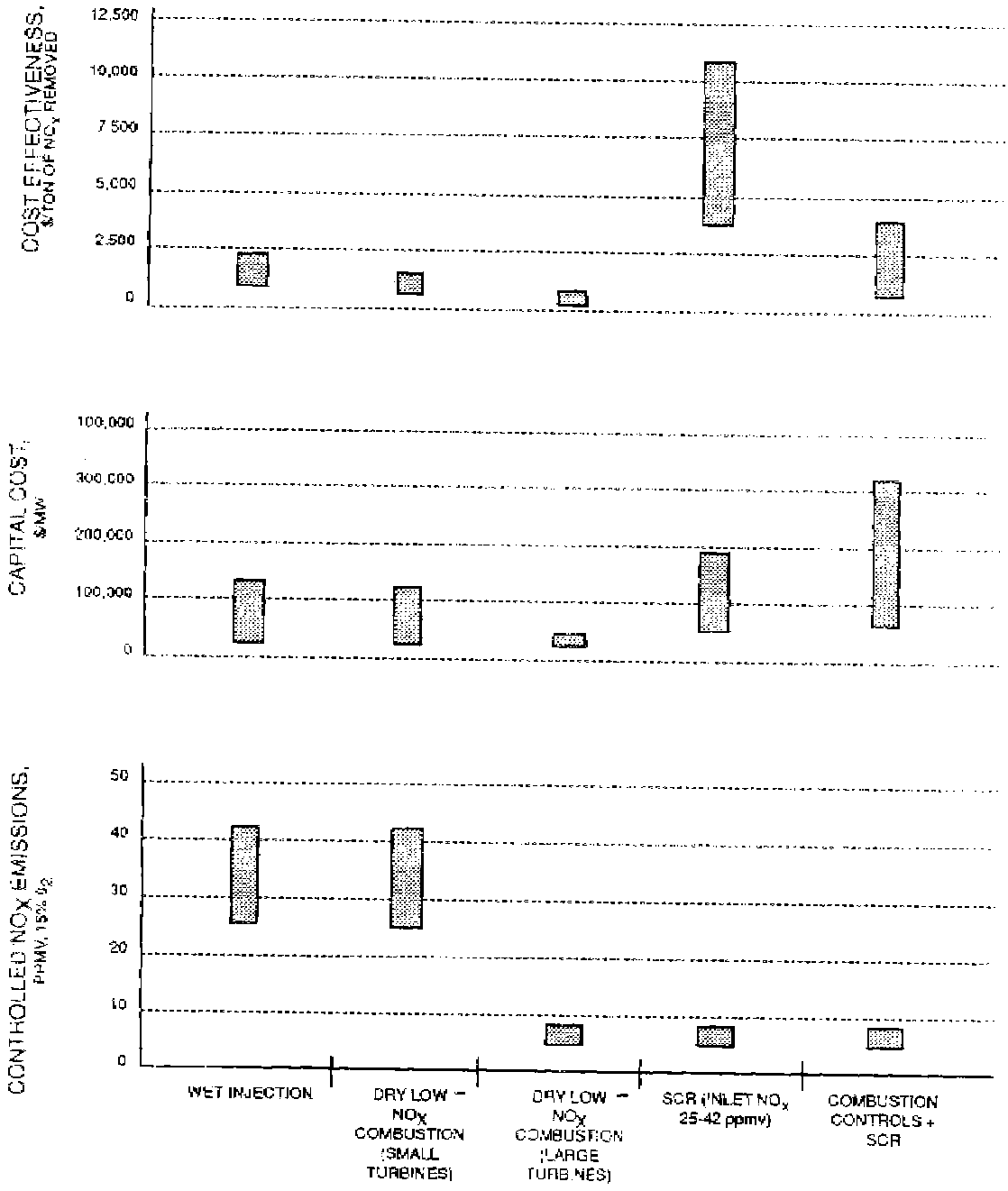


Figure 2-11. Controlled NO_x emission levels and associated capital costs and cost effectiveness for available NO_x control techniques. Natural gas fuel.

Figure 2-11 shows relative achievable controlled NO_x emission levels, capital costs, and cost effectiveness for gas-fired turbine applications. Controlled NO_x emission levels of 25 to 42 ppmv can be achieved using either wet injection or, where available, dry low-NO_x combustion. Wet injection capital costs range from $30,000 to $140,000 per MW ($22 to $104 per hp), and cost effectiveness ranges from $375 to $2,100 per ton of NO_x removed. Dry low-NO_x combustion capital costs range from $25,000 to $115,000 per MW ($19 to $86 per hp), and cost effectiveness ranges from $55 to $1,050 per ton of NO_x removed.

A controlled NO_x emission level of 9 ppmv requires the addition of SCR, except for a limited number of large turbine models for which dry low-NO_x combustion designs can achieve this level. For turbine models above 40 MW (53,600 hp), the capital costs of dry low-NO_x combustion range from $25,000 to $36,000 per MW ($25 to $27 per hp), and the cost effectiveness ranges from $55 to $138 per ton of NO_x removed. Adding SCR to reduce NO_x emission levels from 42 or 25 ppmv to 9 ppmv adds capital costs ranging from $53,000 to $190,000 per MW ($40 to $142 per hp) and yields cost-effectiveness values ranging from $3,500 to $10,500 per ton of NO_x removed. The combination of combustion controls plus SCR yields combined capital costs ranging from $78,000 to $330,000 per MW ($58 to $246 per hp) and cost-effectiveness values ranging from $350 to $4,500 per ton of NO_x removed.

2.5 ENERGY AND ENVIRONMENTAL IMPACTS OF NO_x CONTROL TECHNIQUES

The use of the NO_x control techniques described in this document may affect the turbine performance and maintenance

requirements and may result in increased emissions of carbon monoxide (CO), hydrocarbons (HC), and NH_3. These potential energy and environmental impacts are discussed in this section.

Water or steam injection affects turbine performance and in some turbines also affects maintenance requirements. The increased mass flow through the turbine resulting from water or steam injection increases the available power output. The quenching effect in the combustor, however, decreases combustion efficiency, and consequently the efficiency of the turbine decreases in most applications. The efficiency reduction is greater for water than for steam injection, largely because the heat of vaporization energy cannot be recovered in the turbine. In applications where the steam can be produced from turbine exhaust heat that would otherwise be rejected to the atmosphere, the net gas turbine efficiency is increased with steam injection. Injection of water or steam into the combustor increases the maintenance requirements of the hot section of some turbine models. Water injection generally has a greater impact than steam on increased turbine maintenance. Water or steam injection has the potential to increase CO and, to a lesser extent, HC emissions, especially at water-to-fuel ratios above 0.8.

Turbine manufacturers report no significant performance impacts for lean premixed combustors. Power output and efficiency are comparable to conventional designs. No maintenance impacts are reported, although long-term operating experience is not available. Impacts on CO emissions vary for different combustor designs. Limited data from three manufacturers showed minimal or no increases in CO emissions for controlled NO_x emission levels of 25 to 42 ppmv. For a controlled NO_x level of 9 ppmv, however, CO emissions increased in from 10 to 25 ppmv in one manufacturer's combustor design.

For SCR, the catalyst reactor increases the back-pressure on the turbine, which decreases the turbine power output by approximately 0.5 percent. The addition of the SCR system and associated controls and monitoring equipment increases plant maintenance requirements, but it is expected that these

maintenance requirements are consistent with maintenance schedules for other plant equipment. There is no impact on CO or HC emissions from the turbine caused by the SCR system, but ammonia slip through the catalyst reactor results in NH_3 emissions. Ammonia slip levels are typically guaranteed by SCR vendors at 10 ppmv, and operating experience indicates actual NH_3 emissions are at or below this level.

3.0 STATIONARY GAS TURBINE DESCRIPTION AND INDUSTRY APPLICATIONS

This section describes the physical components and operating cycles of gas turbines and how turbines are used in industry. Projected growth in key industries is also presented.

3.1 GENERAL DESCRIPTION OF GAS TURBINES

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. A common example of a gas turbine is the aircraft jet engine. In stationary applications, the hot combustion gases are directed through one or more fan-like turbine wheels to generate shaft horsepower rather than the thrust propulsion generated in an aircraft engine. Often the heat from the exhaust gases is recovered through an add-on heat exchanger.

Figure 3-1

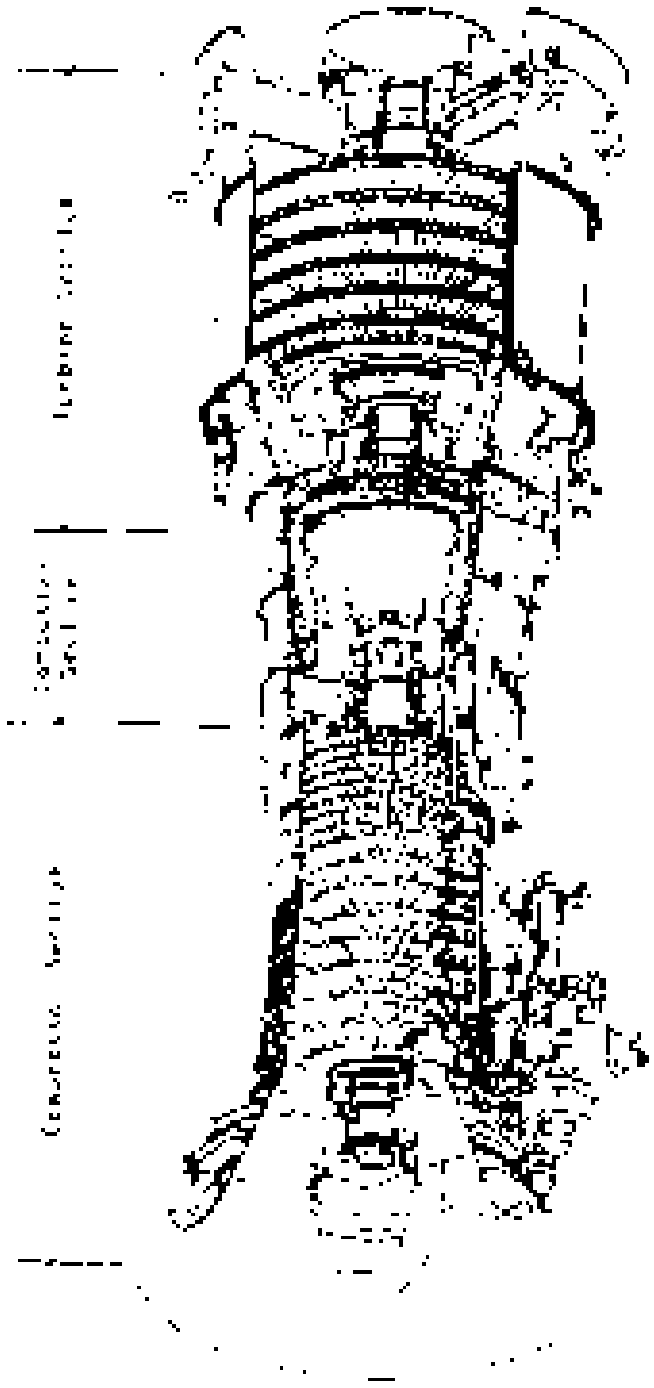


Figure 3-1. The three primary sections of a gas turbine.[1]

presents a cutaway view showing the three primary sections of a gas turbine: the compressor, the combustor, and the turbine.[1] The compressor draws in ambient air and compresses it by a pressure ratio of up to 30 times ambient pressure.[2] The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. There are three types of combustors: annular, can-annular, and silo. An annular combustor is a single continuous chamber roughly the shape of a doughnut that rings the turbine in a plane perpendicular to the air flow. The can-annular type uses a similar configuration but is a series of can-shaped chambers rather than a single continuous chamber. The silo combustor type is one or more chambers mounted external to the gas turbine body. These three combustor types are shown in Figure 3-2

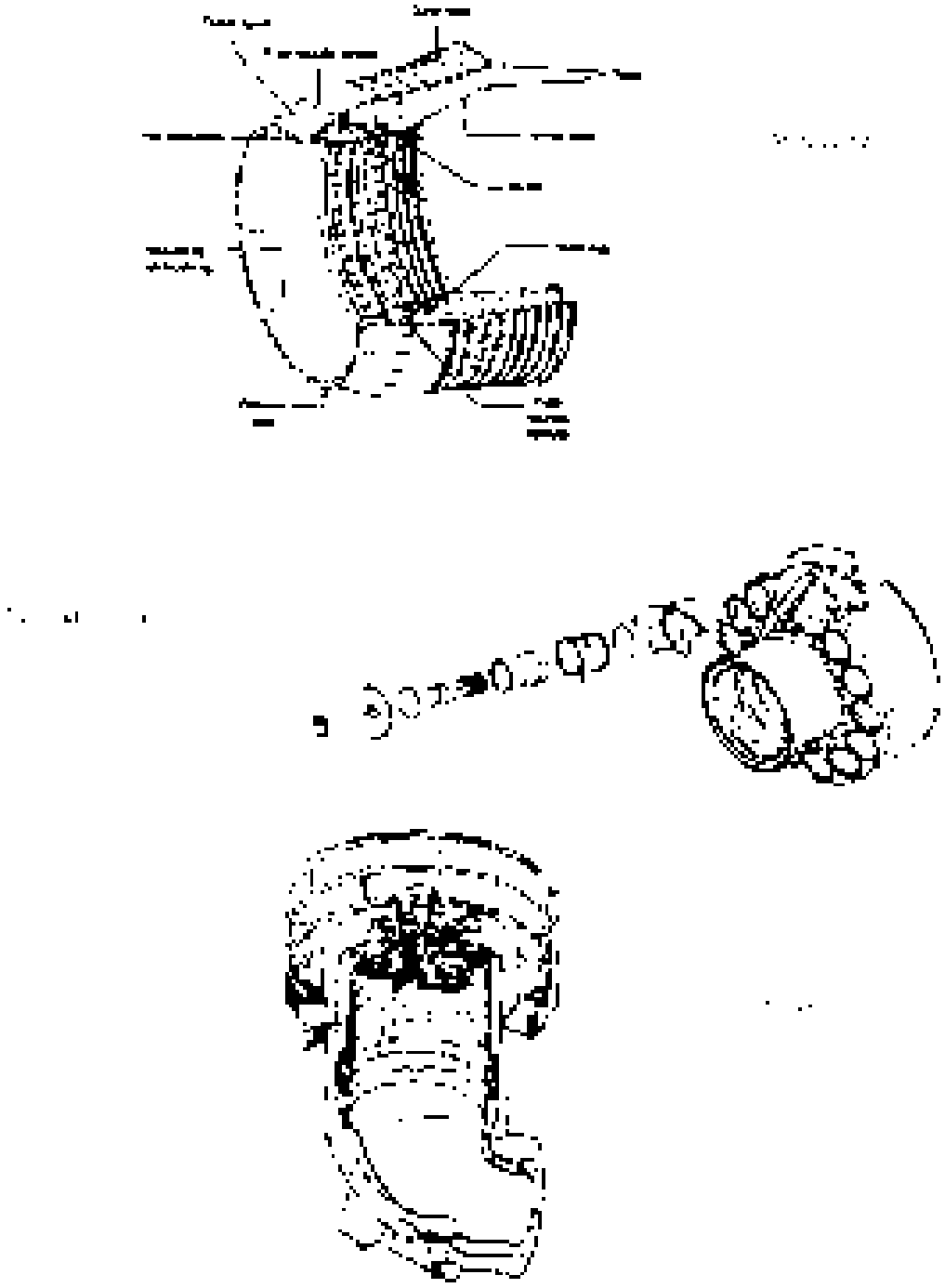
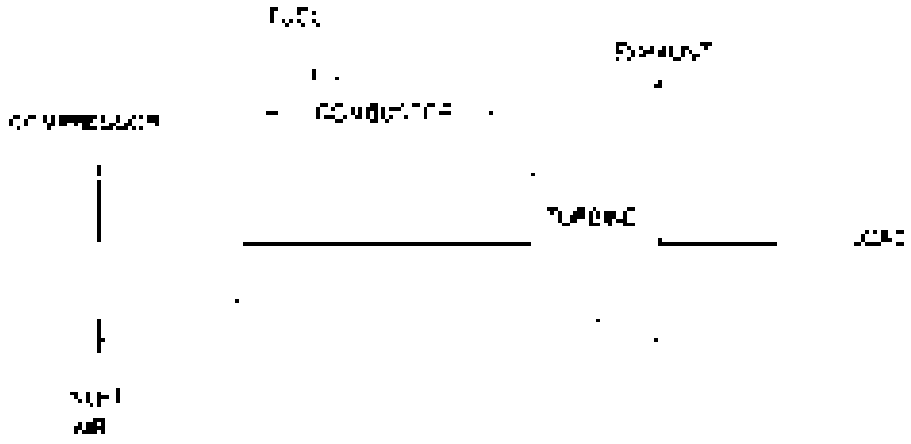


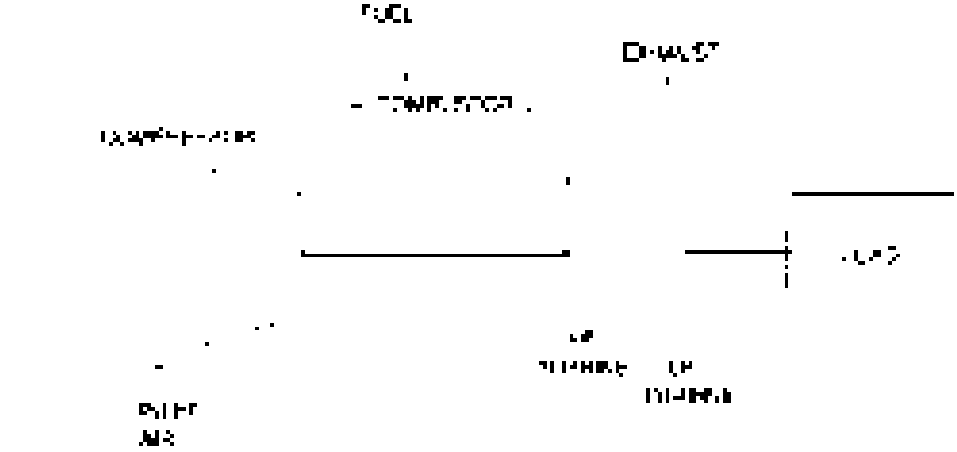
Figure 3-2. Types of gas turbine combustors.[3-5]

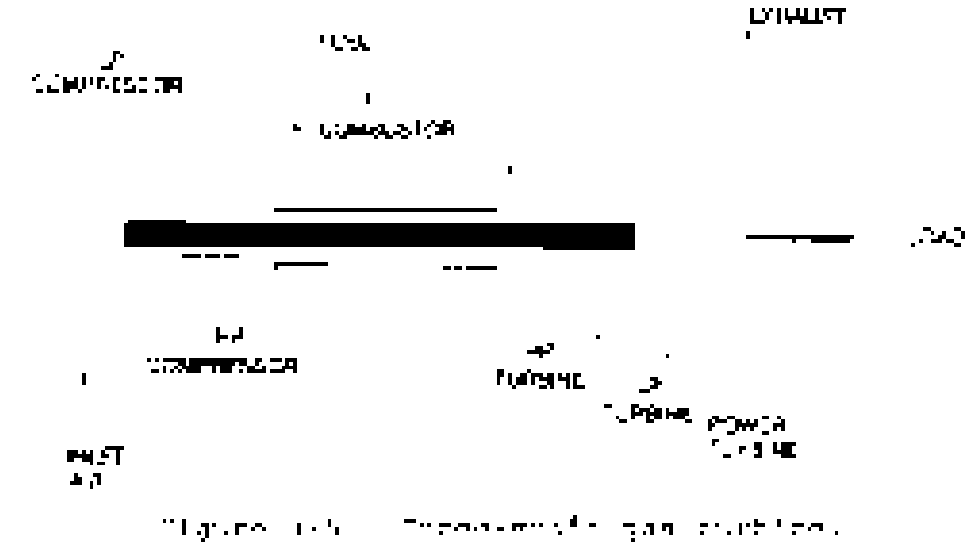
; further discussion of combustors is found in Chapter 5.[3-5] Flame temperatures in the combustor can reach 2000°C (3600°F).[6] The hot combustion gases

are then diluted with additional cool air from the compressor section and directed to the turbine section at temperatures up to 1285°C (2350°F).[6] Energy is recovered in the turbine section in the form of shaft horsepower, of which typically greater than 50 percent is required to drive the internal compressor section.[7] The balance of the recovered shaft energy is available to drive the external load unit.

The compressor and turbine sections can each be a single fan-like wheel assembly, or stage, but are usually made up of a series of stages. In a single-shaft gas turbine, shown in Figure 3-3







, all compressor and turbine stages are fixed to a single, continuous shaft and operate at the same speed. A single-shaft gas turbine is typically used to drive electric generators where there is little speed variation.

A two-shaft gas turbine is shown in Figure 3-4. In this design, the turbine section is divided into a high-pressure and low-pressure arrangement, where the high-pressure turbine is mechanically tied to the compressor section by one shaft, while the low-pressure turbine, or power turbine, has its own shaft and is connected to the external load unit. This configuration allows the high-pressure turbine/compressor shaft assembly, or rotor, to operate at or near optimum design speeds, while the power turbine rotor speed can vary over as wide a range as is required by most external-load units in mechanical drive applications (i.e., compressors and pumps).

A third configuration is a three-shaft gas turbine. As shown in Figure 3-5, the compressor section is divided into a low-pressure and high-pressure configuration. The low-pressure compressor stages are mechanically tied to the low-pressure turbine stages, and the high-pressure compressor stages are similarly connected to the high-pressure turbine stages in a concentric shaft arrangement. These low-pressure and high-pressure rotors operate at optimum design speeds independent of each other. The power turbine stages are mounted on a third independent shaft and form the power turbine rotor, the speed of

which can vary over as wide a range as is necessary for mechanical drive applications.

Gas turbines can burn a variety of fuels. Most burn natural gas, waste process gases, or liquid fuels such as distillate oils (primarily No. 2 fuel oil). Some gas turbines are capable of burning lower-grade residual or even crude oil with minimal processing. Coal-derived gases can be burned in some turbines.

The capacity of individual gas turbines ranges from approximately 0.08 to over 200 megawatts (MW) (107 to 268,000 horsepower [hp]).[2] Manufacturers continue to increase the horsepower of individual gas turbines, and frequently they are "ganged," or installed in groups so that the total horsepower output from one location can meet virtually any installation's power requirements.

Several characteristics of gas turbines make them attractive power sources. These characteristics include a high horsepower-to-size ratio, which allows for efficient space utilization, and a short time from order placement to on-line operation. Many suppliers offer the gas turbine, load unit, and all accessories as a fully assembled package that can be performance tested at the supplier's facility. This packaging is cost effective and saves substantial installation time. Other advantages of gas turbines are:

1. Low vibration;
2. High reliability;
3. No requirement for cooling water;
4. Suitability for remote operation;
5. Lower capital costs than reciprocating engines; and
6. Lower capital costs than boiler/steam turbine-based electric power generating plants.[8]

3.2 OPERATING CYCLES

The four basic operating cycles for gas turbines are simple, regenerative, cogeneration, and combined cycles. Each of these cycles is described separately below.

3.2.1 Simple Cycle

The simple cycle is the most basic operating cycle of a gas turbine. In a simple cycle application, a gas turbine functions with only the three primary sections described in Section 3.1, as depicted in Figure 3-6.

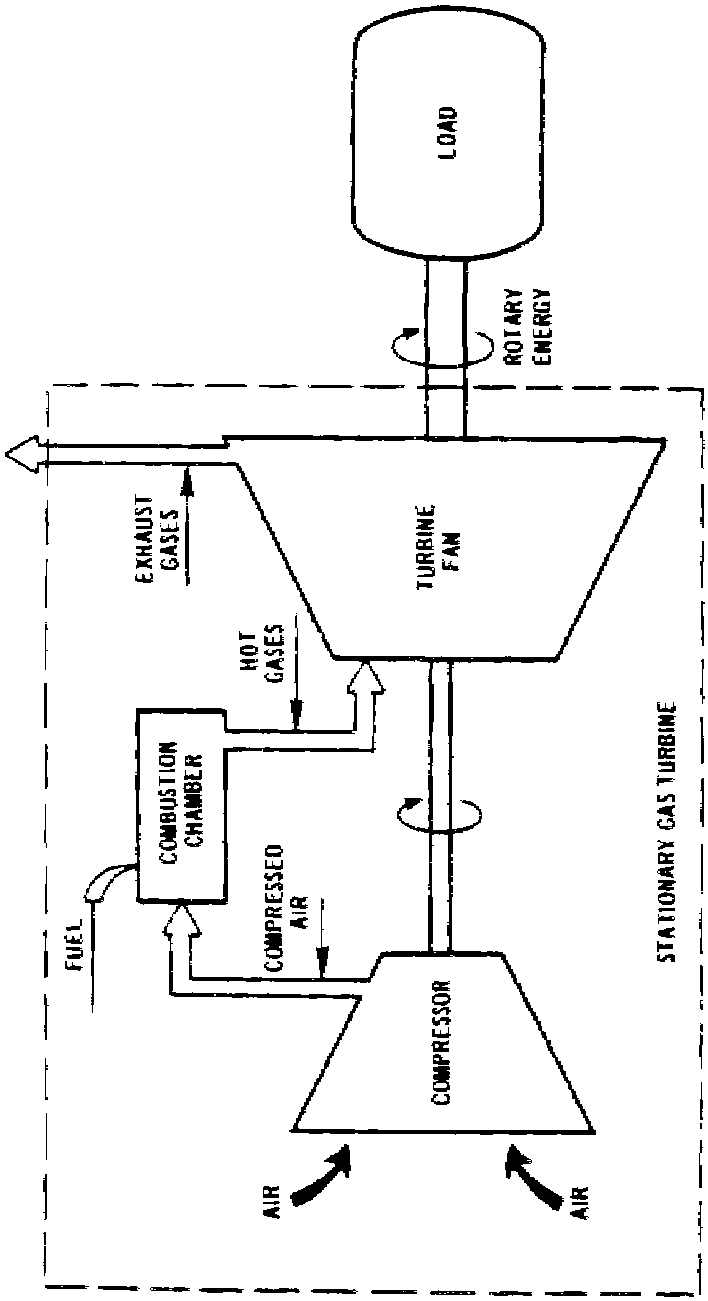


Figure 3-6. Simple cycle gas turbine appplication.[10]

[10] Cycle efficiency, defined as a percentage of useful shaft energy output to fuel energy input, is typically in the 30 to 35 percent range, although one manufacturer states an efficiency of 40 percent for an engine recently introduced to the market.[9] In addition to shaft energy output, 1 to 2 percent of the fuel input energy can be attributed to mechanical losses; the balance is exhausted from the turbine in the form of heat.[7] Simple cycle operation is typically used when there is a requirement for shaft horsepower without recovery of the exhaust heat. This cycle offers the lowest installed capital cost but also provides the least efficient use of fuel and therefore the highest operating cost.

3.2.2 Regenerative Cycle

The regenerative cycle gas turbine is essentially a simple cycle gas turbine with an added heat exchanger, called a regenerator or recuperator, to preheat the combustion air. In the regenerative cycle, thermal energy from the exhaust gases is transferred to the compressor discharge air prior to being introduced into the combustor. A diagram of this cycle is depicted in Figure 3-7

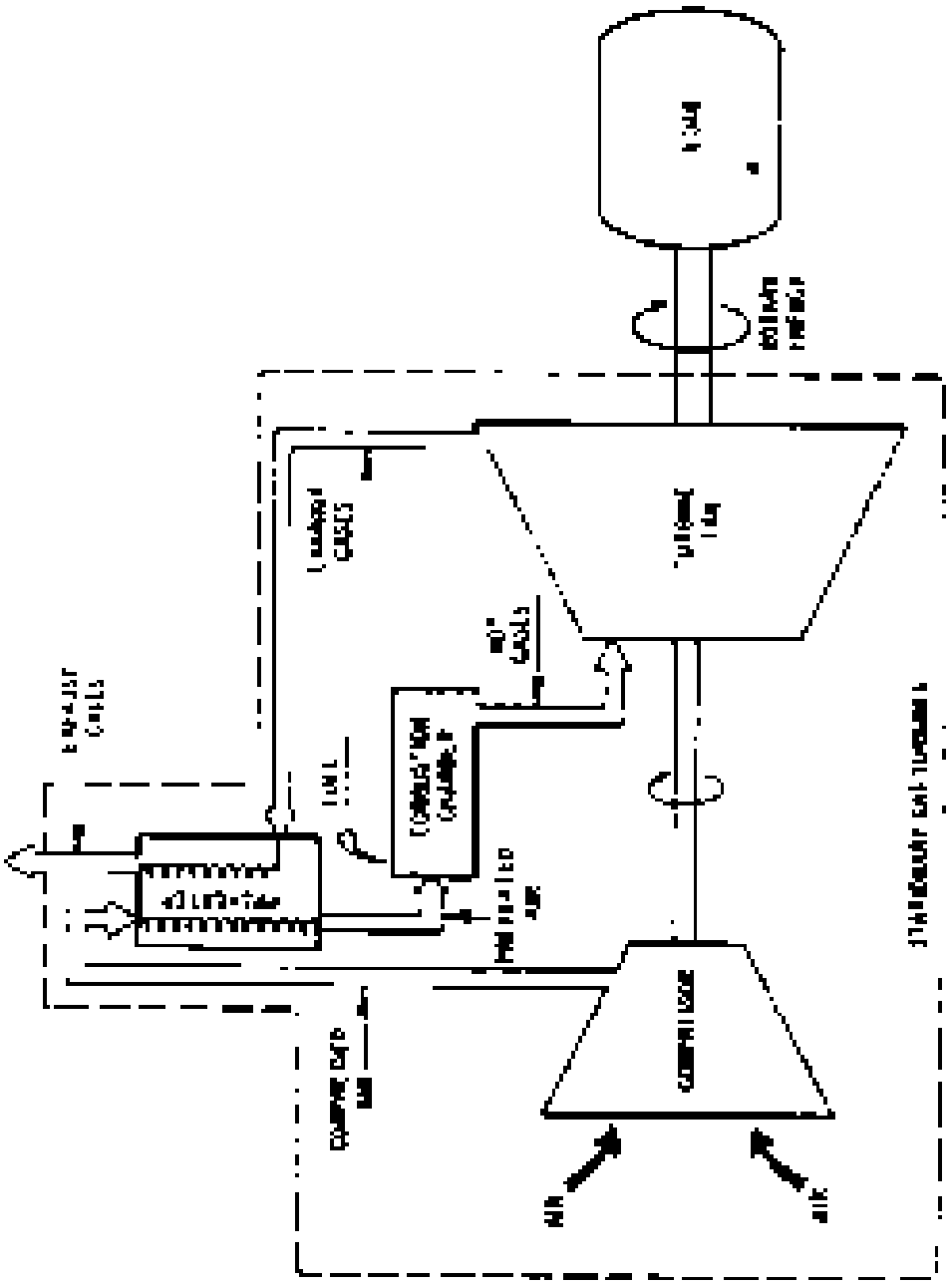


Figure 3-7. Regenerative cycle gas turbine.[11]

.[11] Preheating the combustion air reduces the amount of fuel required to reach design combustor temperatures and therefore improves the overall cycle efficiency over that of simple cycle operation. The efficiency gain is directly proportional to the differential temperature between the exhaust gases and compressor discharge air. Since the compressor discharge air temperature increases with an increase in pressure ratio, higher regenerative cycle efficiency gains are realized from lower compressor pressure ratios typically found in older gas turbine models.[7] Most new or updated gas turbine models with high compressor pressure ratios render regenerative cycle operation economically unattractive because the capital cost of the regenerator cannot be justified by the marginal fuel savings.

3.2.3 Cogeneration Cycle

A gas turbine used in a cogeneration cycle application is essentially a simple cycle gas turbine with an added exhaust heat exchanger, called a heat recovery steam generator (HRSG). This configuration is shown in Figure 3-8

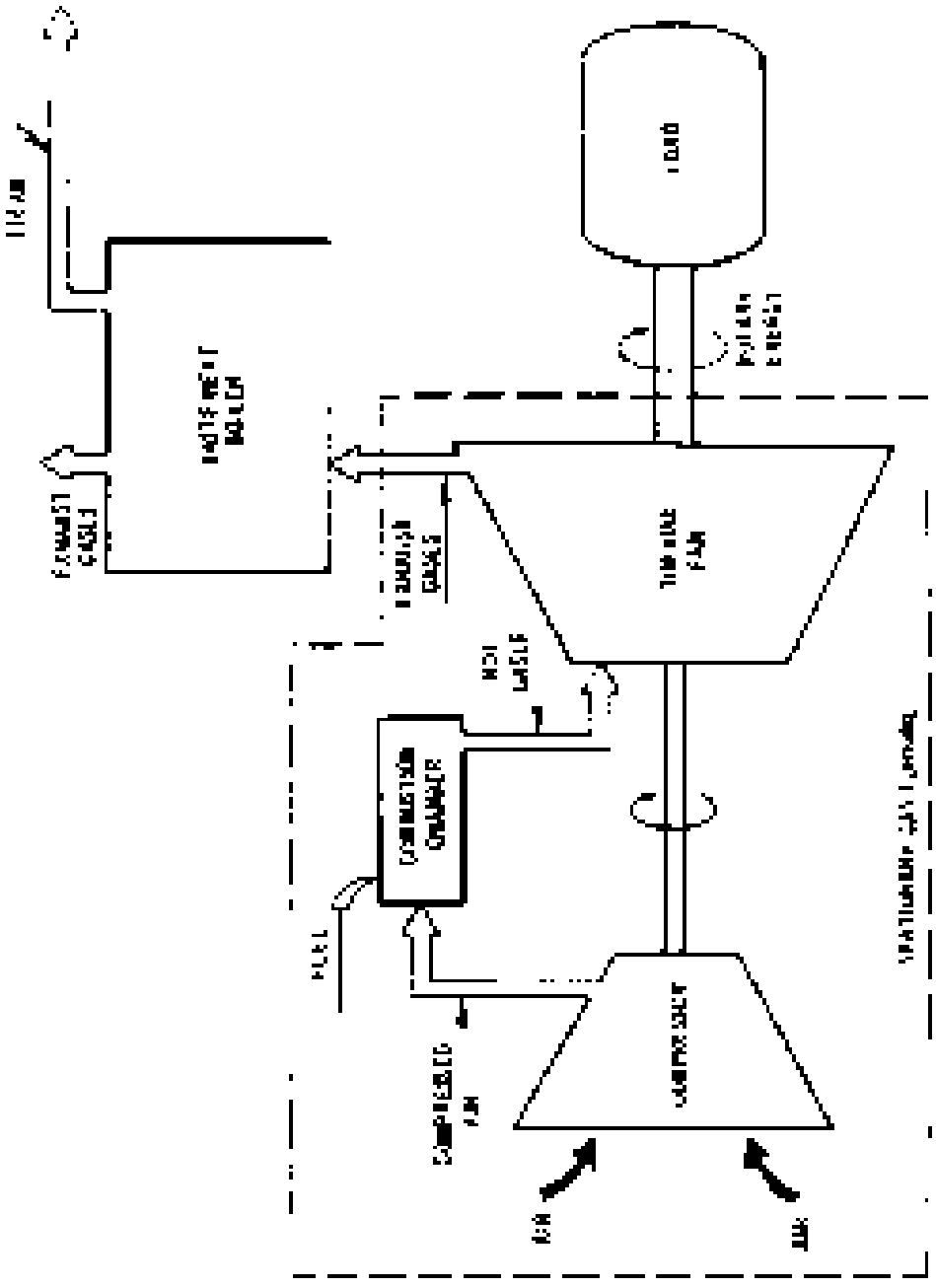


Figure 3-8. Cogeneration cycle gas turbine application.[12]

.[12] The steam generated by the exhaust heat can be delivered at a variety of pressure and temperature conditions to meet site thermal process requirements. Where the exhaust heat is not sufficient to meet site requirements, a supplementary burner, or duct burner, can be placed in the exhaust duct upstream of the HRSG to increase the exhaust heat energy. Adding the HRSG equipment increases the capital cost, but recovering the exhaust heat increases the overall cycle efficiency to as high as 75 percent.[13]

3.2.4 Combined Cycle

A combined cycle is the terminology commonly used for a gas turbine/HRSG configuration as applied at an electric utility. This cycle, shown in Figure 3-9

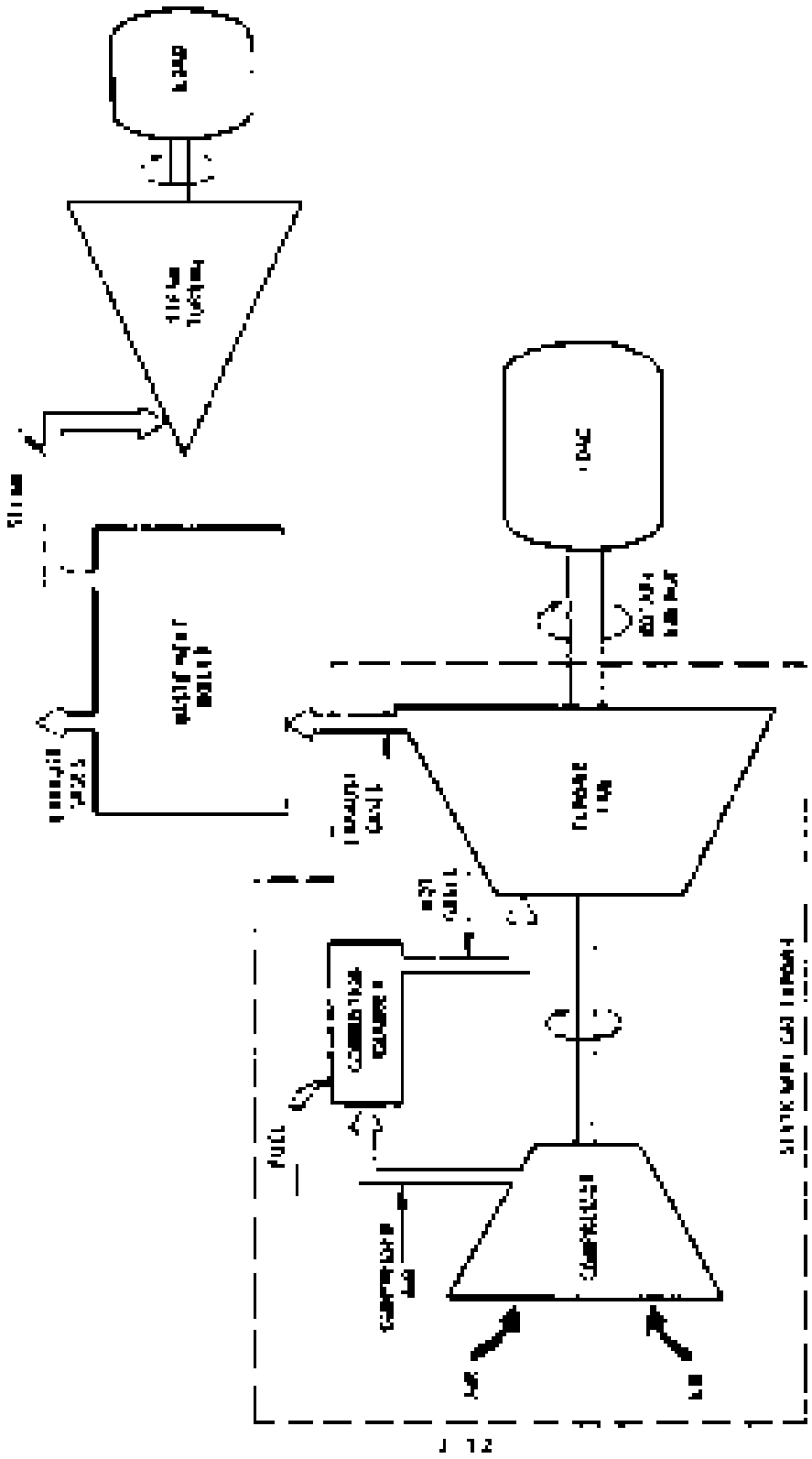


Figure 3-9. Combined cycle gas turbine application.[12]

, is used to generate electric power.[12] The gas turbine drives an electric generator, and the steam produced in the HRSG is delivered to a steam turbine, which also drives an electric generator. The boiler may be supplementary-fired to increase the steam production where desired. Cycle efficiencies can exceed 50 percent.

3.3 INDUSTRY APPLICATIONS

Gas turbines are used by industry in both mechanical and electrical drive applications. Compressors and pumps are most often the driven load unit in mechanical drive applications, and electric generators are driven in electrical drive installations. Few sites have gas/air compression or fluid pumping requirements that exceed 15 MW (20,100 hp), and for this reason mechanical drive applications generally use gas turbines in the 0.08- to 15.0-MW (107- to 20,100-hp) range.[14] Electric power requirements range over the entire available range of gas turbines, however, and all sizes can be found in electrical drive applications, from 0.08 to greater than 200 MW (107 to 268,000 hp).[15]

The primary applications for gas turbines can be divided into five broad categories: the oil and gas industry,

stand-by/emergency electric power generation, independent electric power producers, electric utilities, and other industrial applications.[16] Where a facility has a requirement for mechanical shaft power only, the installation is typically simple or regenerative cycle. For facilities where either electric power or mechanical shaft power and steam generation are required, the installation is often cogeneration or combined cycle to capitalize on these cycles' higher efficiencies.

3.3.1 Oil and Gas Industry

The bulk of mechanical drive applications are in the oil and gas industry. Gas turbines in the oil and gas industry are used primarily to provide shaft horsepower for oil and gas extraction and transmission equipment, although they are also used in downstream refinery operations. Most gas turbines found in this industry are in the 0.08- to 15.0-MW (107- to 20,100-hp) range.

Gas turbines are particularly well suited to this industry, as they can be fueled by a wide range of gaseous and liquid fuels often available at the site. Natural gas and distillate oil are the most common fuels. Many turbines can burn waste process gases, and some turbines can burn residual oils and even crude oil. In addition, gas turbines are suitable for remote installation sites and unattended operation. Most turbines used in this industry operate continuously, 8,000+ hours per year, unless the installation is a pipeline transmission application with seasonal operation.

Competition from reciprocating engines in this industry is significant. Although gas turbines have a considerable capital cost advantage, reciprocating engines require less fuel to produce the same horsepower and consequently have a lower operating cost.[17] Selection of gas turbines vs. reciprocating engines is generally determined by site-specific criteria such as installed capital costs, costs for any required emissions control equipment, fuel costs and availability, annual operating hours, installation and structural considerations, compatibility with existing equipment, and operating experience.

3.3.2 Stand-By/Emergency Electric Power Generation

Small electric generator sets make up a considerable number of all gas turbine sales under 3.7 MW (5,000 hp). The majority of these installations provide backup or emergency power to critical networks or equipment and use liquid fuel. Telephone companies are a principal user, and hospitals and small municipalities also are included in this market. These turbines operate on an as-needed basis, which typically is between 75 and 200 hours per year.

Gas turbines offer reliable starting, low weight, small size, low vibration, and relatively low maintenance, which are important criteria for this application. Gas turbines in this size range have a relatively high capital cost, however, and reciprocating engines dominate this market, especially for applications under 2,000 kW (2,700 hp).[18,19]

3.3.3 Independent Electrical Power Producers

Large industrial complexes and refining facilities consume considerable amounts of electricity, and many sites choose to generate their own power. Gas turbines can be used to drive electric generators in simple cycle operation, or an HRSG system may be added to yield a more efficient cogeneration cycle. The vast majority of cogeneration installations operate in a combined cycle capacity, using a steam turbine to provide additional electric power. The Public Utility Regulatory Policies Act (PURPA) of 1978 encourages independent cogenerators to generate electric power by requiring electric utilities to (1) purchase electricity from qualifying producers at a price equal to the cost the utility can avoid by not having to otherwise supply that power (avoided cost) and (2) provide backup power to the cogenerator at reasonable rates. Between 1980 and 1986, approximately 20,000 MW of gas turbine-produced electrical generating capacity was certified as qualifying for PURPA benefits. This installed capacity by private industry power generators is more than the sum of all utility gas turbine orders for all types of central power plants during this period.[20] The Department of Energy (DOE) expects an additional 27,000 MW

capacity to be purchased by private industry in the next 10 years.[21]

Gas turbines installed in this market range in power from 1 to over 100 MW (1,340 to 134,000 hp) and operate typically between 4,000 and 8,000 hours per year. While reciprocating engines compete with the gas turbine at the lower end of this market (under approximately 7.5 MW [10,000 hp]), the advantages of lower installed costs, high reliability, and low maintenance requirements make gas turbines a strong competitor.

3.3.4 Electric Utilities

Electric utilities are the largest user of gas turbines on an installed horsepower basis. They have traditionally installed these turbines for use as peaking units to meet the electric power demand peaks typically imposed by large commercial and industrial users on a daily or seasonal basis; consequently, gas turbines in this application operate less than 2,000 hours per year.[22] The power range used by the utility market is 15 MW to over 150 MW (20,100 to 201,000 hp). Peaking units typically operate in simple cycle.

The demand for gas turbines from the utility market was flat through the late 1970's and 1980's as the cost of fuel increased and the supplies of gas and oil became unpredictable. There are signs, however, that the utility market is poised to again purchase considerable generating capacity. The capacity margin, which is the utility industry's measure of excess generation capacity, peaked at 30 percent in 1982. By 1990, the capacity margin had dropped to approximately 20 percent, and, based on current construction plans, will reach the industry rule-of-thumb minimum of 15 percent by 1995.[21] The utility industry is adding new capacity and repowering existing older plants, and gas turbines are expected to play a considerable role.

Many utilities are now installing gas turbine-based combined cycle installations with provisions for burning coal-derived gas fuel at some future date. This application is known as integrated coal gasification combined cycle (IGCC). At least five power plant projects have been announced, and several more

are being negotiated. Capital costs for these plants are in many cases higher than comparable natural gas-fueled applications, but future price increases for natural gas could make IGCC an attractive option for the future.[23]

Utility orders for gas turbines have doubled in each of the last 2 years. The DOE says that electric utilities will need to add an additional 73,000 MW to capacity to meet demand by the year 2000, and as Figure 3-10

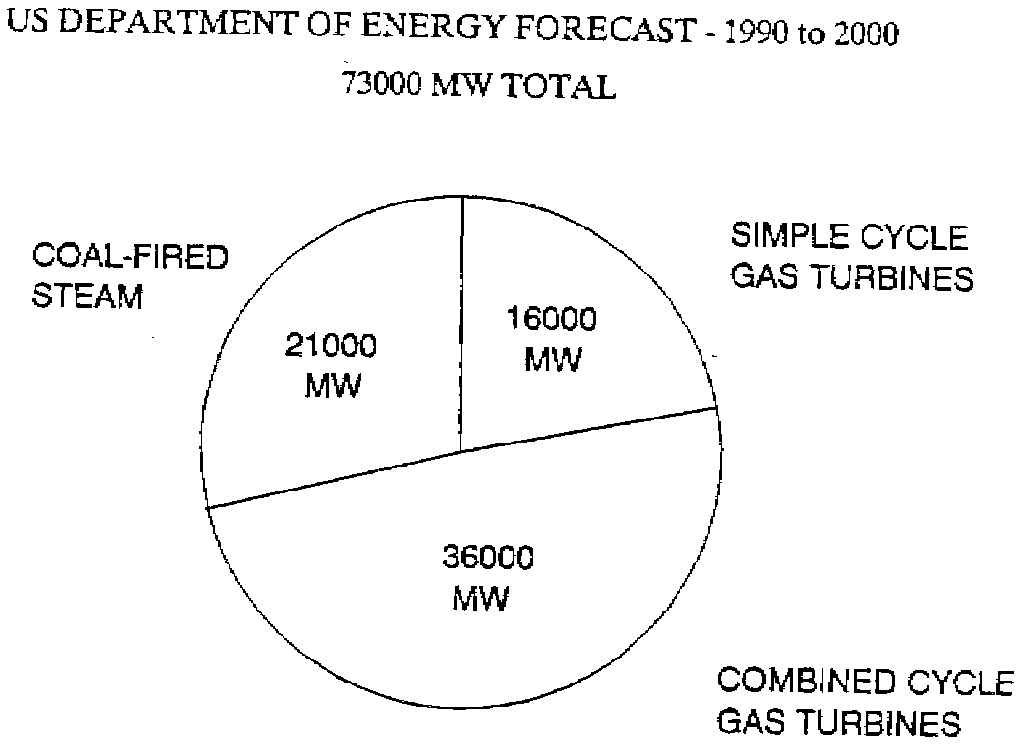


Figure 3-10. Total capacity to be purchased by the utility industry.[21]

shows, DOE expects 36,000 MW of combined cycle and 16,000 MW of simple cycle gas turbines to be purchased. This renewed interest in gas turbines is a result of:

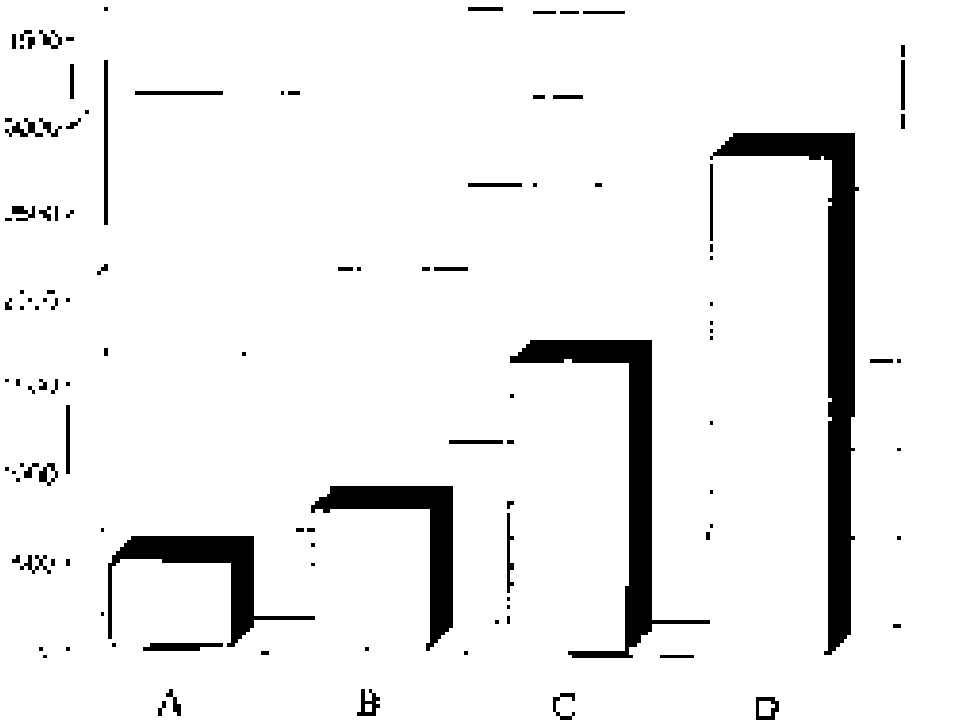
1. The introduction of new, larger, more efficient gas turbines;

2. Lower natural gas prices and proven reserves to meet current demand levels for more than 100 years;

3. Shorter lead times than those of competing equipment; and

4. Lower capital costs for gas turbines.[21]

Utility capital cost estimates, as shown in Figure 3-11



A - Repower existing plant using combined cycle gas turbines
B - New plant using combined cycle gas turbines
C - New plant using coal fired boilers
D - New plant using nuclear power

Figure 3-11. Capital costs for electric utility plants.[24]

, are (1) $500 per KW for repowering existing plants with combined cycle gas turbines, (2) $800 per KW for new combined cycle plants, (3) $1,650 per KW for new coal-fired plants, and (4) $2,850 per KW for new nuclear-powered plants.[24]

Gas turbines are also an alternative to displace planned or existing nuclear facilities. A total of 1,020 MW of gas turbine-generated electric power was recently commissioned in Michigan at a plant where initial design and construction had begun for a nuclear plant. Four additional idle nuclear sites are considering switching to gas turbine-based power production due to the legal, regulatory, financial, and public obstacles facing nuclear facilities.[24]

3.3.5 Other Industrial Applications

Industrial applications for gas turbines include various types of mechanical drive and air compression equipment. These applications peaked in the late 1960's and declined through the 1970's.[25] With the promulgation of PURPA in 1978 (see Section 3.3.3), many industrial facilities have found it

economically feasible to install a combined cycle gas turbine to meet power and steam requirements. Review of editions of Gas Turbine World over the last several years shows that a broad range of industries (e.g., pulp and paper, chemical, and food processing) have installed combined cycle gas turbines to meet their energy requirements.

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4.0 CHARACTERIZATION OF NO_x EMISSIONS

This section presents the principles of NO_x formation, the types of NO_x emitted (i.e., thermal NO_x, prompt NO_x, and fuel NO_x), and how they are generated in a gas turbine combustion process. Estimated NO_x emission factors for gas turbines and the bases for the estimates are also presented.

4.1 THE FORMATION OF NO_x

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of nitrogen (N_2) and oxygen (O_2) into N and O, respectively. Reactions following this dissociation result in seven known oxides of nitrogen: NO, NO_2, NO_3, N_2O, N_2O_3, N_2O_4, and N_2O_5. Of these, nitric oxide (NO) and nitrogen dioxide (NO_2) are formed in sufficient quantities to be significant in atmospheric pollution.[1] In this document, "NO_x" refers to either or both of these gaseous oxides of nitrogen.

Virtually all NO_x emissions originate as NO. This NO is further oxidized in the exhaust system or later in the atmosphere to form the more stable NO_2 molecule.[2] There are two mechanisms by which NO_x is formed in turbine combustors: (1) the oxidation of atmospheric nitrogen found in the combustion air (thermal NO_x and prompt NO_x) and (2) the conversion of nitrogen chemically bound in the fuel (fuel NO_x). These mechanisms are discussed below.

4.1.1 Formation of Thermal and Prompt NO_x

Thermal NO_x is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form oxides of nitrogen.

The major contributing chemical reactions are known as the Zeldovich mechanism and take place in the high temperature area of the gas turbine combustor.[3] Simply stated, the Zeldovich mechanism postulates that thermal NO_x formation increases exponentially with increases in temperature and linearly with increases in residence time.[4]

Flame temperature is dependent upon the equivalence ratio, which is the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.[5] An equivalence ratio of 1.0 corresponds to the stoichiometric ratio and is the point at which a flame burns at its highest theoretical temperature.[5] Figure 4-1

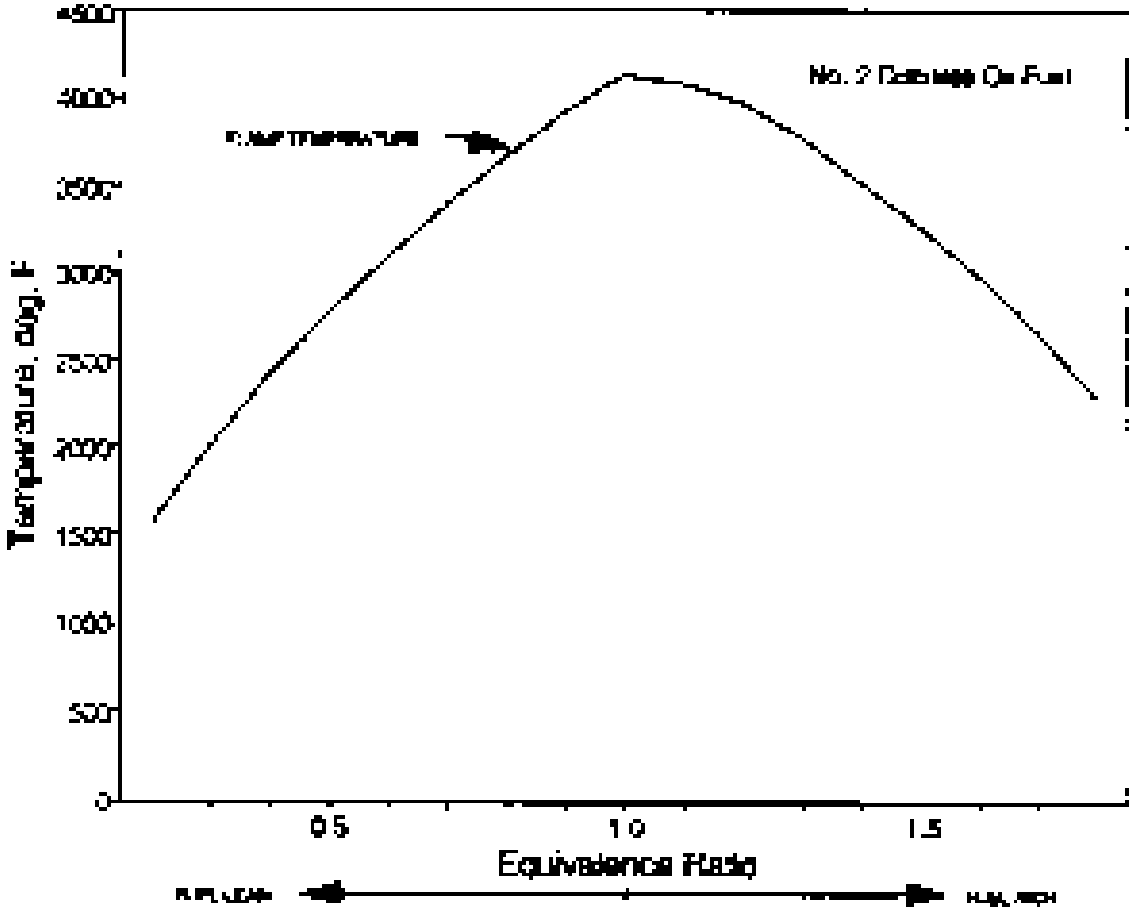


Figure 4-1. Influence of equivalence ratio on flame temperature.[4]

shows the flame temperature and equivalence ratio relationship for combustion using No. 2 distillate fuel oil (DF-2).[4]

The series of chemical reactions that form thermal NO_x according to the Zeldovich mechanism are presented below.[3]

1. $O_2 \rightleftharpoons 2O$;

2. $N_2 \rightleftharpoons 2N$;

3. $N + O \rightleftharpoons NO$;

4. $N + O_2 \rightleftharpoons NO + O$; and

5. $O + N_2 \rightleftharpoons NO + N$.

This series of equations applies to a fuel-lean combustion process. Combustion is said to be fuel-lean when there is excess oxygen available (equivalence ratio <1.0). Conversely, combustion is fuel-rich if insufficient oxygen is present to burn all of the available fuel (equivalence ratio >1.0). Additional equations have been developed that apply to fuel-rich combustion. These equations are an expansion of the above series to add an intermediate hydroxide molecule (OH):[3]

6. $N + OH \rightleftharpoons NO + H$,

and further to include an intermediate product, hydrogen cyanide (HCN), in the formation process:[3]

7. $N_2 + CH \rightleftharpoons HCN + N$ and

8. $N + OH \rightleftharpoons H + NO$.

The overall equivalence ratio for gases exiting the gas turbine combustor is less than 1.0.[4] Fuel-rich areas do exist in the overall fuel-lean environment, however, due to less-than-ideal fuel/air mixing prior to combustion. This being the case, the above equations for both fuel-lean and fuel-rich combustion apply for thermal NO_x formation in gas turbines.

Prompt NO_x is formed in the proximity of the flame front as intermediate combustion products such as HCN, N, and NH are oxidized to form NO_x as shown in the following equations:

1. $CH + N_2 \rightleftharpoons HCN + N$;

2. $CH_2 + N_2 \rightleftharpoons HCN + NH$; and

3. $HCN, N, NH + O_x \rightleftharpoons NO + ...$[6]

Prompt NO_x is formed in both fuel-rich flame zones and fuel-lean premixed combustion zones. The contribution of prompt NO_x to overall NO_x emissions is relatively small in conventional near-stoichiometric combustors, but this contribution increases with decreases in the equivalence ratio (fuel-lean mixtures). For this reason, prompt NO_x becomes an important consideration for the low-NO_x combustor designs described in Chapter 5 and establishes a minimum NO_x level attainable in lean mixtures.[7]

4.1.2 Formation of Fuel NO_x

Fuel NO_x (also known as organic NO_x) is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as

N_2 in some natural gas, does not contribute significantly to fuel NO_x formation.[8] However, nitrogen compounds are present in coal and petroleum fuels as pyridine-like (C_5H_5N) structures that tend to concentrate in the heavy resin and asphalt fractions upon distillation. Some low-British thermal unit (Btu) synthetic fuels contain nitrogen in the form of ammonia (NH_3), and other low-Btu fuels such as sewage and process waste-stream gases also contain nitrogen. When these fuels are burned, the nitrogen bonds break and some of the resulting free nitrogen oxidizes to form NO_x.[9] With excess air, the degree of fuel NO_x formation is primarily a function of the nitrogen content in the fuel. The fraction of fuel-bound nitrogen (FBN) converted to fuel NO_x decreases with increasing nitrogen content, although the absolute magnitude of fuel NO_x increases. For example, a fuel with 0.01 percent nitrogen may have 100 percent of its FBN converted to fuel NO_x, whereas a fuel with a 1.0 percent FBN may have only a 40 percent fuel NO_x conversion rate. The low-percentage FBN fuel has a 100 percent conversion rate, but its overall NO_x emission level would be lower than that of the high-percentage FBN fuel with a 40 percent conversion rate.[10]

Nitrogen content varies from 0.1 to 0.5 percent in most residual oils and from 0.5 to 2 percent for most U.S. coals.[11] Traditionally, most light distillate oils have had less than 0.015 percent nitrogen content by weight. However, today many distillate oils are produced from poorer-quality crudes, especially in the northeastern United States, and these distillate oils may contain percentages of nitrogen exceeding the 0.015 threshold; this higher nitrogen content can increase fuel NO_x formation.[4] At least one gas turbine installation burning coal-derived fuel is in commercial operation in the United States.[12]

Most gas turbines that operate in a continuous duty cycle are fueled by natural gas that typically contains little or no FBN. As a result, when compared to thermal NO_x, fuel NO_x is not

currently a major contributor to overall NO_x emissions from stationary gas turbines.

4.2 UNCONTROLLED NO_x EMISSIONS

The NO_x emissions from gas turbines are generated entirely in the combustor section and are released into the atmosphere via the stack. In the case of simple and regenerative cycle operation, the combustor is the only source of NO_x emissions. In cogeneration and combined cycle applications, a duct burner may be placed in the exhaust ducting between the gas turbine and the heat recovery steam generator (HRSG); this burner also generates NO_x emissions. (Gas turbine operating cycles are discussed in Section 3.2.) The amount of NO_x formed in the combustion zone is "frozen" at this level regardless of any temperature reductions that occur at the downstream end of the combustor and is released to the atmosphere at this level.[1]

4.2.1 Parameters Influencing Uncontrolled NO_x Emissions

The level of NO_x formation in a gas turbine, and hence the NO_x emissions, is unique (by design factors) to each gas turbine model and operating mode. The primary factors that determine the amount of NO_x generated are the combustor design, the types of fuel being burned, ambient conditions, operating cycles, and the power output level as a percentage of the rated full power output of the turbine. These factors are discussed below.

4.2.1.1 Combustor Design. The design of the combustor is the most important factor influencing the formation of NO_x. Design considerations are presented here and discussed further in Chapter 5.

Thermal NO_x formation, as discussed in Section 4.1.1, is influenced primarily by flame temperature and residence time. Design parameters controlling equivalence ratios and the introduction of cooling air into the combustor strongly influence thermal NO_x formation. The extent of fuel/air mixing prior to combustion also affects NO_x formation. Simultaneous mixing and combustion results in localized fuel-rich zones that yield high flame temperatures in which substantial thermal NO_x production

takes place.[13] The dependence of thermal NO_x formation on flame temperature and equivalence ratio is shown in Figure 4-2

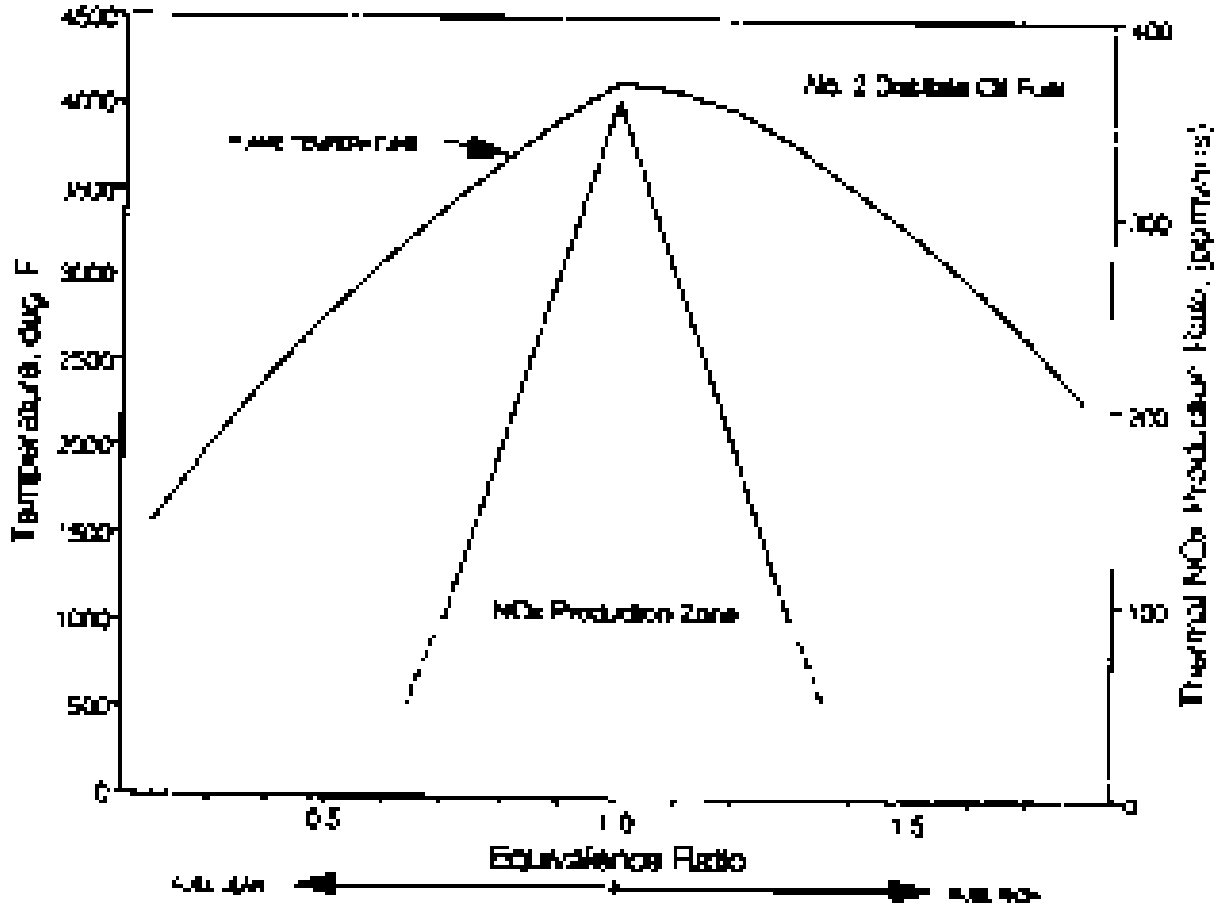


Figure 4-2. Thermal NO_x production as a function of flame temperature and equivalence ratio.[4]

for DF-2.[4] Conversely, prompt NO_x is largely insensitive to changes in temperature and pressure.[7]

Fuel NO_x formation, as discussed in Section 4.1.2, is formed when FBN is released during combustion and oxidizes to form NO_x. Design parameters that control equivalence ratio and residence time influence fuel NO_x formation.[14]

4.2.1.2 Type of Fuel. The level of NO_x emissions varies for different fuels. In the case of thermal NO_x, this level increases with flame temperature. For gaseous fuels, the constituents in the gas can significantly affect NO_x emissions levels. Gaseous fuel mixtures containing hydrocarbons with molecular weights higher than that of methane (e.g., ethane, propane, and butane) burn at higher flame temperatures and as a result can increase NO_x emissions greater than 50 percent over NO_x levels for methane gas fuel. Refinery gases and some unprocessed field gases contain significant levels of these higher molecular weight hydrocarbons. Conversely, gas fuels that contain significant inert gases, such as CO_2, generally produce lower NO_x emissions. These inert gases serve to absorb heat during combustion, thereby lowering flame temperatures and reducing NO_x emissions. Examples of this type of gas fuel are air-blown gasifier fuels and some field gases.[15] Combustion of hydrogen also results in high flame temperatures, and gases with significant hydrogen content produce relatively high NO_x emissions. Refinery gases can have hydrogen contents exceeding 50 percent.[16]

As is shown in Figure 4-3

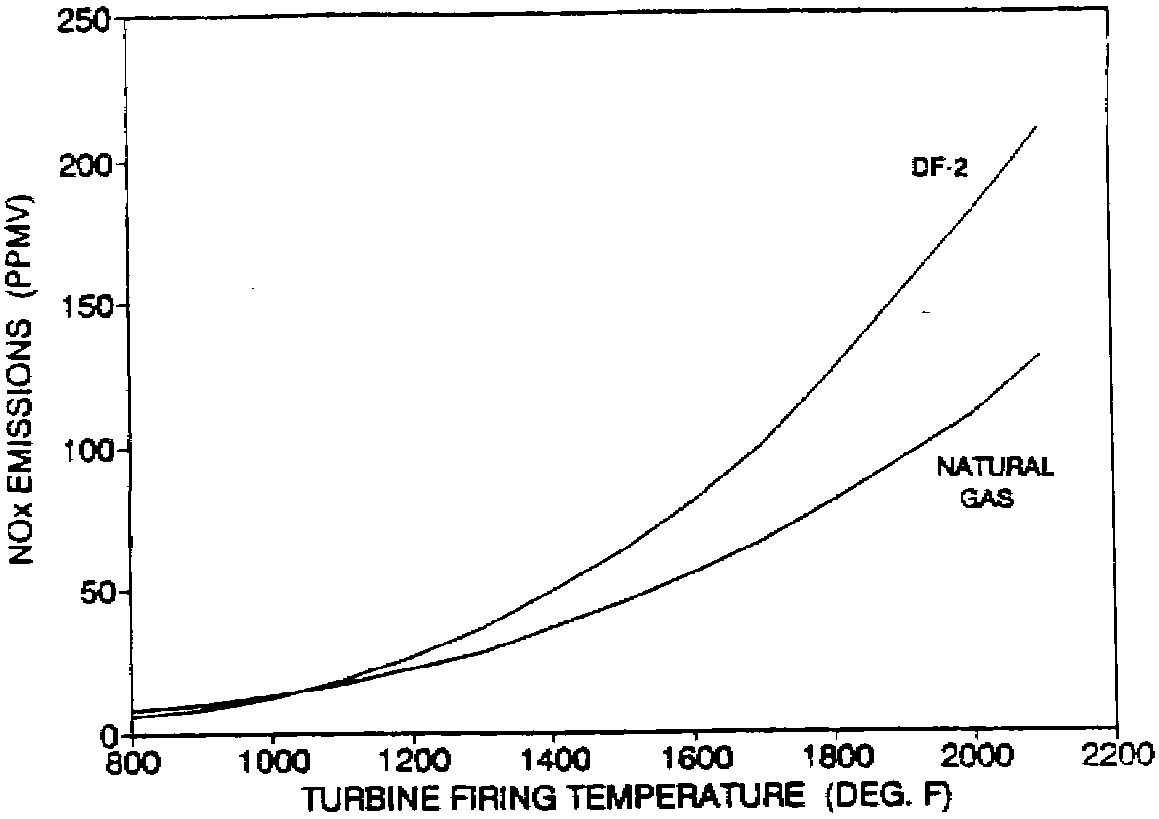


Figure 4-3. Influence of firing temperature on thermal NO_x formation.[17]

, DF-2 burns at a flame temperature that is approximately 75°C (100°F) higher than that of natural gas, and as a result, NO_x emissions are higher when burning DF-2 than they are when burning natural gas.[17] Low-Btu fuels such as coal gas burn with lower flame temperatures, which result in

substantially lower thermal NO_x emissions than natural gas or DF-2.[18] For fuels containing FBN, the fuel NO_x production increases with increasing levels of FBN.

4.2.1.3 Ambient Conditions. Ambient conditions that affect NO_x formation are humidity, temperature, and pressure. Of these ambient conditions, humidity has the greatest effect on NO_x formation.[19] The energy required to heat the airborne water vapor has a quenching effect on combustion temperatures, which reduces thermal NO_x formation. At low humidity levels, NO_x emissions increase with increases in ambient temperature. At high humidity levels, the effect of changes in ambient temperature on NO_x formation varies. At high humidity levels and low ambient temperatures, NO_x emissions increase with increasing temperature. Conversely, at high humidity levels and ambient temperatures above 10°C (50°F), NO_x emissions decrease with increasing temperature.

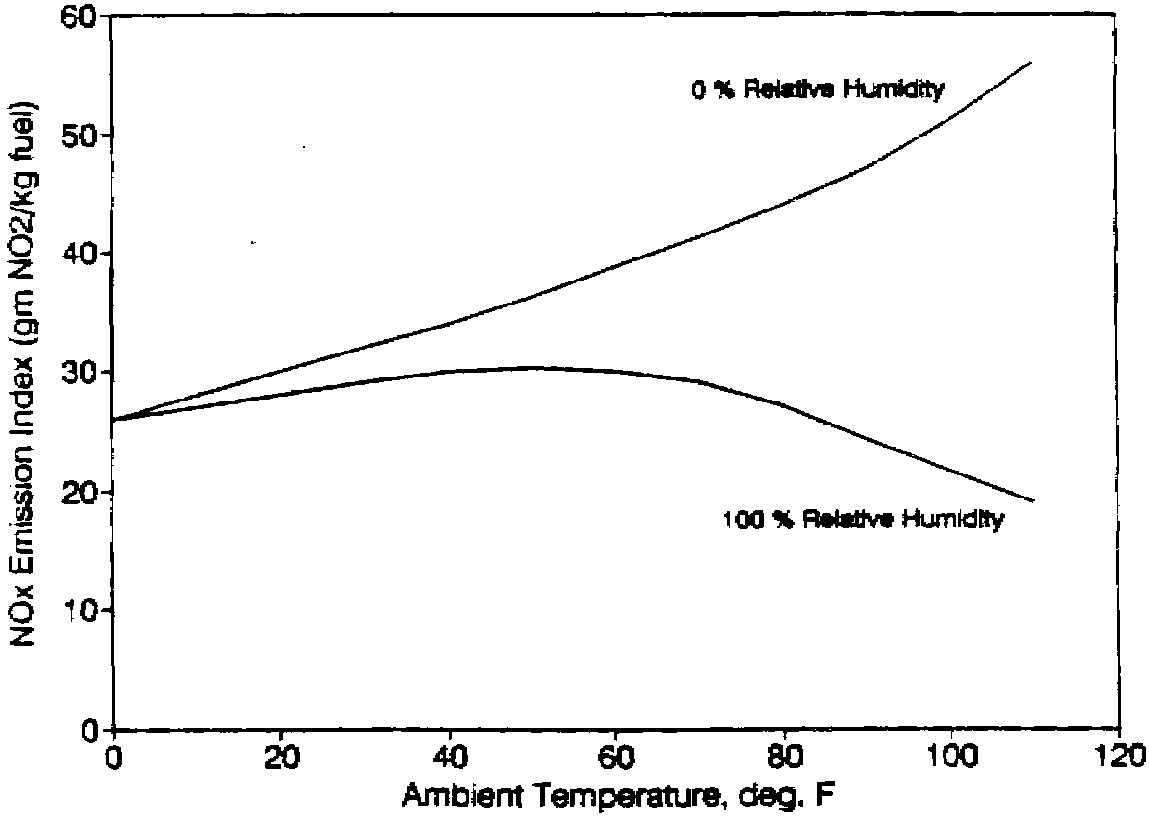


Figure 4-4. Influence of relative humidity and ambient temperature on NO_x formation.[19]

This effect of humidity and temperature on NO_x formation is shown in Figure 4-4. A rise in ambient pressure results in higher pressure and temperature levels entering the combustor and so No_x production levels increase with increases in ambient pressure.[19]

The influence of ambient conditions on measured NO_x emission levels can be corrected using the following equation:[20]

$$NO_x = (NO_{xo})(P_r/P_o)^{0.5} e^{19(Ho-0.00633)} (288°K/T_a)^{1.53}$$

where:

NO_x = emission rate of NO_x at 15 percent O_2 and International Standards Organization (ISO) ambient conditions, volume percent;

NO_{xo} = observed NO_x concentration, parts per million by volume (ppmv) referenced to 15 percent O_2;

P_r = reference compressor inlet absolute pressure at 101.3 kilopascals ambient pressure, millimeters mercury (mm Hg);

P_o = observed compressor inlet absolute pressure at test, mm Hg;

H_o = observed humidity of ambient air, g H_2O/g air;

e = transcendental constant, 2.718; and

T_a = ambient temperature, K.

At least two manufacturers state that this equation does not accurately correct NO_x emissions for their turbine models.[8,12] It is expected that these turbine manufacturers could provide corrections to this equation that would more accurately correct NO_x emissions for the effects of ambient conditions based on test data for their turbine models.

4.2.1.4 Operating Cycles. Emissions from identical turbines used in simple and cogeneration cycles have similar NO_x emissions levels, provided no duct burner is used in heat recovery applications. The NO_x emissions are similar because, as stated in Section 4.2, NO_x is formed only in the turbine combustor and remains at this level regardless of downstream temperature reductions. A turbine operated in a regenerative cycle produces higher NO_x levels, however, due to increased combustor inlet temperatures present in regenerative cycle applications.[21]

4.2.1.5 Power Output Level. The power output level of a gas turbine is directly related to the firing temperature, which is directly related to flame temperature. Each gas turbine has a base-rated power level and corresponding NO_x level. At power outputs below this base-rated level, the flame temperature is lower, so NO_x emissions are lower. Conversely, at peak power outputs above the base rating, NO_x emissions are higher due to higher flame temperature. The NO_x emissions for a range of firing temperatures are shown in Figure 4-3 for one manufacturer's gas turbine.[17]

4.2.2 NO_x Emissions From Duct Burners

In some cogeneration and combined cycle applications, the exhaust heat from the gas turbine is not sufficient to produce the desired quantity of steam from the HRSG, and a supplemental burner, or duct burner, is placed in the exhaust duct between the gas turbine and HRSG to increase temperatures to sufficient

levels. In addition to providing additional steam capacity, this burner also increases the overall system efficiency since essentially all energy added by the duct burner can be recovered in the HRSG.[22]

The level of NO_x produced by a duct burner is approximately 0.1 pound per million Btu (lb/MMBtu) of fuel burned. The ppmv level depends upon the flowrate of gas turbine exhaust gases in which the duct burner is operating and thus varies with the size of the turbine.[23]

Typical NO_x production levels added by a duct burner operating on natural gas fuel are:[23]

Gas turbine output, megawatts (MW)	Duct burner NO_x, ppmv, referenced to 15 percent O_2
3 to 50	10 to 30
50+	5 to 10

4.3 UNCONTROLLED EMISSION FACTORS

TABLE 4-1. UNCONTROLLED NO_x EMISSIONS FACTORS FOR GAS TURBINES AND DUCT BURNERS[8,12,15,24-29]

Manufacturer	Model No.	Output, MW	NO_x emissions, ppmv, dry and corrected to 15% O_2		NO_x emissions factor, lb NO_x/MMBtu[a]	
			Natural gas	Distillate oil No. 2	Natural gas	Distillate oil No. 2
Solar	Saturn	1.1	99	150	0.397	0.551
	Centaur	3.3	130	179	0.521	0.658
	Centaur "H"	4.0	105	160	0.421	0.588
	Taurus	4.5	114	168	0.457	0.618
	Mars T12000	8.8	178	267	0.714	0.981
	Mars T14000	10.0	199	NA[b]	0.798	NA[b]
GM/Allison	501-KB5	4.0	155	231	0.622	0.849
	570-KA	4.9	101	182	0.405	0.669
	571-KA	5.9	101	182	0.405	0.669
General Electric	LM1600	12.8	144	237	0.577	0.871
	LM2500	21.8	174	345	0.698	1.27
	LM5000	33.1	185	364	0.742	1.34
	LM6000	41.5	220	417	0.882	1.53
	MS5001P	26.3	142	211	0.569	0.776
	MS6001B	38.3	148	267	0.593	0.981
	MS7001EA	83.5	154	228	0.618	0.838
	MS7001F	123	179	277	0.718	1.02
	MS9001EA	150	176	235	0.706	0.864
	MS9001F	212	176	272	0.706	1.00
Asea Brown Boveri	GT8	47.4	430	680	1.72	2.50
	GT10	22.6	150	200	0.601	0.735
	GT11N	81.6	390	560	1.56	2.06
	GT35	16.9	300	360	1.20	1.32
Westinghouse	W261B11/12	52.3	220	355	0.882	1.31
	W501D5	119	190	250	0.762	0.919
Siemens	V84.2	105	212	360	0.850	1.32
	V94.2	153	212	360	0.850	1.32
	V64.3	61.5	380	530	1.52	1.95
	V84.3	141	380	530	1.52	1.95
	V94.3	203	380	530	1.52	1.95
Duct burners	All	NA[c]	≤30	NA[b]	<0.100[d]	NA[b]

[a]Based on emission levels provided by gas turbine manufacturers, corresponding to rated load at ISO conditions. NO_x emissions calculations are shown in Appendix A.

[b]Not available.

[c]Not applicable.

[d]References 16 and 22.

Uncontrolled emission factors are presented in Table 4-1. These factors are based on uncontrolled emission levels provided by manufacturers in ppmv, dry, and corrected to 15 percent O_2, corresponding to 100 percent output load and International Standards Organization (ISO) conditions of 15°C (59°F) and 1 atmosphere (14.7 psia). Sample calculations are given in Appendix A. The uncontrolled emissions factors range from 0.397 to 1.72 lb/MMBtu (99 to 430 ppmv) for natural gas and 0.551 to 2.50 lb/MMBtu (150 to 680 ppmv) for DF-2.

4.4 REFERENCES FOR CHAPTER 4

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5.0 NO_x CONTROL TECHNIQUES

Nationwide NO_x emission limits have been established for stationary gas turbines in the new source performance standards (NSPS) promulgated in 1979.[1] This standard, summarized in Table 5-1

TABLE 5-1. NO_x EMISSION LIMITS AS ESTABLISHED BY THE NEW SOURCE PERFORMANCE STANDARDS FOR GAS TURBINES[1]

Fuel input MMBtu/hr	Size, MW	Application(s)	NO_x limit, ppmv at 15% O_2, dry[a] [b]
<10	1[c]	All	None
10-100	1-10[c]	All	150
>100	10+[c] <30[c] >30[c]	Utility[d] Nonutility Nonutility	75 150 None
<100	10[c]	Regenerative cycle	None
All	All	e	None

[a]Based on thermal efficiency of 25 percent. This limit may be increased for higher efficiencies by multiplying the limit in the table by 14.4/actual heat rate, in kJ/watt-hr.

[b]A fuel-bound nitrogen allowance may be added to the limits listed in the table according to the table listed below:

Fuel-bound nitrogen (N), percent by weight	Allowable increase, ppmv
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	400 x N
$0.1 < N \leq 0.25$	40 + [6.7 x (N - 0.1)]
$N > 0.25$	50

[c]Based on gas turbine heat rate of 10,000 Btu/kW-hr.

[d]An installation is considered a utility if more than 1/3 of its potential electrical output is sold.

[e]Emergency/stand-by, military (except garrison facilities), military training, research and development, firefighting, and emergency fuel operation applications are exempt from NO_x emission limits.

, effectively sets a limit for new, modified, or reconstructed gas turbines greater than 10.7 gigajoules per hour (approximately 3,800 horsepower [hp]) of 75 or 150 parts per million by volume (ppmv), corrected to 15 percent oxygen (O_2) on a dry basis, depending upon the size and application of the turbine. State and regional regulatory agencies may set more restrictive limits, and two organizations have established limits as low as 9 ppmv: the South Coast Air Quality Management District (SCAQMD) has defined limits as listed in Table 5-2

TABLE 5-2. NO_x COMPLIANCE LIMITS AS ESTABLISHED BY THE SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT (SCAQMD) FOR EXISTING TURBINES. RULE 1134. ADOPTED AUGUST 1989.[a,2]

Unit size, megawatt rating (MW)	NO_x limit, ppmv, 15% O_2 dry[b]
0.3 to <2.9 MW	25
2.9 to <10.0 MW	9
2.9 to <10.0 MW No SCR	15
10.0 MW and over	9
10.0 MW and over No SCR	12
60 MW and over Combined cycle No SCR	15
60 MW and over Combined cycle	9
Compliance limit = Reference limit X EFF/25 percent	
where: $EFF = \frac{3,413 \times 100\%}{\text{Actual heat rate at HHV of fuel (Btu/kW-hr)}}$ or EFF^c = (Manufacturer's rated efficiency at LHV) x $\frac{LHV}{HHV}$	

[a]The NO_x reference limits to be effective by December 31, 1995.
[b]Averaged over 15 consecutive minutes.
[c]EFF = the demonstrated percent efficiency of the gas turbine only as calculated without consideration of any down-stream energy recovery from the actual heat rate (Btu/kW-hr), or 1.34 (Btu/hp-hr); corrected to the higher heating value (HHV) of the fuel and ISO conditions, as measured at peak load for that facility; or the manufacturer's continuous rated percent efficiency (manufacturer's rated efficiency) of the gas turbine after correction from lower heating value (LHV) to the HHV of the fuel, whichever efficiency is higher. The value of EFF shall not be less than 25 percent. Gas turbines with lower efficiencies will be assigned a 25 percent efficiency for this calculation.

; and the Northeast States for Coordinated Air Use Management (NESCAUM) has recommended limits as listed in Table 5-3.

TABLE 5-3. NO_x EMISSION LIMITS RECOMMENDED BY THE NORTHEAST STATES FOR COORDINATED AIR USE MANAGEMENT (NESCAUM)

NEW TURBINES[3]

Fuel input, MMBtu/hr	Size, MW[a]	Fuel type	NO_x limit, ppmv[b]
1-100	1-10	Gas Oil	42 65
>100	10+	Gas Oil Gas/oil back-up	9[c] 9[c] 9[c]/18[c d]

[a]Based on gas turbine heat rate of 10,000 Btu/kW-hr.
[b]Dry basis, corrected to 15 percent oxygen.
[c]Based on use of selective catalytic reduction (SCR). Limits for operation without SCR, where permitted, should be the turbine manufacturer's lowest guaranteed NO_x limit.
[d]Based on the use of SCR and a fuel-bound nitrogen content of 600 ppm or less.

EXISTING TURBINES[4]

Operating cycle	Fuel	NO_x emission limit, ppmv, 15 percent O_2
Simple	Gas, no oil back-up	55
	Oil	75
	Gas, with oil back-up	55 (Gas fuel) 75 (Oil fuel)
Combined	Gas, no oil back-up	42
	Oil	65
	Gas, with oil back-up	42 (Gas fuel) 65 (Oil fuel)

Note: Applies to existing turbines rated at 25 MMBtu/hr or above (maximum heat input rate).

This chapter discusses the control techniques that are available to reduce NO_x emissions for stationary turbines, the use of duct burners, the use of alternate fuels to lower NO_x emissions, and the applicability of NO_x control techniques to offshore applications. Each control technique is structured into categories to discuss the process description, applicability, factors that affect performance, and achievable controlled NO_x emission levels. Where information for a technique is limited, one or more categories may be combined. Section 5.1 describes wet controls, including water and steam injection. Section 5.2 describes combustion controls, including lean and staged combustion. Selective catalytic reduction (SCR), a postcombustion technique, is described in Section 5.3, and the combination of SCR with other control techniques is described in

Section 5.4. Emissions from duct burners and their impact on total NO_x emissions are described in Section 5.5. Section 5.6 describes NO_x emission impacts when using alternate fuels. Two control techniques that show potential for future use, selective noncatalytic reduction (SNCR) and catalytic combustion, are described in Sections 5.7 and 5.8, respectively. Control technologies for offshore oil platforms are described in Section 5.9. Finally, references for Chapter 5 are found in Section 5.10.

5.1 WET CONTROLS

The injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_x formation. This control technique is available from all gas turbine manufacturers contacted for this study.[5-11]

The process description, applicability, factors affecting performance, emissions data and manufacturers' guarantees, impacts on other emissions, and gas turbine performance and maintenance impacts are discussed in this section.

5.1.1 Process Description

Injecting water into the flame area of a turbine combustor provides a heat sink that lowers the flame temperature and thereby reduces thermal NO_x formation. Injection rates for both water and steam are usually described by a water-to-fuel ratio (WFR) and are usually given on a weight basis (e.g., lb water to lb fuel).

A water injection system consists of a water treatment system, pump(s), water metering valves and instrumentation, turbine-mounted injection nozzles, and the necessary interconnecting piping. Water purity is essential to prevent or mitigate erosion and/or the formation of deposits in the hot section of the turbine; Table 5-4

TABLE 5-4. WATER QUALITY SPECIFICATIONS OF SELECTED GAS TURBINE MANUFACTURERS FOR WATER INJECTION SYSTEMS[11-18]

	Turbine Manufacturer							
Element	A	B	C	D	E	F	G	H
Total solids, ppm (dissolved and nondissolved)	5	5	1	a	0.1 gram/gallon	15	5	8
Total alkali metals, ppm	0.1	0.5 (HD) 0.1 (AD)[d]	0.1	--	0.5	0.15	<0.05	--
Calcium, ppm	5	--	--	--	--	--	<1.0	--
Sulfates, ppm	--	--	--	--	--	--	--	0.5
Silica, ppm	0.02	--	0.02	--	--	0.1	<0.02	0.1
Silicon, ppm	--	--	--	18.0	--	--	--	--
Sulfur, ppm	0.1	--	--	--	--	1.0	--	--
Chlorides, ppm	--	--	--	6.0	--	1.0	--	0.5
Iron and copper, ppm	--	--	--	0.1	--	--	--	--
Sodium and potassium, ppm	--	--	--	--	--	--	--	0.1
Particle size, microns	10	--	10	--	5	--	--	20
Total hardness, ppm	--	--	--	--	--	0.2	--	--
Oxygen[f]	--	--	--	--	--	--	--	--
Acidity, pH	7.0-8.5	6.5-7.5	7.0-8.5	7.5-8.0	--	6.5-7.5	6.5-7.0	6.0-8.0

[a]Determined by local regulations for particulates exhausted from combustion process.
[b]HD - heavy-duty turbine.
[c]Including vanadium and lead.
[d]AD - aeroderivative turbine.
[e]90 percent of 0.1 gram particles shall be less than 5 microns.

summarizes the water quality specifications for eight gas turbine manufacturers.

In a steam injection system, steam replaces water as the injected fluid. The injection system is similar to that for water injection, but the pump is replaced by a steam-producing boiler. This boiler is usually a heat recovery steam generator

(HRSG) that recovers the gas turbine exhaust heat and generates steam. The balance of the steam system is similar to the water injection system. The water treatment required for boiler feed water to the HRSG yields a steam quality that is suitable for injection into the turbine. The additional steam requirement for NO_x control, however, may require that additional capacity be added to the boiler feed water treatment system.

Another technique that is commercially available for oil-fired aeroderivative and industrial turbines uses a water-in-oil emulsion to reduce NO_x emissions. This technique introduces water into the combustion process by emulsifying water in the fuel oil prior to injection. This emulsion has a water content of 20 to 50 percent by volume and is finely dispersed and chemically stabilized in the oil phase. The principle of NO_x control is similar to conventional water injection, but the uniform dispersion of the water in the oil provides greater NO_x reduction than conventional water injection at similar WFR's.[19]

A water-in-oil emulsion injection system consists of mechanical emulsification equipment, chemical stabilizer injection equipment, water metering valves, chemical storage and metering valves, and instrumentation. In most cases the emulsifying system can be retrofitted to the existing fuel delivery system, which eliminates the requirement for a separate delivery system for water injection. At multiunit installations, one emulsion system can be used to supply emulsified fuel to several turbines. For dual fuel turbines, the emulsion can be injected through the oil fuel system to control NO_x emissions.[19]

Data provided by the vendor for this technique indicates that testing has been performed on oil-fired turbines operating in peaking duty. Long-term testing has not been completed at this point to quantify the long-term effects of the emulsifier on the operation and maintenance of the turbine.

5.1.2 Applicability of Wet Controls

Wet controls have been applied effectively to both aeroderivative and heavy-duty gas turbines and to all configurations except regenerative cycle applications.[20] It is expected that wet controls can be used with regenerative cycle turbines, but no such installations were identified. All manufacturers contacted have water injection control systems available for their gas turbine models; many also offer steam injection control systems. Where both systems are available, the decision of which control to use depends upon steam availability and economic factors specific to each site.

Wet controls can be added as a retrofit to most gas turbine installations. In the case of water injection, one limitation is the possible unavailability of injection nozzles for turbines operating in dual fuel applications. In this application, the injection nozzle as designed by the manufacturer may not physically accommodate a third injection port for water injection. This limitation also applies to steam injection. In addition, steam injection is not an available control option from some gas turbine manufacturers.

5.1.3 Factors Affecting the Performance of Wet Controls

The WFR is the most important factor affecting the performance of wet controls. Other factors affecting performance are the combustor geometry and injection nozzle(s) design and the fuel-bound nitrogen (FBN) content. These factors are discussed below.

The WFR has a significant impact on NO_x emissions. Tables 5-5 and 5-6 provide NO_x reduction and WFRs for natural gas and

TABLE 5-5. MANUFACTURER'S GUARANTEED NO_x REDUCTION EFFICIENCIES AND ESTIMATED WATER-TO-FUEL RATIOS FOR NATURAL GAS FUEL OPERATION[5-11,21-24]

	NO_x emission levels, ppmv at 15% O_2/NO_x percent reduction			Water-to-fuel ratio (lb water to lb fuel)	
Manufacturer/model	Uncontrolled	Water injection	Steam injection	Water injection	Steam injection
General Electric					
LM1600	133	42[a]/68	25/81	0.61	1.49
LM2500	174	42[a]/76	25/86	0.73	1.46
LM5000	185	42[a]/77	25/87	0.63	1.67
LM6000	220	42[a]/81	25/89	0.68	1.67
MS5001P	142	42/70	42/70	0.72	1.08
MS6001B	148	42/72	42/72	0.77	1.16
MS7001E	154	42/73	42/73	0.81	1.22
MS7001F	210	42/80	42/80	0.79	1.34
MS9001E	161	42/74	42/74	0.78	1.18
MS9001F	210	42/86	42/80	NA[b]	NA[b]
Asea Brown Boveri					
GT10	150	25/83	42/72	0.93	1.07
GT8	430	25/94	29/93	1.86	2.48
GT11N	390	25/94	25/94	1.76	2.47
GT35	300	42/86	60/80	1.00	1.20
Solar Turbines, Inc.					
T-1500 Saturn	99	42/58	NA[c]/NA[c]	0.33	NA[c]
T-4500 Centaur	130	42/68	NA[c]/NA[c]	0.61	NA[c]
Type H Centaur	105	42/60	NA[c]/NA[c]	0.70	NA[c]
Taurus	114	42/63	NA[c]/NA[c]	0.79	NA[c]
T-12000 Mars	178	42/76	NA[c]/NA[c]	0.91	NA[c]
T-14000 Mars	199	42/79	NA[c]/NA[c]	1.14	NA[c]
Allison/GM					
501-KB5	155	42/73	42/73	0.80	1.53
501-KC5	174	42/76	NA[c]/NA[c]	NA[b]	NA[c]
501-KH	155	42/73	25/84	NA[b]	NA[b]
570-K	101	42/58	NA[c]/NA[c]	NA[b]	NA[c]
571-K	101	42/58	NA[c]/NA[c]	0.80	NA[c]
Westinghouse					
251B11/12	220	42/81	25/89	1.0	1.8
501D5	190	25/87	25/87	1.6	1.6
Siemens					
V84.2	212	42/80	55/74	2.0	2.0
V94.2	212	55/74	55/74	1.6	1.6
V64.3	380	75/80	75/80	1.6	1.4
V84.3	380	75/80	75/80	1.6	1.4
V94.3	380	75/80	75/80	1.6	1.4

[a]A NO_x emissions level of 25 ppmv can be achieved, but turbine maintenance requirements increase over those required for 42 ppmv.

TABLE 5-6. MANUFACTURER'S GUARANTEED NO_x REDUCTION EFFICIENCIES AND ESTIMATED WATER-TO-FUEL RATIOS FOR DISTILLATE OIL FUEL OPERATION[5-11,21-24]

	NO_x emissions level, ppmv at 15% O_2/NO_x percent reduction			Water-to-fuel ratio (lb water to lb fuel)	
Manufacturer/model	Uncontrolled	Water injection	Steam injection	Water injection	Steam injection
General Electric					
LM1600	237	42/82	75/70	NA[a]	NA[a]
LM2500	345	42/88	75/78	0.99	NA[a]
LM5000	364	42/88	110/70	NA[a]	NA[a]
LM6000	417	42/90	110/74	NA[a]	NA[a]
MS5001P	211	65/69	65/69	0.79	1.06
MS6001B	267	65/76	65/76	0.73	1.20
MS7001E	228	65/72	65/72	0.67	1.19
MS7001F	353	65/82	65/77	0.72	1.35
MS9001E	241	65/73	65/72	0.65	1.16
MS9001F	353	65/82	65/76	NA[a]	NA[a]
Asea Brown Boveri					
GT10	200	42/79	42/79	0.75	1.25
GT8	680	42/94	60/91	1.62	2.15
GT11N	560	42/88	42/93	1.50	2.28
GT35	360	42/88	60/83	1.00	1.20
Solar Turbines, Inc.					
T-1500 Saturn	150	60/60	NA[b]/NA[b]	0.46	NA[b]
T-4500 Centaur	179	60/66	NA[b]/NA[b]	0.60	NA[b]
Type H Centaur	160	60/63	NA[b]/NA[b]	0.72	NA[b]
Taurus	168	60/64	NA[b]/NA[b]	0.96	NA[b]
T-12000 Mars	267	60/78	NA[b]/NA[b]	1.00	NA[b]
T-14000 Mars	NA[a]	60/NA[a]	NA[b]/NA[b]	NA[a]	NA[b]
Allison/GM					
501-KB5	231	56/76	NA[b]/NA[b]	NA[a]	NA[b]
501-KC5	NA[a]	NA[a]/NA[a]	NA[b]/NA[b]	NA[a]	NA[b]
501-KH	231	56/76[a]	50/78	NA[a]	NA[a]
570-K	182	65/64[a]	NA[b]/NA[b]	NA[a]	NA[b]
571-K	182	65/64[a]	NA[b]/NA[b]	NA[a]	NA[b]
Westinghouse					
251B11/12	355	65/82	42/88	1.0	1.8
501D5	250	42/83	42/83	1.0	1.6
Siemens					
V84.2	360	42/88	55/85	1.4	2.0
V94.2	360	42/88	55/85	1.4	1.6
V64.3	530	75/86	75/86	1.2	1.4
V84.3	530	75/86	75/86	1.2	1.4
V94.3	530	75/86	75/86	1.2	1.4

[a]Data not available.

distillate oil fuels, respectively, based on information provided by gas turbine manufacturers. For natural gas fuel, WFR's for water or steam injection range from 0.33 to 2.48 to achieve controlled NO_x emission levels ranging from 25 to 75 ppmv, corrected to 15 percent oxygen. For oil fuel, WFR's range from 0.46 to 2.28 to achieve controlled NO_x emission levels ranging from 42 to 110 ppmv, corrected to 15 percent oxygen. Nitrogen oxide reduction efficiency increases as the WFR

increases. As shown in Tables 5-5 and 5-6, reduction efficiencies of 70 to 90 percent are common. Note that, in general, the WFR's for steam are higher than for water injection because water acts as a better heat sink than steam due to the heat absorbed by vaporization; therefore, higher levels of steam than water must be injected for a given reduction level.

The combustor geometry and injection nozzle design and location also affect the performance of wet controls. For maximum NO_x reduction efficiency, the water must be atomized and injected in a spray pattern that provides a homogeneous mixture of water droplets and fuel in the combustor. Failure to achieve this mixing yields localized hot spots in the combustor that produce increased NO_x emissions.

The type of fuel affects the performance of wet controls. In general, lower controlled NO_x emission levels can be achieved with gaseous fuels than with oil fuels. The FBN content also affects the performance of wet controls. Those fuels with relatively high nitrogen content, such as coal-derived liquids, shale oil, and residual oils, result in significant fuel NO_x formation. Natural gas and most distillate oils are low-nitrogen fuels. Consequently, fuel NO_x formation is minimal when these fuels are burned.

Wet controls serve only to lower the flame temperature and therefore are an effective control only for thermal NO_x formation; water injection may in fact increase the rate of fuel NO_x formation, as shown in Figure 5-1.[25] The mechanisms responsible for this potential increase were not identified.

5.1.4 Achievable NO_x Emissions Levels Using Wet Controls

This section presents the achievable controlled NO_x emission levels for wet injection, as guaranteed by gas turbine manufacturers. Emission test data, obtained using EPA Test Method 20 or equivalent, are also presented.

Guaranteed NO_x emission levels as provided by gas turbine manufacturers for wet controls are shown in Figures 5-2 and

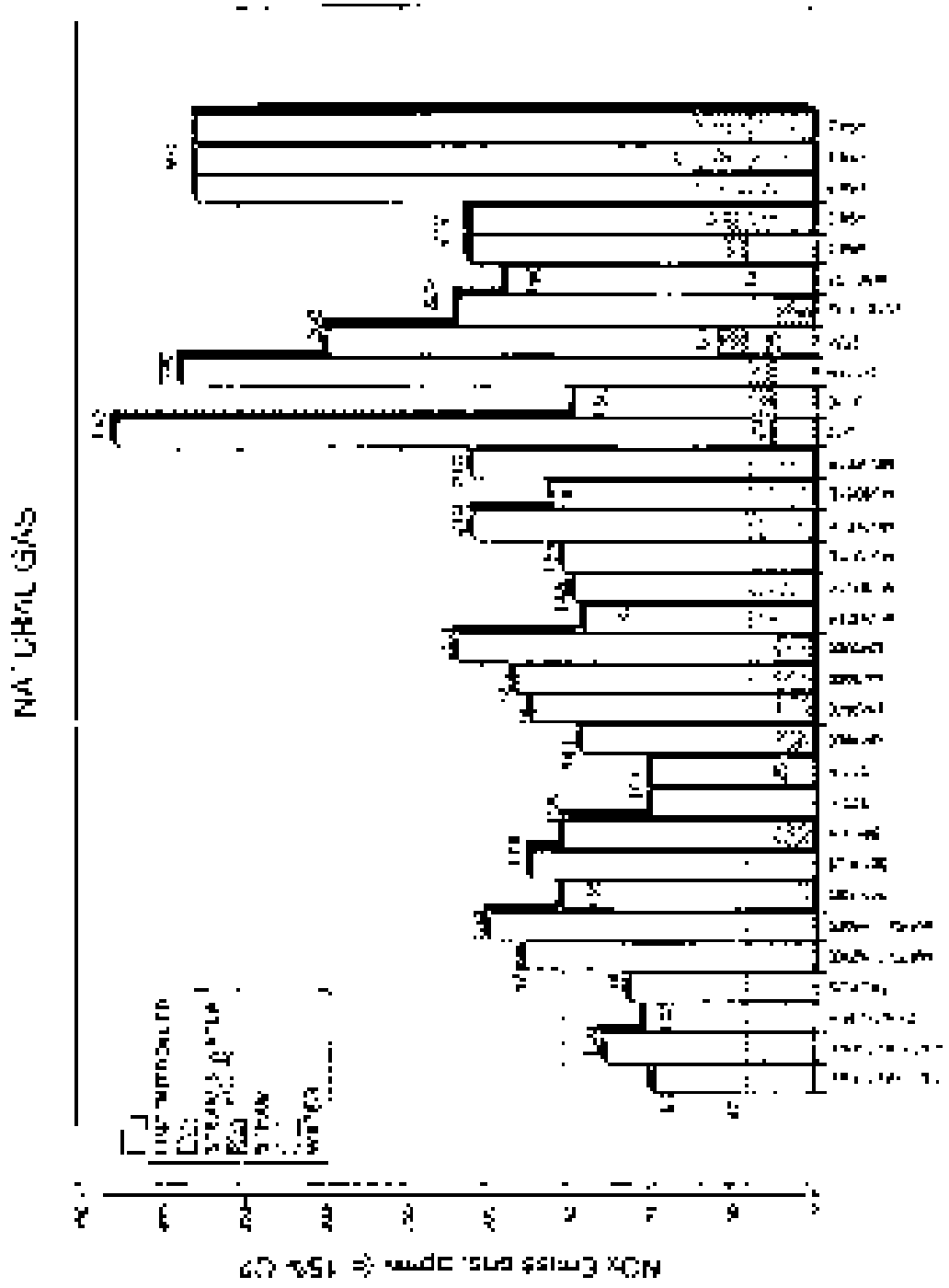


Figure 5-1. Percentage of fuel-bound nitrogen converted to NO_x versus the fuel-bound nitrogen content and the water-to-fuel ratio for controlled NO_x emissions and dry control.

Figure 5-2. Typical uncontrolled NO_x emissions and guaranteed controlled levels using wet injection. Natural gas fuel.

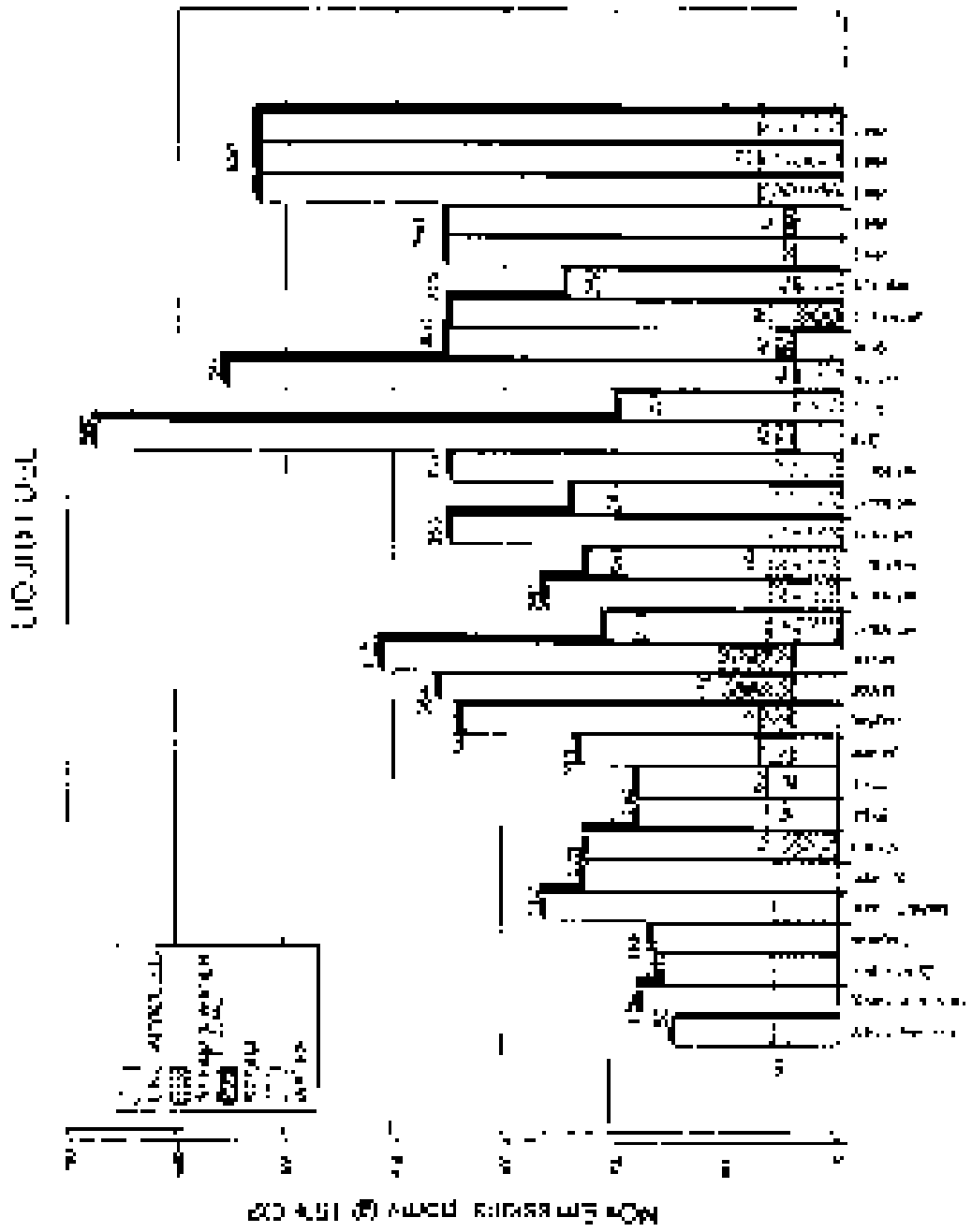


Figure 5-3. Uncontrolled NO_x emissions and gas turbine manufacturers' guaranteed controlled levels using wet injection. Distillate-oil fuel.[6-11,17,18,23]

5-3. These figures show manufacturers' guaranteed NO_x emission levels of 42 ppmv for most natural gas-fired turbines, and from 42 to

75 ppmv for most oil-fired turbines. The percent reduction in NO_x emissions varies for each turbine, ranging from 60 to 94 percent depending upon each model's uncontrolled emission level and whether water or steam is injected.

Emissions data for water and steam injection are presented to show the effects of wet injection on NO_x emissions. These data show:

1. That NO_x emissions decrease with increasing WFR's; and
2. That NO_x emissions are higher for oil fuel than for natural gas.

From the available data, reduction efficiencies of 70 to over 85 percent were achieved. The emission data and WFRs shown for specific turbine models may not reflect the emission levels of current production models, since manufacturers periodically update or otherwise modify their turbines, thereby altering specific emissions levels.

Each emission test in the following figures consists of one or more data points. Where data points were obtained under similar conditions, they are grouped together and presented as a single test. For these cases, each data point, along with the arithmetic average of all of the data points, is shown.

The nomenclature used to identify the tests consists of two letters followed by a number. The first letter of the two-letter designator specifies the turbine type. These types are as follows:

Letter	Turbine type
A	Aircraft-derivative turbine
H	Heavy-duty turbine
T	Small and low-efficiency turbine (less than 7.5 MW output, less than 30 percent simple-cycle efficiency)

The second letter identifies the facility. The number identifies the number of tests performed at the facility. Tests performed at the same facility on different turbines or at different times have the same two-letter designator but are followed by different test numbers. The short horizontal lines represent the average of the test data.

Also presented are the available data on the turbine, wet controls, uncontrolled NO_x emissions, percent NO_x reduction, and fuel type. All of the data shown are representative of the performance of wet controls when the turbine is operated at base load or peak load. These loads represent the worst-case conditions for NO_x emission reduction. Information on the WFR, turbine model, efficiency, control type, and fuel are included with the emission test data.

Figures 5-4, 5-5, and 5-6 present the emission test data

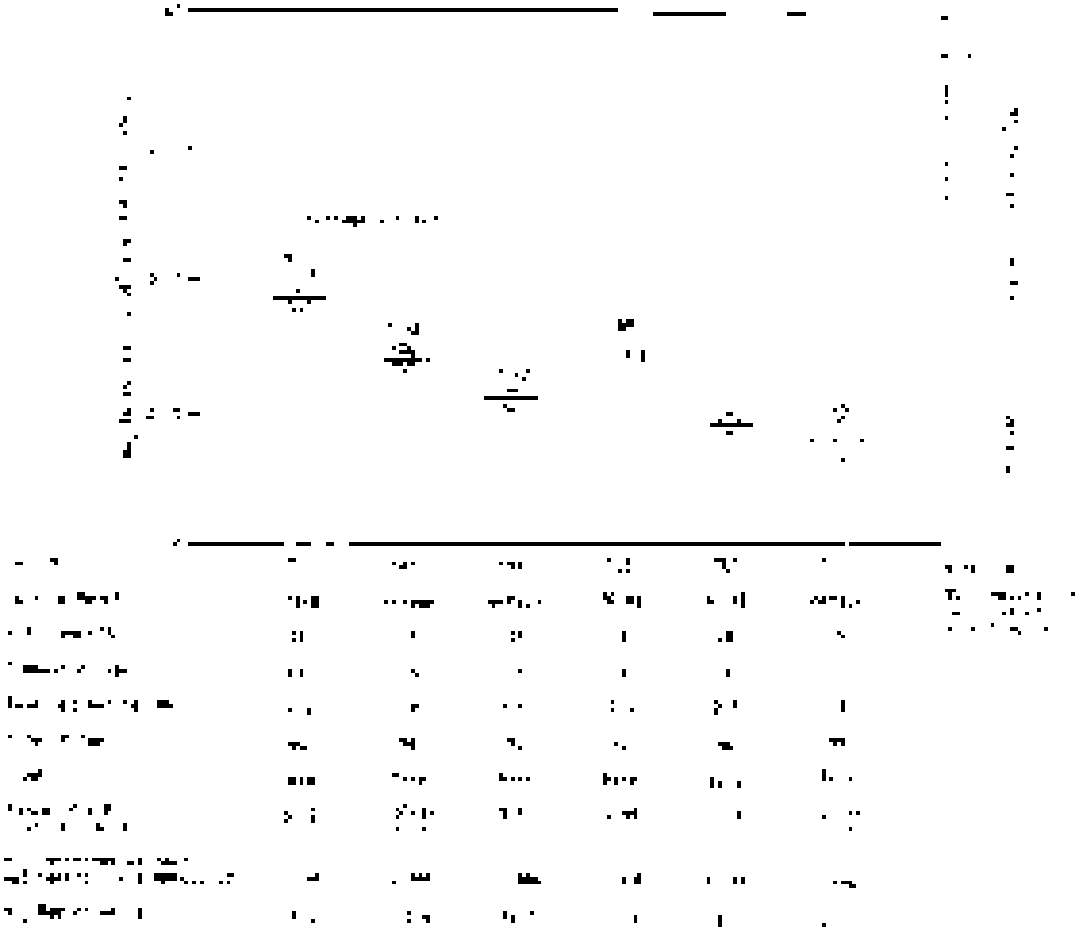


Figure 5-4. Nitrogen oxide emission test data for small, low-efficiency gas turbines with water injection firing natural gas.[27]

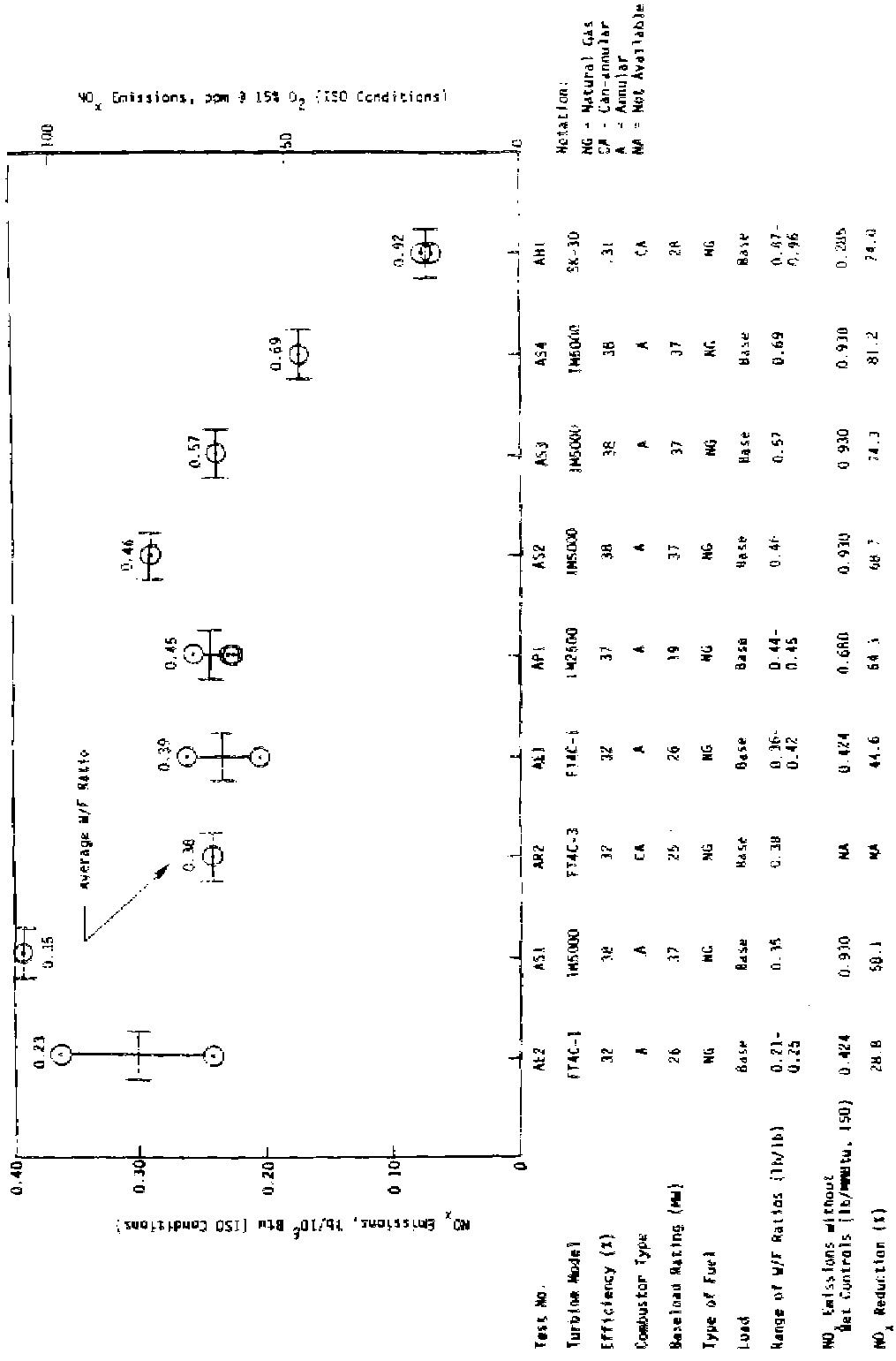


Figure 5-5. Nitrogen oxide emission test data for aircraft-derivative gas turbines with water injection firing natural gas.[27]

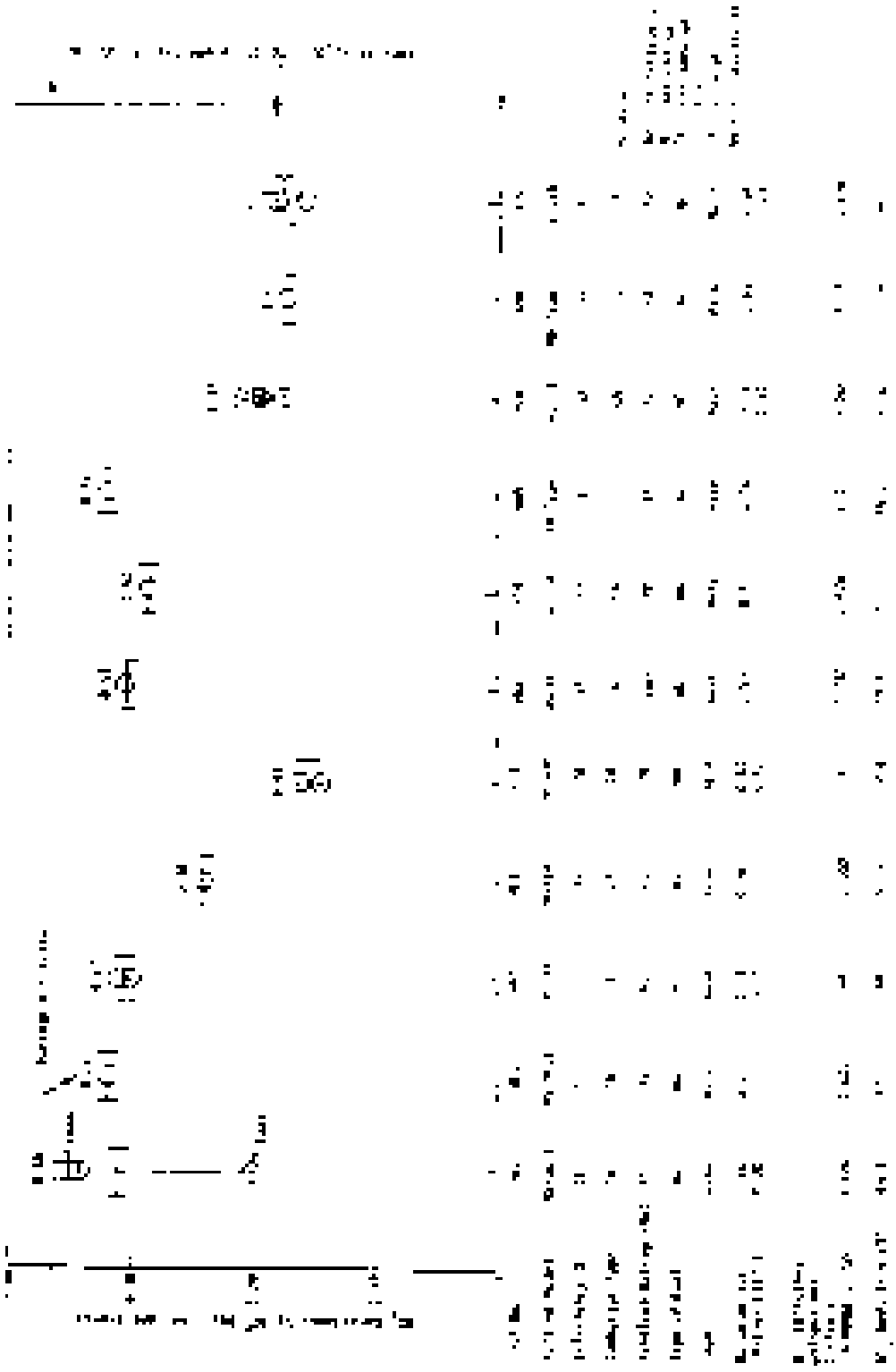
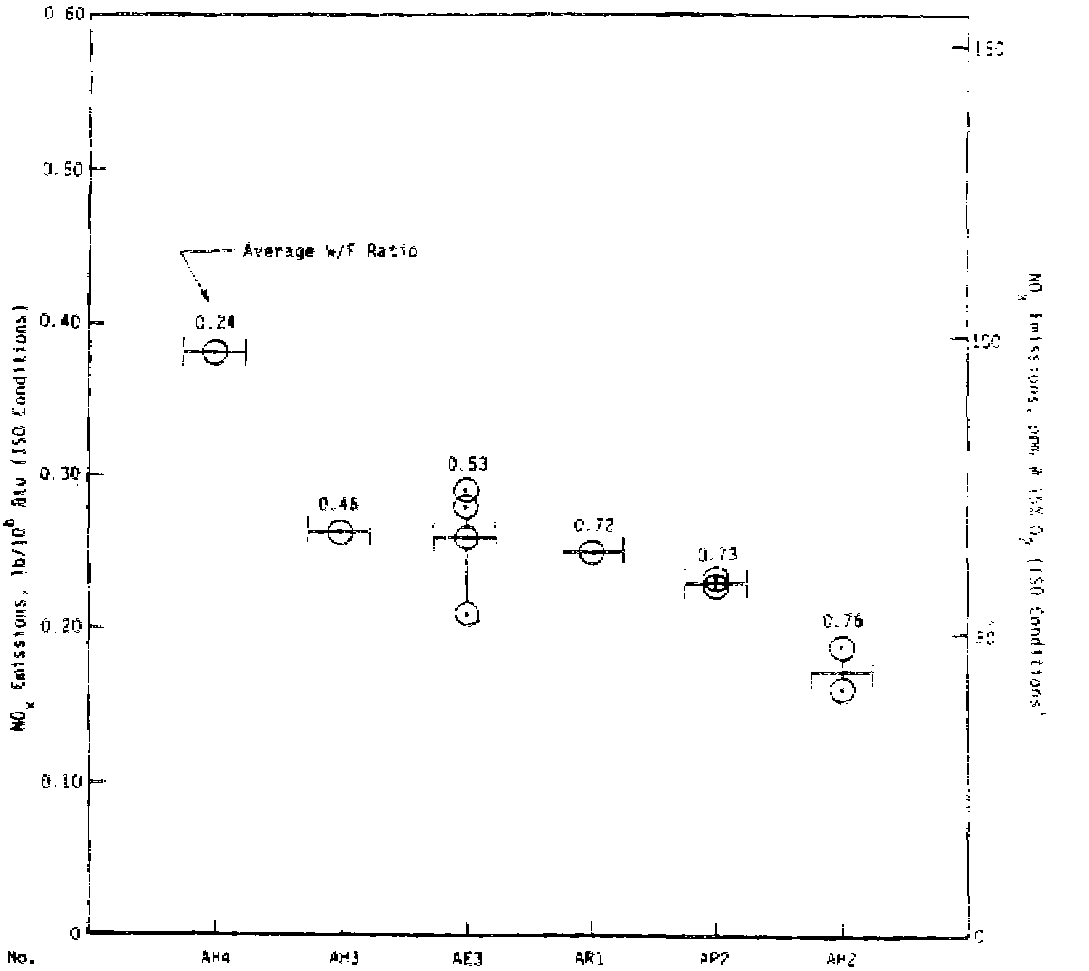


Figure 5-6. Nitrogen oxide emission test data for heavy-duty gas turbines with water injection firing natural gas.[27]

for water injection on turbines fired with natural gas. These turbines have NO_x emissions ranging from approximately 20 to 105 ppm with WFR's ranging from 0.16 to 1.32. Turbine sizes range from 2.8 to 97 MW. Based on these data, water injection is effective on all types of gas turbines and NO_x emission levels decrease as the WFR increases. However, some turbines require a higher WFR to meet a specific emission level. For example, the gas turbines at sites HH and HC (Figure 5-6) require much higher WFR's to achieve NO_x emission levels similar to the other gas turbine models shown. This particular gas turbine also has the highest uncontrolled NO_x emission levels. Conversely, the gas turbine at site AH, shown in Figure 5-5, has the lowest uncontrolled NO_x emission level and requires the least amount of water to achieve a given emission level. Uncontrolled NO_x emission levels vary for different turbine models depending upon design factors such as efficiency, firing temperature, and the extent of combustion controls incorporated in the combustor design (see Section 4.2.1.1). In general, aircraft-derivative and heavy-duty gas turbines require similar WFR's to achieve a specific emission level. Small, low-efficiency gas turbines require less water to achieve a specific emission level.

The NO_x emissions for turbines firing distillate oil are shown in Figures 5-7, 5-8, and 5-9. The data range from



Test No.	AH4	AH3	AE3	AR1	AP2	AH2
Turbine Model	SK-30	SK-30	FT4C-1	FT4C-3F	LM2500	SK-30
Efficiency (percent)	31	31	32	32	37	31
Combustor Type	CA	CA	CA	CA	A	CA
Base Load Rating (MW)	28	28	26	25	20	28
Type of Fuel	DO	DO	DO	DO	DO	DO
Load	Base	Base	Base	Base	Base	Base
Range of W/F Ratios (lb/lb)	0.24	0.46	0.51-0.55	0.72	0.73-0.73	0.68-0.84
NO_x Emissions without Wet Controls (lb/MMBtu, ISO)	0.559	0.559	0.787	0.840	1.37	0.559
NO_x Reduction (%)	32.0	52.8	66.8	70.5	83.4	58.9

Notation:
DO = distillate o
NG = natural gas
CA = can-annular
A = annular

Figure 5-7. Nitrogen oxide emission test data for aircraft-derivative gas turbines with water injection firing distillate oil.[27]

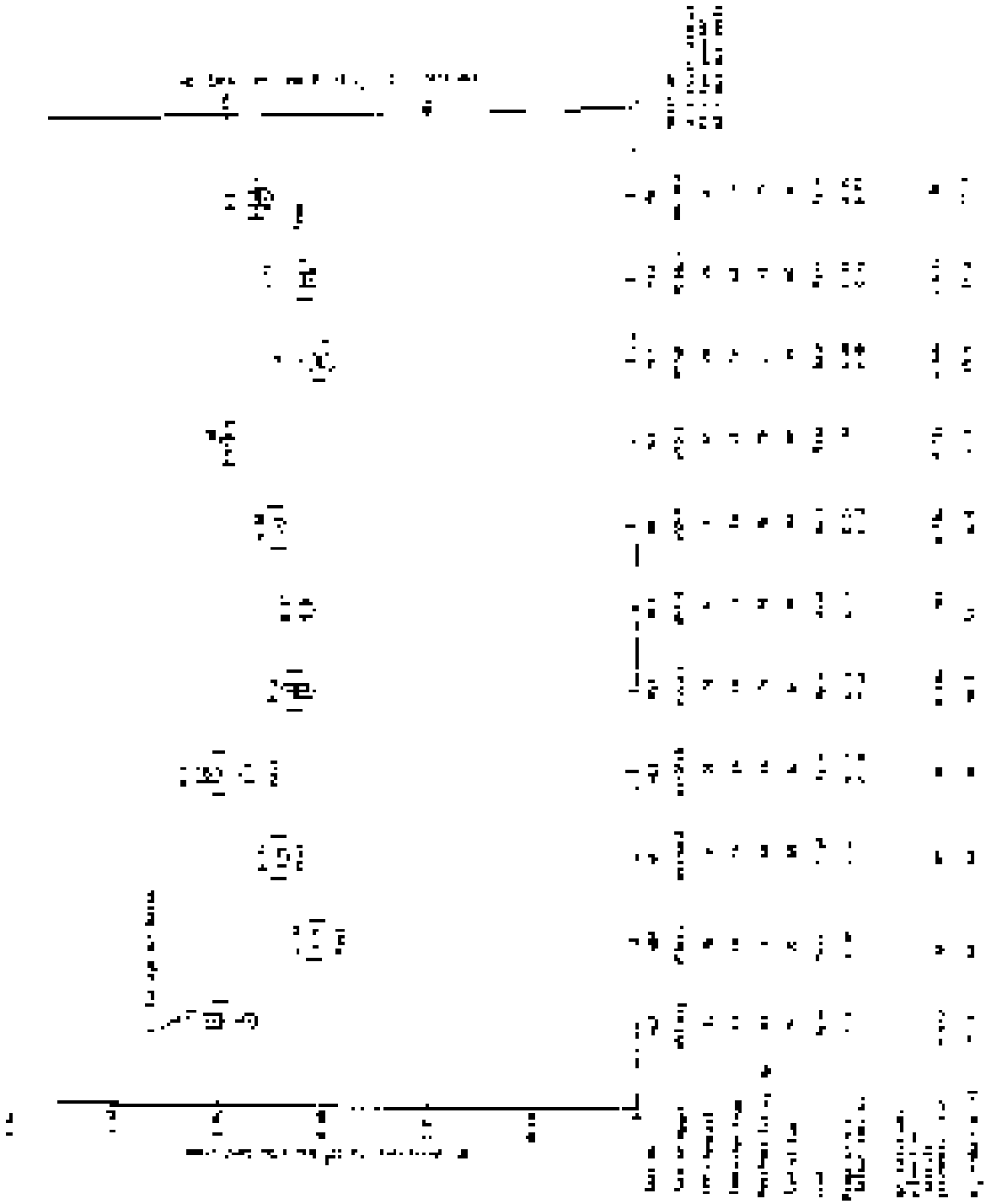


Figure 5-8. Nitrogen oxide emission test data for heavy-duty gas turbines with water injection and WFRs less than 0.5 and firing distillate oil.[27]

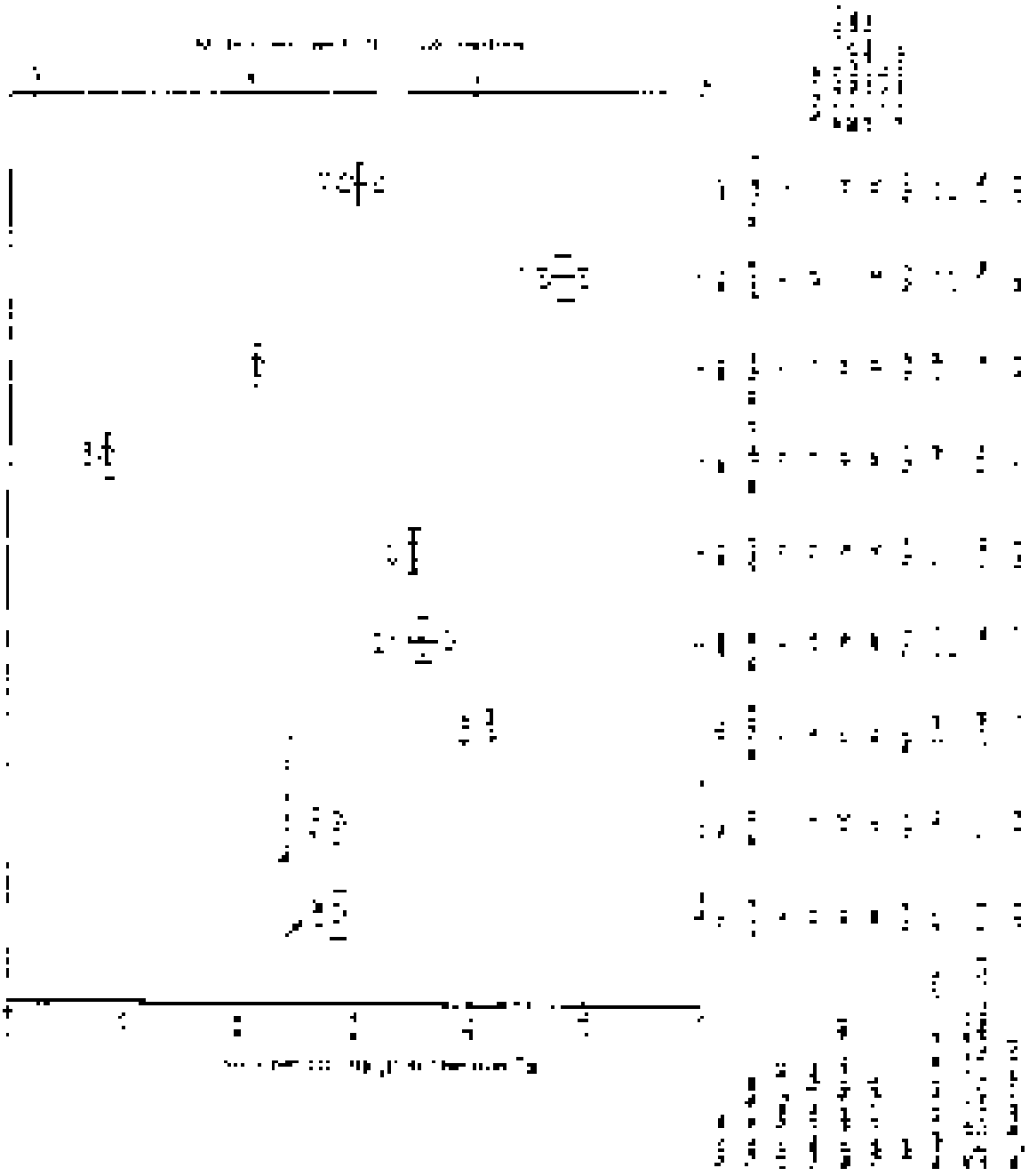


Figure 5-9. Nitrogen oxide emission test data for heavy-duty gas turbines with water injection and WFRs greater than 0.5 and firing distillate oil.[27]

approximately 30 to 135 ppm, with WFR's ranging from 0.24 to 1.31. The gas turbine sizes range from 19 to 95 MW. The data for distillate oil-fired turbines show the same general trends as the data for natural gas-fired turbines. Site HH (Figure 5-9)

again shows that higher WFR's are required due to the high uncontrolled NO_x emissions from this gas turbine. Also, by comparing the emission data for the distillate oil-fired turbines and natural gas-fired turbines, the data show that burning distillate oil requires higher WFR's than does burning natural gas for a given level of NO_x emissions. Higher WFR's are required because distillate oil produces higher uncontrolled NO_x levels than does natural gas (see Section 4.2.1.2).

The NO_x emission test data for steam injection are presented in Figures 5-10

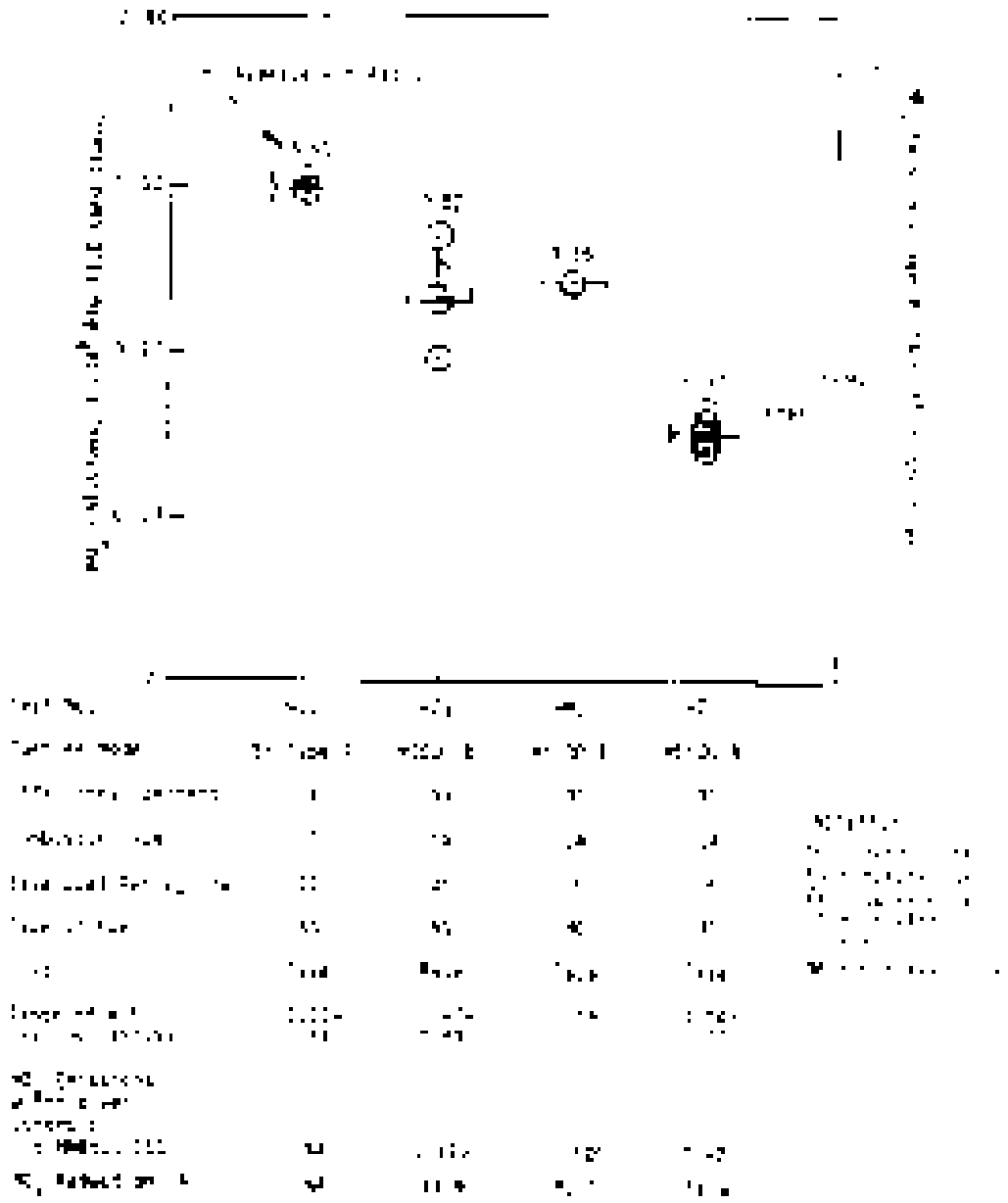


Figure 5-10. Nitrogen oxide emission test data for gas turbines with steam injection firing natural gas.[27]

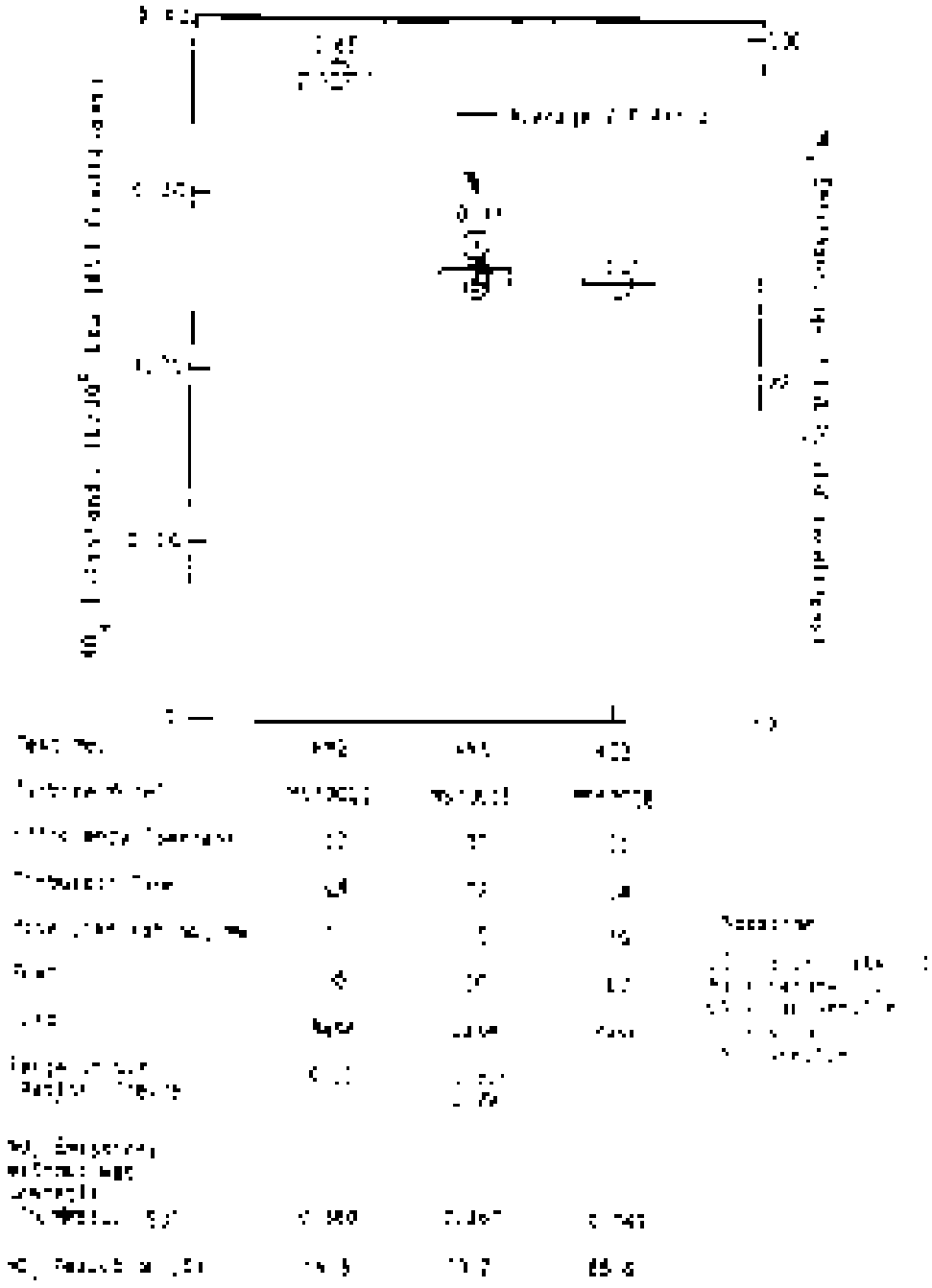


Figure 5-11. Nitrogen oxide emission test data for gas turbines with steam injection firing distillate oil.[27]

and 5-11 for natural gas-fired turbines and distillate oil-fired turbines, respectively. The turbines firing natural gas have NO_x emissions ranging from approximately 40 to 80 ppm, with WFR's ranging from 0.50 to 1.02. The gas turbine sizes range from 30 to 70 MW.

The NO_x emissions for turbines firing distillate oil range from approximately 65 to 95 ppm, with WFR's ranging from 0.65 to 1.01, and the gas turbine sizes tested were 36 and 70 MW. Fewer data points are available for steam injection than for water injection. However, the available data for both distillate oil-fired and natural gas-fired turbines show that NO_x emissions decrease as the steam-to-fuel ratio increases.

Reductions in NO_x emissions similar to water injection with oil-fired turbines have been achieved using water-in-oil emulsions. Results of emission tests for four turbines are shown in Table 5-7

TABLE 5-7. ACHIEVABLE GAS TURBINE NO_x EMISSION REDUCTIONS FOR OIL-FIRED TURBINES USING WATER-IN-OIL EMULSIONS[19]

				NO_x emissions, ppmv at 15 percent O_2		
Turbine manufacturer	Turbine model	Power output, MW	Water-to-fuel ratio	Uncontrolled	Controlled	Percent reduction
Turbo Power and Marine	A4	35	0.65	184	53	68
	A9	33	0.55	150	50	66
	A9	33	0.92	126	29	77
General Electric	MS5001	15	0.49	131	60	54

. The controlled NO_x emissions range from 29 to 60 ppmv, corresponding to NO_x reductions of 54 to 77 percent.[19] The controlled NO_x emission levels and percent reduction are consistent with those achieved using conventional water injection. Limited testing has shown that the emulsion achieves a given NO_x reduction level with a lower WFR than does a separate water injection arrangement. Test data for one oil-fired turbine showing a comparison of the WFR's for a water-in-oil emulsion versus a separate water injection system are shown in Figure 5-12

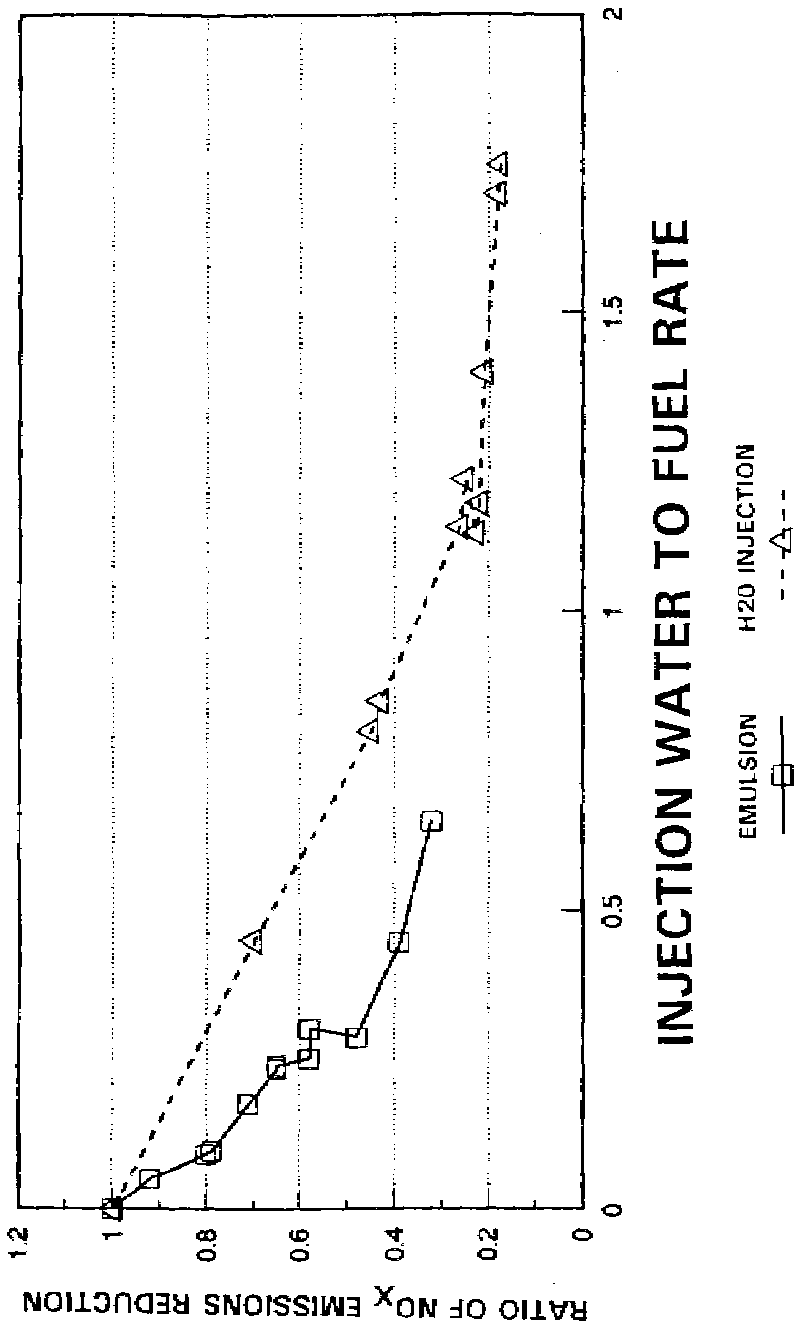


Figure 5-12. Comparison of the WFR requirement for water-in-oil emulsion versus separate water injection for an oil-fired turbine.[28]

. As shown here, NO_x reductions achieved by a water injection system at a WFR of 1.0 can be achieved by a water-in-oil emulsion at a WFR of 0.6.

On a mass basis, the reduction in NO_x emissions using water injection is shown in Table 5-8

TABLE 5-8. UNCONTROLLED NO_x EMISSIONS AND POTENTIAL NO_x REDUCTIONS FOR GAS TURBINES USING WATER INJECTION

Gas turbine model	Power output, MW[a]	NO_x emissions					
		Uncontrolled		Controlled		NO_x reduction	
		Gas fuel, lb/hr[b]	Oil fuel, lb/hr[b]	Gas fuel, lb/hr[b]	Oil fuel, lb/hr[b]	Gas fuel, tons/yr[c]	Oil fuel, tons/yr[c]
Saturn	1.1	6.4	9.9	2.8	4.1	14.3	23.3
Centaur	3.3	22.0	31.2	7.4	10.8	58.5	81.5
Centaur "H"	4.0	20.8	32.6	8.6	12.7	48.6	79.8
Taurus	4.5	24.7	37.6	9.4	13.9	61.1	94.9
Mars T-12000	8.8	69.4	107	17.0	24.9	210	329
Mars T-14000	10.0	85.4	NA[d]	18.7	NA[d]	267	NA[d]
501-KB5	4.0	31.6	48.5	8.9	12.2	90.9	145
570-K	4.9	22.7	41.0	9.8	15.2	51.8	103
571-K	5.9	24.2	44.0	10.4	16.3	55.1	111
LM1600	14.0	74.1	127	22.4	23.2	207	414
LM2500	22.7	146	301	36.4	37.9	438	1,050
LM5000	34.5	232	474	54.5	56.6	710	1,670
LM6000	43.0	310	609	61.3	63.5	996	2,180
MS5001P	26.8	181	274	55.5	87.4	503	747
MS6001B	39.0	250	459	73.2	116	704	1,370
MS7001E	84.7	544	822	154	243	1,560	2,320
MS7001F	161	1,290	2,190	267	417	4,090	7,090
MS9001E	125	810	1,320	219	369	2,370	3,820
MS9001F	229	1,850	3,150	382	600	5,850	10,200
GT8	47.4	899	1,440	54.1	92.3	3,380	5,410
GT10	22.6	143	196	24.6	42.6	472	614
GT11N	83.3	1,350	1,990	99.0	154	5,060	7,334
GT35	16.9	214	264	30.9	31.9	730	929
251B11/12	49.2	453	741	89.5	141	1,450	2,400
501D5	109	843	1,120	115	196	2,910	3,710
V84.2	105	858	1,570	176	190	2,730	5,520
V94.2	153	1,250	2,290	335	276	3,650	8,050
V64.3	61.5	859	1,290	176	188	2,740	4,390
V84.3	141	1,930	2,910	395	426	6,150	9,920
V94.3	204	2,790	4,170	571	611	8,890	14,200

[a]Power output at ISO conditions, without wet injection, with natural gas fuel.
[b]Based on ppmv levels shown in Tables 5-5 and 5-6. See Appendix A for conversion from ppmv to lb/hr.
[c]Based on 8,000 hours operation per year.
[d]Data not available.

; Table 5-9 shows uncontrolled NO$_x$ emissions and potential NO$_x$ reduction.

TABLE 5-9. UNCONTROLLED NO$_x$ EMISSIONS AND POTENTIAL NO$_x$ REDUCTIONS FOR GAS TURBINES USING STEAM INJECTION

Gas turbine model	Power output, MW[a]	NO$_x$ emissions					
		Uncontrolled		Controlled		NO$_x$ reduction	
		Gas fuel, lb/hr[b]	Oil fuel, lb/hr[b]	Gas fuel, lb/hr[b]	Oil fuel, lb/hr[b]	Gas fuel, tons/yr[c d]	Oil fuel, tons/yr[c d]
Saturn	1.1	6.4	9.9	6.4	9.9	0	0
Centaur	3.3	22.0	31.2	22.0	31.2	0	0
Centaur "H"	4.0	20.8	32.6	20.8	32.6	0	0
Taurus	4.5	24.7	37.6	24.7	37.6	0	0
Mars T-12000	8.8	69.4	107	69.4	107	0	0
501-KB5	4.0	31.6	48.5	8.6	48.5	194	0
570-K	4.9	22.7	41.0	22.7	41.0	0	0
571-K	5.9	24.2	44.0	24.2	44.0	0	0
LM1600	14.0	74.1	127	13.0	40.5	245	345
LM2500	22.7	146	301	21.2	66.0	499	938
LM5000	34.5	232	474	31.7	145	802	1,320
LM6000	43.0	310	609	35.6	162	1,100	1,790
MS5001P	26.8	181	274	54.1	85.3	508	755
MS6001B	39.0	250	459	71.4	113	711	1,380
MS7001E	84.7	544	822	150	237	1,580	2,340
MS7001F	161	1,290	2,190	260	407	4,110	7,130
MS9001E	125	810	1,320	214	360	2,390	3,850
MS9001F	229	1,850	3,150	373	585	5,890	10,200
GT8	47.4	899	1,440	61.2	129	3,350	5,260
GT10	22.6	143	196	40.4	41.6	410	618
GT11N	83.3	1,350	1,990	147	151	4,830	7,350
GT35	16.9	214	264	43.1	44.4	681	878
251B11/12	49.2	453	741	52.0	88.6	1,600	2,610
501D5	109	843	1,120	112	191	2,920	3,730
V84.2	105	858	1,570	225	242	2,530	5,310
V94.2	153	1,250	3,290	327	353	3,690	7,740
V64.3	61.5	859	1,290	171	184	2,750	4,410
V84.3	141	1,930	2,910	386	415	6,190	9,960
V94.3	204	2,790	4,170	557	596	8,940	14,300

[a]Power output at ISO conditions, without wet injection, with natural gas fuel.
[b]Based on ppmv levels shown in Tables 5-5 and 5-6. See Appendix A for conversion from ppmv to lb/hr.

As an example, a 21.8 MW turbine burning natural gas fuel can reduce NO_x emissions by 452 tons/yr (8,000 hours operation) using water injection and 511 tons/yr using steam injection. This same turbine burning oil fuel will reduce annual NO_x emissions by 1,040 tons using water injection and by 925 tons using steam injection.

5.1.5 Impacts of Wet Controls on CO and HC Emissions

While carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines, water injection may increase these emissions. Figure 5-13

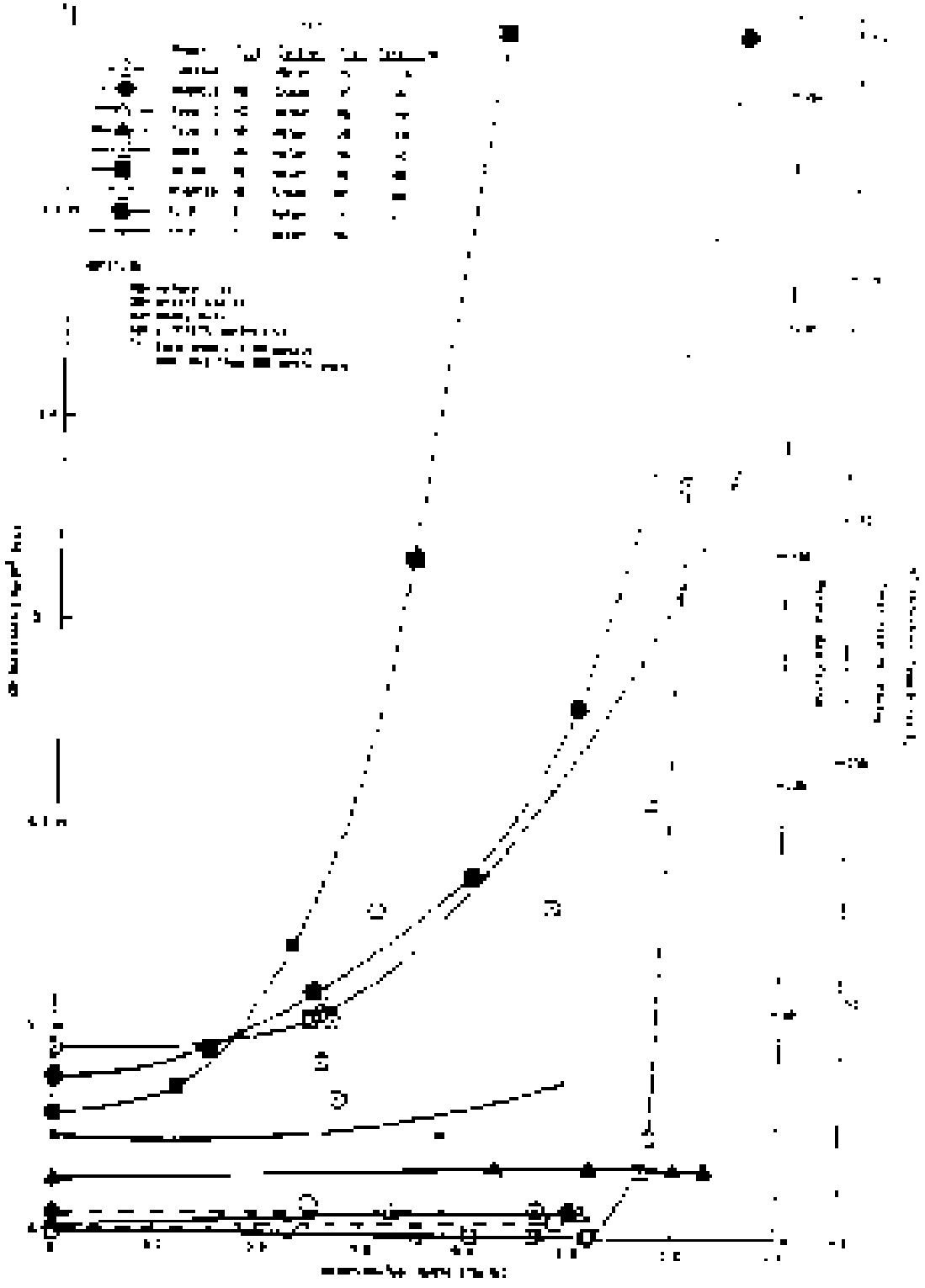


Figure 5-13. Effect of wet injection on CO emissions.[29]

shows the impact of water injection on CO emissions for several production gas turbines. In many turbines, CO emissions increase as the WFR increases, especially at WFR's above 0.8. Steam injection also increases CO emissions at relatively high WFR's, but the impact is less than that of water injection.[29,30]

Water and steam injection also increase HC emissions, but to a lesser extent than CO emissions.[29,30] The effect of water injection on HC emissions for one turbine is shown in

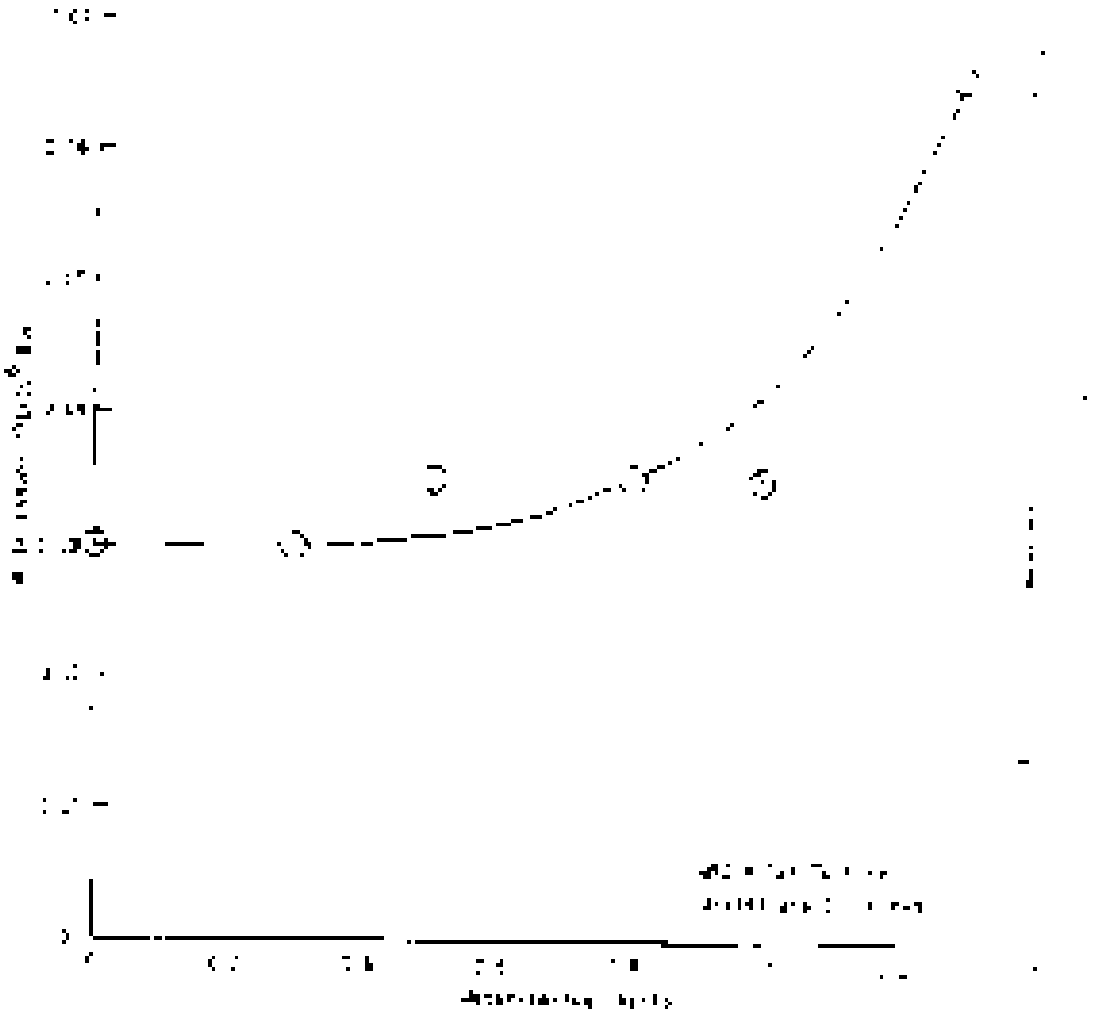


Figure 5-14. Effect of water injection on HC emissions for one turbine model.[29]

Figure 5-14. Like CO emissions, hydrocarbon emissions increase at WFR's above 0.8.

For applications where the water or steam injection rates required for NO_x emission reductions result in excess CO and/or HC emissions, it may be possible to select an alternative turbine and/or fuel with a relatively flat CO curve, as indicated in Figure 5-13. Another alternative is an oxidation catalyst to reduce these emissions. This oxidation catalyst is an add-on control device that is placed in the turbine exhaust duct or HRSG and serves to oxidize CO and HC to H_2O and CO_2. The catalyst material is usually a precious metal (platinum, palladium, or rhodium), and oxidation efficiencies of 90 percent or higher can be achieved. The oxidation process takes place spontaneously, without the requirement for introducing reactants (such as ammonia) into the flue gas stream.[31]

5.1.6 Impacts of Wet Controls on Gas Turbine Performance

Wet controls affect gas turbine performance in two ways: power output increases and efficiency decreases. The energy from the added mass flow and heat capacity of the injected water or steam can be recovered in the turbine, which results in an increase in power output. For water injection, the fuel energy required to vaporize the water in the turbine combustor, however, results in a net penalty to the overall efficiency of the turbine. For steam injection, there is an energy penalty associated with generating the steam, which results in a net penalty to the overall cycle efficiency. Where the steam source is exhaust heat, which would otherwise be exhausted to the atmosphere, the heat recovery results in a net gain in gas turbine efficiency.[32] The actual efficiency reduction associated with wet controls is specific to each turbine and the actual WFR required to meet a specific NO_x reduction. The overall efficiency penalty increases with increasing WFR and is usually higher for water injection than for steam injection due to the heat of vaporization associated with water. The impacts on output and efficiency for one manufacturer's gas turbines are shown in Table 5-10.

TABLE 5-10. REPRESENTATIVE WATER/STEAM INJECTION IMPACTS ON GAS TURBINE PERFORMANCE FOR ONE MANUFACTURER'S HEAVY-DUTY TURBINES[33]

NO_x level, ppmv	Water/fuel ratio	Percent overall efficiency change	Percent output change[a]	Remarks
75 NSPS	0.5	-1.8	+3	Oil-fired, simple cycle, water injection
42	1.0	<-3	+5	Natural gas, simple cycle, water injection
42	1.2	-2	+5	Natural gas, combined cycle, steam injection
25	1.2	-4	+6	Natural gas, water injection, multinozzle combustor
25	1.3	-3	+5.5	Natural gas, steam injection, combined cycle (Frame 6 turbine model)

[a]Compared with no injection.

5.1.7 Impacts of Wet Controls on Gas Turbine Maintenance

Water injection increases dynamic pressure oscillation activity in the turbine combustor.[33] This activity can, in some turbine models, increase erosion and wear in the hot section of the turbine, thereby increasing maintenance requirements. As a result, the turbine must be removed from service more frequently for inspection and repairs to the hot section components. A summary of the maintenance impacts as provided by manufacturers is shown in Table 5-11.

TABLE 5-11. IMPACTS OF WET CONTROLS ON GAS TURBINE MAINTENANCE USING NATURAL GAS FUEL[5-11,17,24]

Manufacturer/Model	NO_x emissions, ppmv @ 15% O_2			Inspection interval, hours		
	Standard combustor	Water injection	Steam injection	Standard	Water injection	Steam injection
General Electric						
LM1600	133	42/25	25	25,000	16,000[a]	25,000
LM2500	174	42/25	25	25,000	16,000[a]	25,000
LM5000	185	42/25	25	25,000	16,000[a]	25,000
LM6000	220	42/25	25	25,000	16,000[a]	25,000
MS5001P	142	42	42	12,000	6,000	6,000
MS6001B	148	42	42	12,000	6,000	8,000
MS7001E	154	42	42	8,000	6,500	8,000
MS7001F	179	42	42	8,000	8,000	8,000
MS9001E	176	42	42	8,000	6,500	8,000
MS9001F	176	42	42	8,000	8,000	8,000
Asea Brown Boveri						
GT10	150	25	42	80,000[b]	80,000[b]	80,000[b]
GT8	430	25	29	24,000	24,000	24,000
GT11N	400	25	25	24,000	24,000	24,000
GT35	300	42	60	80,000[b]	80,000[b]	80,000[b]
Siemens Power Corp.						
V84.2	212	42	55	25,000	25,000	25,000
V94.2	212	55	55	25,000	25,000	25,000
V64.3	380	75	75	25,000	25,000	25,000
V84.3	380	75	75	25,000	25,000	25,000
V94.3	380	75	75	25,000	25,000	25,000
Solar Turbines, Inc.						
T-1500 Saturn	99	42	NA[c]	NA[d]	NA[d]	NA[c]
T-4500 Centaur	150	42	NA[c]	NA[d]	NA[d]	NA[c]
Type H Centaur	105	42	NA[c]	NA[d]	NA[d]	NA[c]
Taurus	114	42	NA[c]	NA[d]	NA[d]	NA[c]
T-12000 Mars	178	42	NA[c]	NA[d]	NA[d]	NA[c]
T-14000 Mars	199	42	NA[c]	NA[d]	NA[d]	NA[c]
Allison/General Motors						
501-KB5	155	42	NA[c]	25,000	17,000	NA[d]
501-KC5	174	42	NA[c]	30,000	22,000	NA[d]
501-KH	155	42	25	25,000	17,000	20,000
570-K	101	42	NA[c]	20,000	12,000	NA[d]
571-K	101	42	NA[c]	20,000	12,000	NA
Westinghouse						
251B11/12	220	42	25	8,000	8,000	8,000
501D5	190	25	25	8,000	8,000	8,000

[a]Applies only to 25 ppmv level. No impact for 42 ppmv.
[b]This interval applies to time between overhaul (TBO).
[c]Steam injection is not available for this model.
[d]Data not available.

As this table shows, the maintenance impact, if any, varies from manufacturer to manufacturer and model to model. Some manufacturers stated that there is no impact on maintenance intervals associated with water or steam injection for their turbine models. Data were provided only for operation with natural gas.

5.2 COMBUSTION CONTROLS

The formation of both thermal NO_x and fuel NO_x depends upon combustion conditions, so modification of these conditions affects NO_x formation. The following combustion modifications are used to control NO_x emission levels:

1. Lean combustion;
2. Reduced combustor residence time;
3. Lean premixed combustion; and
4. Two-stage rich/lean combustion.

These combustion modifications can be applied singly or in combination to control NO_x emissions.

The mechanisms by which each of these techniques reduce NO_x formation, their applicability to new gas turbines, and the design or operating factors that influence NO_x reduction performance are discussed below by control technique.

5.2.1 Lean Combustion and Reduced Combustor Residence Time

5.2.1.1 Process Description. Gas turbine combustors were originally designed to operate with a primary zone equivalence ratio of approximately 1.0. (An equivalence ratio of 1.0 indicates a stoichiometric ratio of fuel and air. Equivalence ratios below 1.0 indicate fuel-lean conditions, and ratios above 1.0 indicate fuel-rich conditions.) With lean combustion, the additional excess air cools the flame, which reduces the peak flame temperature and reduces the rate of thermal NO_x formation.[34]

In all gas turbine combustor designs, the high-temperature combustion gases are cooled with dilution air to an acceptable temperature prior to entering the turbine. This dilution air rapidly cools the hot gases to temperatures below those required for thermal NO_x formation. With reduced residence time combustors, dilution air is added sooner than with standard combustors. Because the combustion gases are at a high temperature for a shorter time, the amount of thermal NO_x formed decreases.[34]

Shortening the residence time of the combustion products at high temperatures may result in increased CO and HC emissions if

no other changes are made in the combustor. In order to avoid increases in CO and HC emissions, combustors with reduced residence time also incorporate design changes in the air distribution ports to promote turbulence, which improves fuel/air mixing and reduces the time required for the combustion process to be completed. These designs may also incorporate fuel/air premixing chambers. Therefore, the differences between reduced residence time combustors and standard combustors are the placement of the air ports, the design of the circulation flow patterns in the combustor, and a shorter combustor length.[34]

5.2.1.2 Applicability. Lean primary zone combustion and reduced residence time combustion have been applied to annular, can-annular, and silo combustor designs.[35-37] Almost all gas turbines presently being manufactured incorporate lean combustion and/or reduced residence time to some extent in their combustor designs, incorporating these features into production models since 1975.[38,39] However, the varying uncontrolled NO_x emission levels of gas turbines shown in Figures 5-2 and 5-3 indicate that these controls are not incorporated to the same degree in every gas turbine and may be limited in some turbines by the quantity of dilution air available for lean combustion.

Lean primary zone and reduced residence time are most applicable to low-nitrogen fuels, such as natural gas and distillate oil fuels. These modifications are not effective in reducing fuel NO_x.[40]

5.2.1.3 Factors Affecting Performance. For a given combustor, the performance of lean combustion is directly affected by the primary zone equivalence ratio. As shown in Figure 4-2, the further the equivalence ratio is reduced below 1.0, the greater the reduction in NO_x emissions. However, if the equivalence ratio is reduced too far, CO emissions increase and flame stability problems occur.[41] This emissions tradeoff effectively limits the amount of NO_x reduction that can be achieved by lean combustion alone.

For combustors with reduced residence time, the amount of NO_x emission reduction achieved is directly related to the decrease in residence time in the high-temperature flame zone.

5.2.1.4 Achievable NO_x Emission Levels Using Lean Combustion and Reduced Residence Time Combustors. Lean combustion reduces NO_x emissions, and when used in combination with reduced residence time, NO_x emissions are further reduced. Figure 5-1

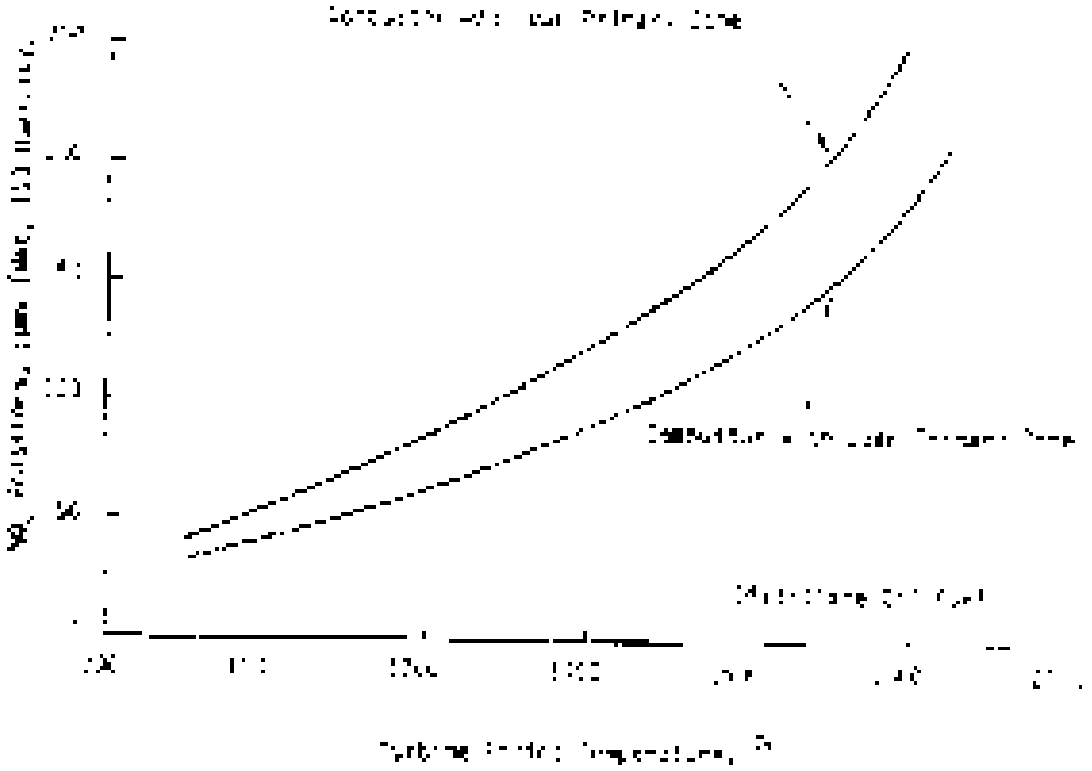


Figure 5-15. Nitrogen oxide emissions versus turbine firing temperature for combustors with and without a lean primary zone.[42]

5 shows a comparison of NO_x emissions from a combustor with a lean primary zone and NO_x emissions from the same combustor without a lean primary zone. At the same firing temperature, NO_x emissions reductions of up to 30 percent are achieved using lean primary zone combustion without increasing CO emissions. Reducing the residence time at elevated temperatures reduces NO_x emissions. One test at 1065°C (1950°F) yielded a reduction in NO_x emissions of 40 percent by reducing the residence time. Carbon monoxide emissions increased from less than 10 to approximately 30 ppm.[42-45]

5.2.2 Lean Premixed Combustors

5.2.2.1 Process Description. In a conventional combustor, the fuel and air are introduced directly into the combustion zone and fuel/air mixing and combustion take place simultaneously. Wide variations in the air-to-fuel ratio (A/F) exist, and combustion of localized fuel-rich pockets produces significant levels of NO_x emissions. In a lean premixed combustor design, the air and fuel is premixed at very lean A/F's prior to introduction into the combustion zone. The excess air in the lean mixture acts as a heat sink, which lowers combustion temperatures. Premixing results in a homogeneous mixture, which minimizes localized fuel-rich zones. The resultant uniform, fuel-lean mixture results in greatly reduced NO_x formation rates.[17]

To achieve NO_x levels below 50 ppmv, referenced to 15 percent O_2, the design A/F approaches the lean flammability limit. To stabilize the flame, ensure complete combustion, and minimize CO emissions, a pilot flame is incorporated into the combustor or burner design. In most designs, the relatively

small amount of air and fuel supplied to this pilot flame is not premixed and the A/F is nearly stoichiometric, so the pilot flame temperature is relatively high. As a result, NO_x emissions from the pilot flame are higher than from the lean premixed combustion.[46]

Virtually all gas turbine manufacturers have implemented lean premixed combustion development programs. Three manufacturers' designs that are available in production turbines are described below.

The first design uses a can-annular combustor and is shown in Figure 5-16

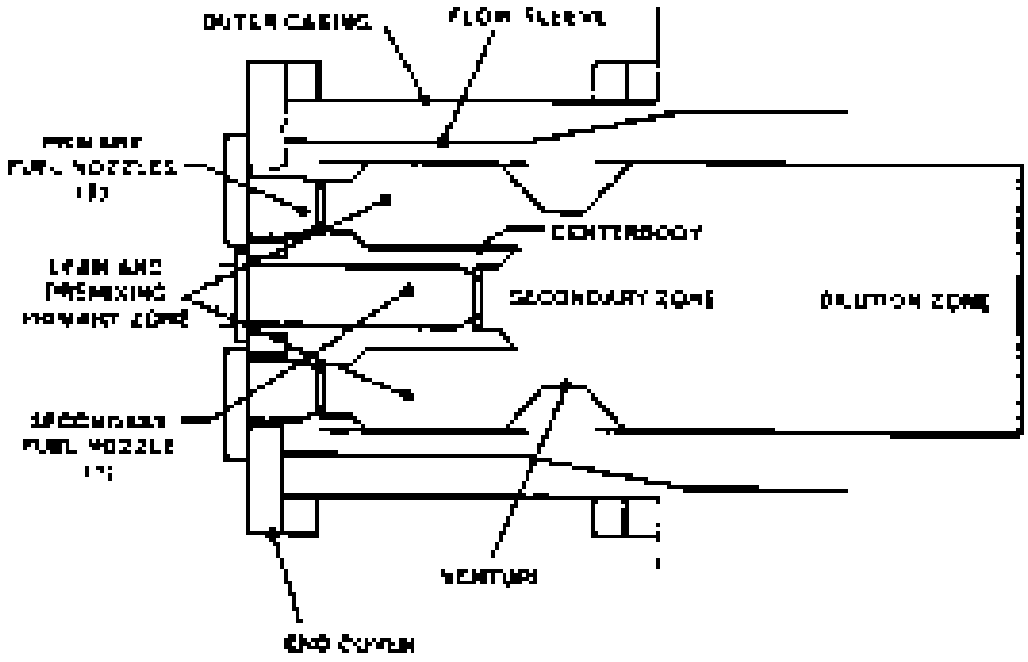


Figure 5-6. Cross-section of a lean premixed can-annular combustor.[47]

. This is a two-stage premixed combustor: the first stage is the portion of the combustor upstream of the venturi section and includes the six primary fuel nozzles; the second stage is the balance of the combustor and includes the single secondary fuel nozzle.[33]

The operating modes for this combustor design are shown in Figure 5-17. For ignition, warmup, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor.

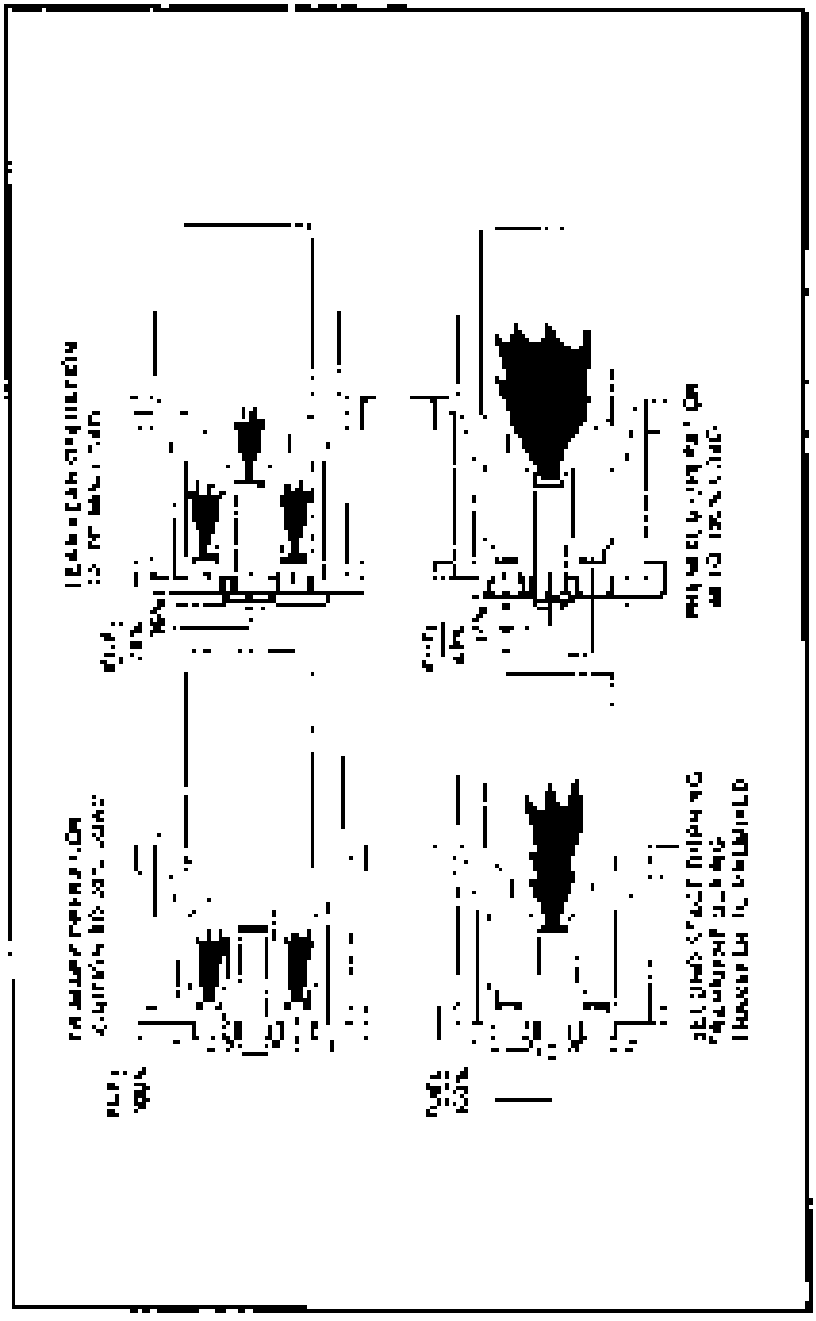


Figure 5-17. Operating modes for a lean premixed can-annular combustor.[33]

Flame is present only in the first stage, and the equivalence ratio is kept as low as stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. Again, the equivalence ratio is kept as low as possible in both stages to minimize NO_x emissions. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.[33]

For operation on distillate oil, fuel is introduced and burned only in the first stage for ignition and for loads up to approximately 50 percent. For loads greater than 50 percent, fuel is introduced and burned in both stages.[33]

Figure 5-18 shows a lean premixed combustor design used by another manufacturer for an annular combustor.

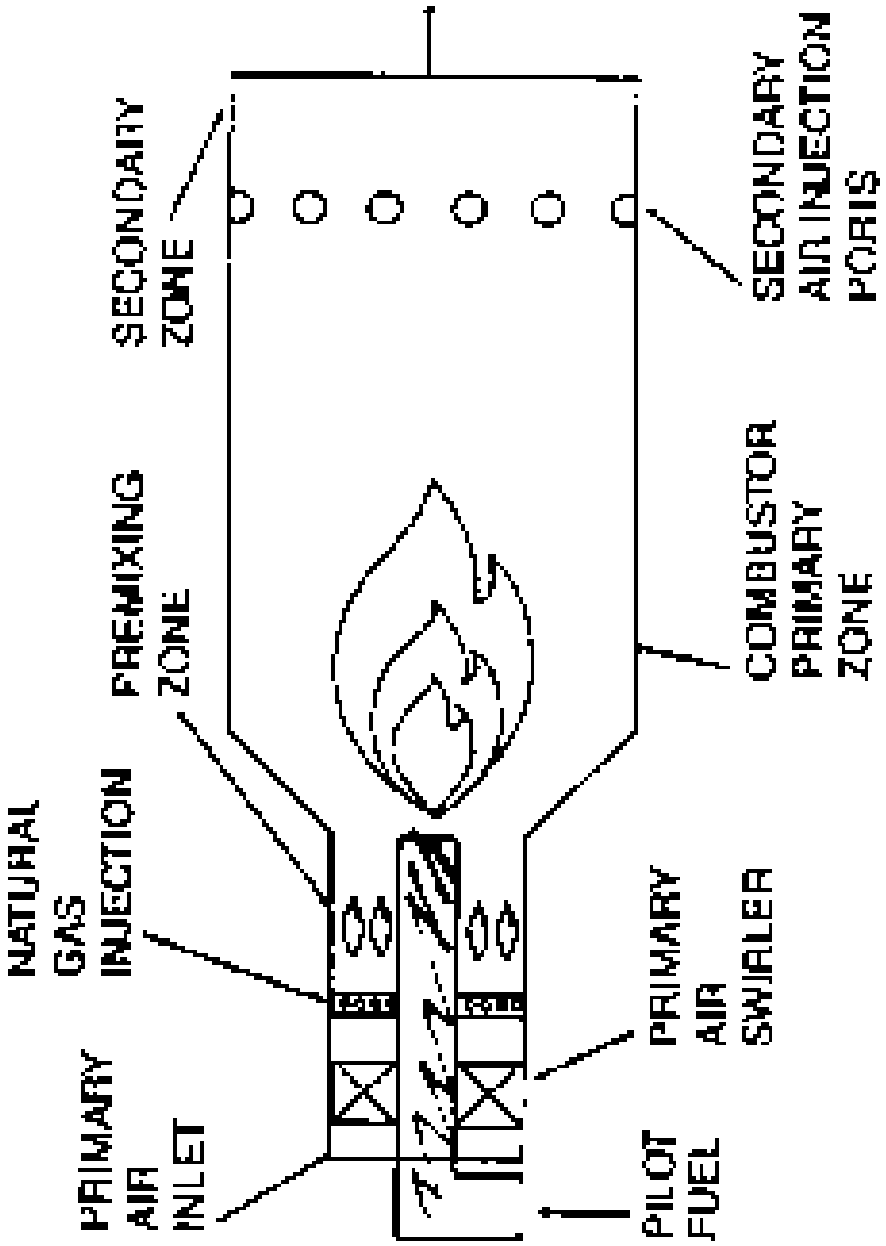


Figure 5-18. Cross-section of lean premixed annular combustion design.[47]

The air and fuel are premixed using a very lean A/F, and the resultant uniform mixture is delivered to the primary combustion zone where combustion is stabilized using a pilot flame. Using one or more mechanical systems to regulate the airflow delivered to the combustor, the premix mode is operable for output loads between 50 and 100 percent. Below 50 percent load, only the pilot flame is operating, and NO_x emissions levels are similar to those for conventional combustors.[46]

Another manufacturer's production low-NO_x design uses a silo combustor. Unlike the can-annular and annular designs, the silo combustor is mounted externally to the turbine and can therefore be modified without significantly affecting the rest of the turbine design, provided the mounting flange to the turbine is unchanged. In addition, this large combustion chamber is fitted with a ceramic lining that shields the metal surfaces from peak flame temperatures. This lining reduces the requirement for cooling air, so more air is available for the combustion process.[17]

This silo low-NO_x combustor design uses six burners, as shown in Figure 5-19

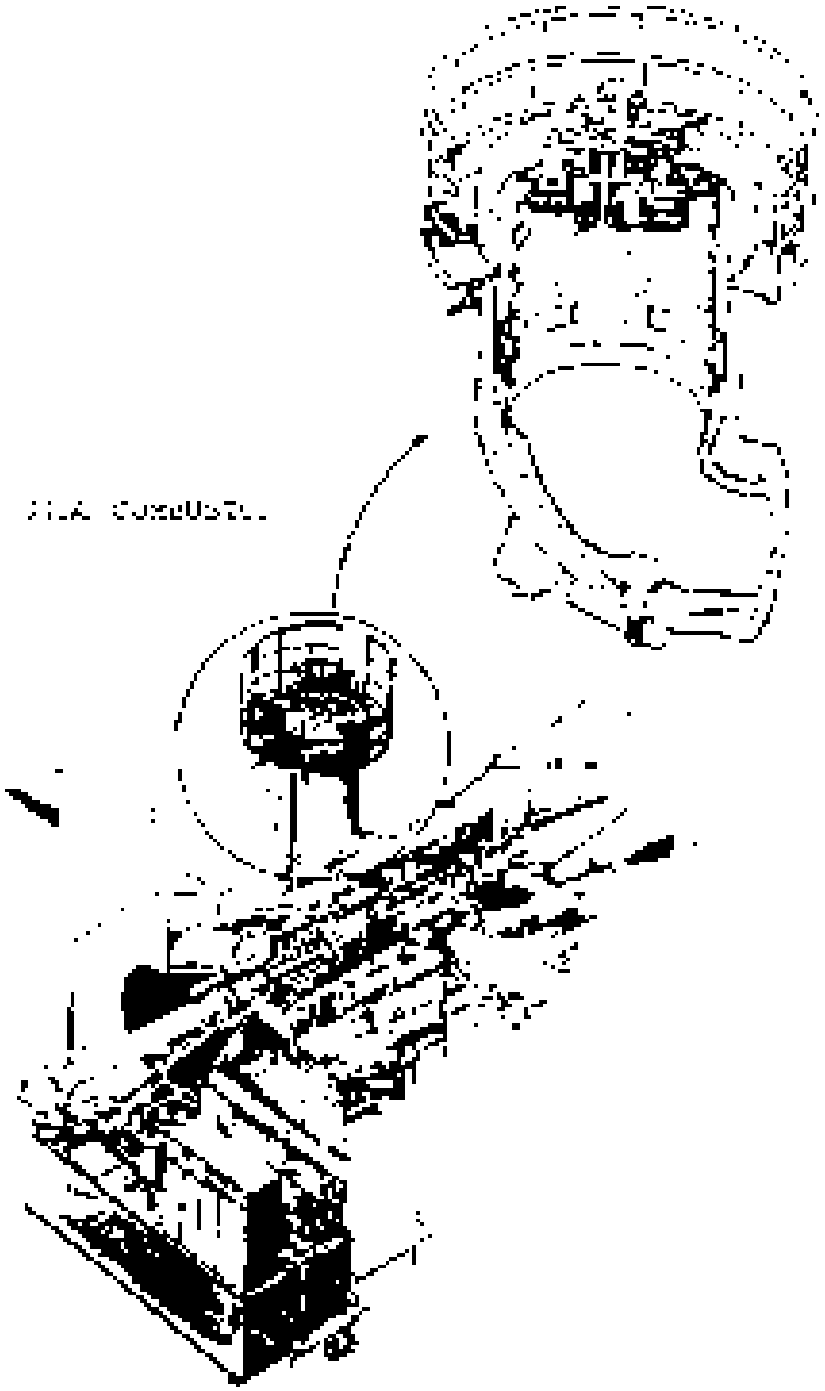


Figure 5-19. Cross-section of a low NO_x silo combustor.[35,48]

. For operation on natural gas, each burner serves to premix the air and fuel to deliver a lean and uniform mixture to the combustion zone. To achieve the lowest possible NO_x emissions, the A/F of the premixed gases is kept very near the lean flammability limit and a pilot flame is used to stabilize the overall combustion process. This burner design is shown in Figure 5-20

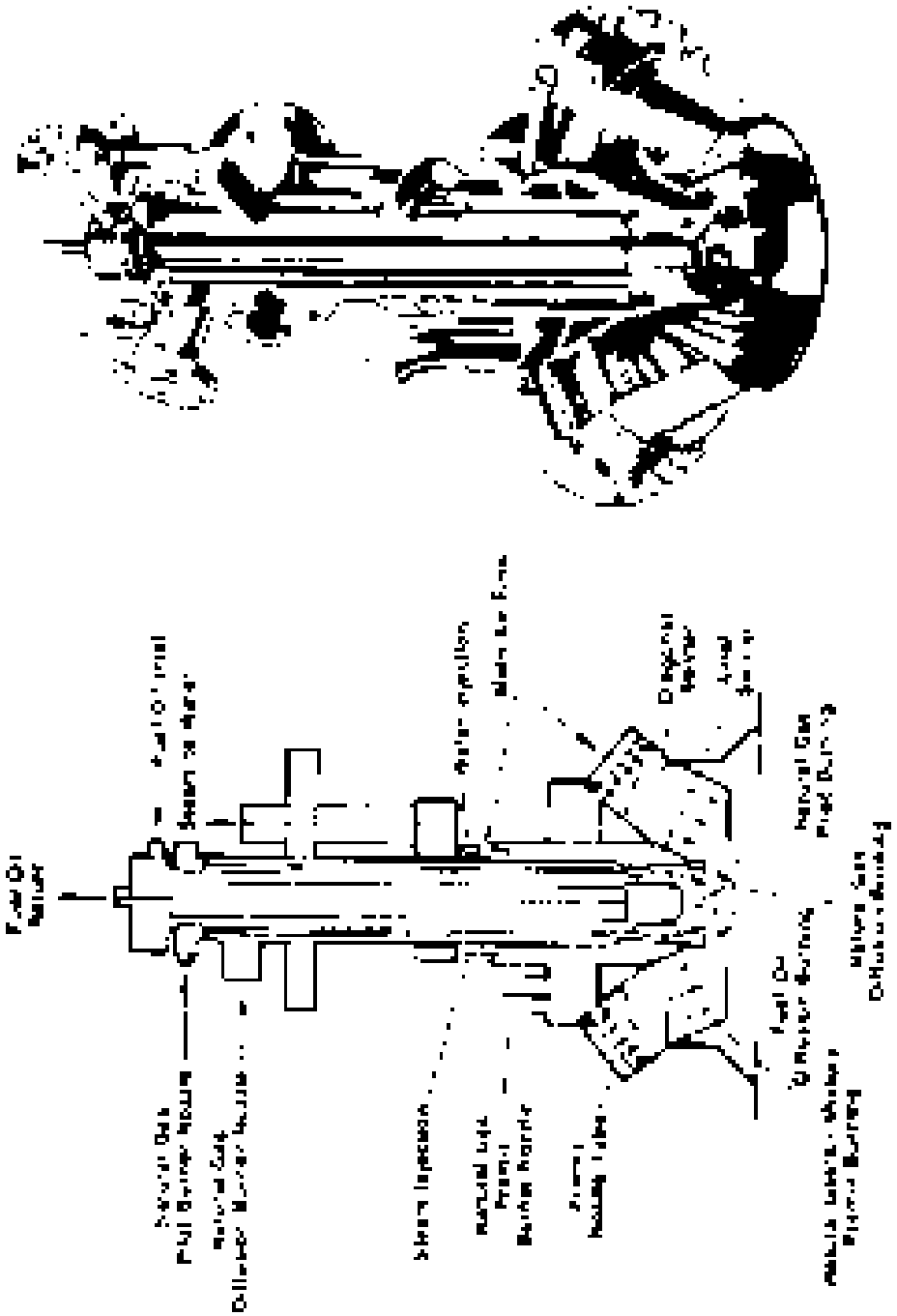


Figure 5-20. Low-NO_x burner for a silo combustor.[48]

. Like the can-annular design, the burner in the silo combustor cannot operate over the full power range of the gas turbine in the premix mode due to inability of the premix mode to deliver suitable A/F's at low power output levels. For this reason, the burners are designed to operate in a conventional diffusion burning mode at startup and low power outputs and switch to a premix burning mode at higher power output levels.

For operation on distillate oil with the current burner design, combustion occurs only in a diffusion mode and there is no premixing of air and fuel.

5.2.2.2 Applicability. As discussed in Section 5.2.2.1, lean premixed combustors apply to can-annular, annular, and silo combustors. This combustion modification is effective in reducing thermal NO_x emissions for both natural gas and distillate oil but is not effective on fuel NO_x. Therefore, lean premixed combustion is not as effective in reducing NO_x levels if high-nitrogen fuels are fired.[49]

The multiple operating modes associated with the percent operating load results in "stepped" NO_x emission levels. To date, low NO_x emission levels occur only at loads greater than 40 to 75 percent.

Lean premixed combustors currently are available for limited models from three manufacturers contacted for this study.[6,17,24] Two additional manufacturers project an availability date of 1993 or 1994 for lean premixed combustors for some turbine models.[11,50] All of these manufacturers state that these lean premixed combustors will be available for retrofit applications.

5.2.2.3 Factors Affecting Performance. The primary factors affecting the performance of lean, premixed combustors are A/F and the type of fuel. To achieve low NO_x emission levels, the A/F must be maintained in a narrow range near the lean flammability limit of the mixture. Lean premixed combustors are designed to maintain this A/F at rated load. At reduced load conditions, the fuel input requirement decreases. To avoid combustion instability and excessive CO emissions that would occur as the A/F reaches the lean flammability limit, all manufacturers' lean premixed combustors switch to a diffusion-type combustion mode at reduced load conditions, typically between 40 and 60 percent load. This switchover to a diffusion combustion mode results in higher NO_x emissions.

Natural gas produces lower NO_x levels than do oil fuels. The reasons for this are the lower flame temperature of natural gas and the ability to premix this fuel with air prior to

delivery into the second combustion stage. For operation on liquid fuels, currently available lean premixed combustor designs require water injection to achieve appreciable NO_x reduction.

5.2.2.4 Achievable NO_x Emission Levels. The achievable controlled NO_x emission levels for lean premixed combustors vary depending upon the manufacturer. At least three manufacturers currently guarantee NO_x emission levels of 25 ppmv, corrected to 15 percent O_2 for most or all of their gas turbines for operation on natural gas fuel without wet injection.[6,17,24] Each of these three manufacturers has achieved controlled NO_x emission levels of less than 10 ppmv at one or more installations in the United States and/or Europe and guarantee this NO_x level for a limited number of their gas turbine models.[51] All three manufacturers offer gas turbines in the 10+ MW (13,400 hp+) range and anticipate that guaranteed NO_x emission levels of 10 ppmv or less will be available for all of their gas turbines for operation on natural gas fuel in the next few years. These low-NO_x combustor designs apply to new turbines and existing installation retrofits.

For gas turbines in the range of 10 MW (13,400 hp) and under, one gas turbine manufacturer offers a guarantee for its lean premixed combustor, without wet injection, of 42 ppmv using natural gas fuel for two of its turbine models for 1994 delivery. This manufacturer states that a controlled NO_x emission level of 25 ppmv has been achieved by in-house testing, and this 25 ppmv level firing natural gas fuel is the goal for all of its gas turbine models, for both new equipment and retrofit applications.[50]

These controlled NO_x emission levels of 9 to 42 ppmv correspond to full output load; at reduced loads, the NO_x levels increase, often in "stepped" fashion in accordance with changes in combustor operation from premixed mode to conventional or diffusion-mode operation (see Section 5.2.2.3). Figure 5-21

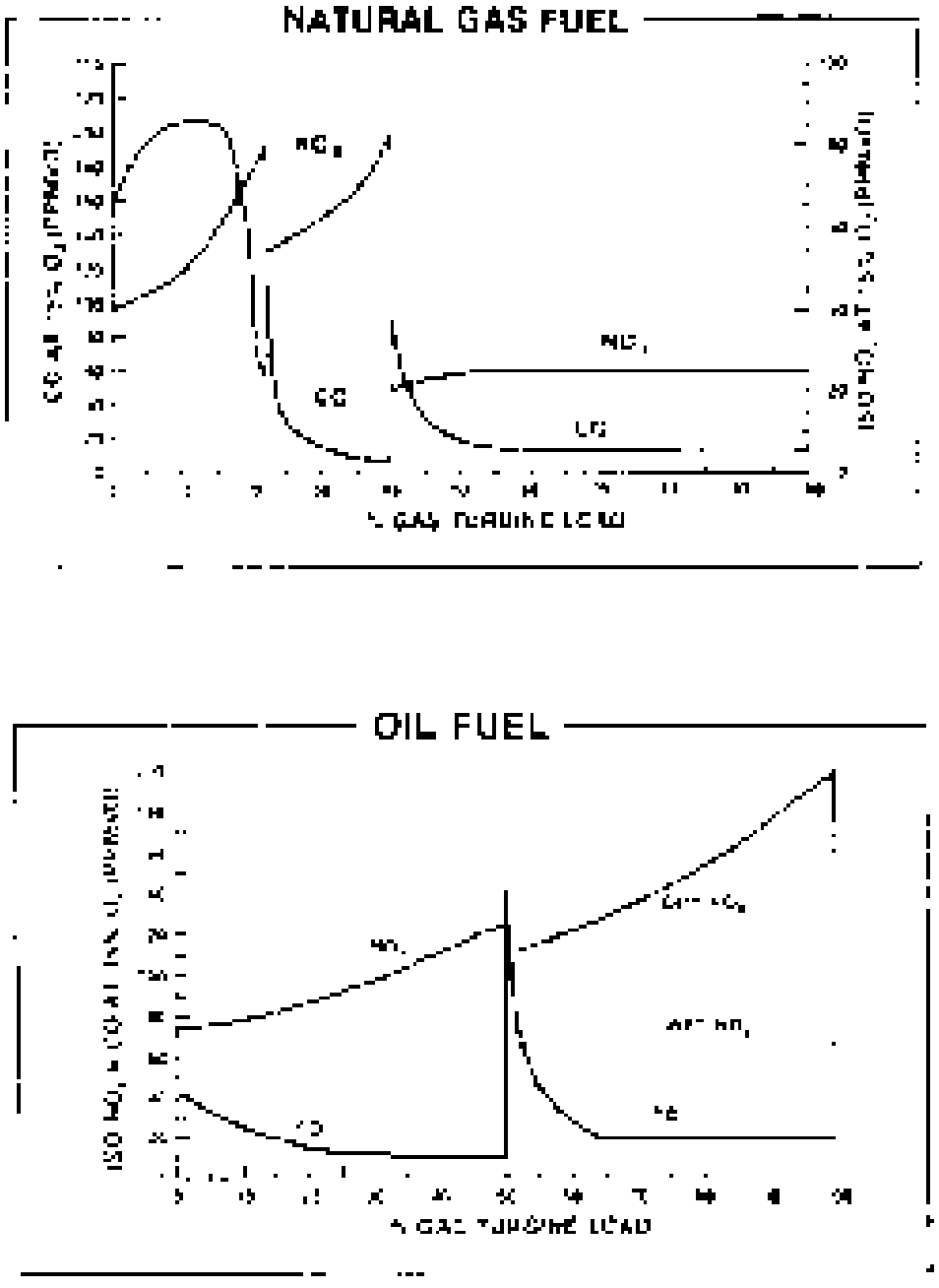


Figure 5-21. "Stepped" NO_x and CO emissions for a low-NO_x can-annular combustor burning natural gas and distillate oil fuels.[47]

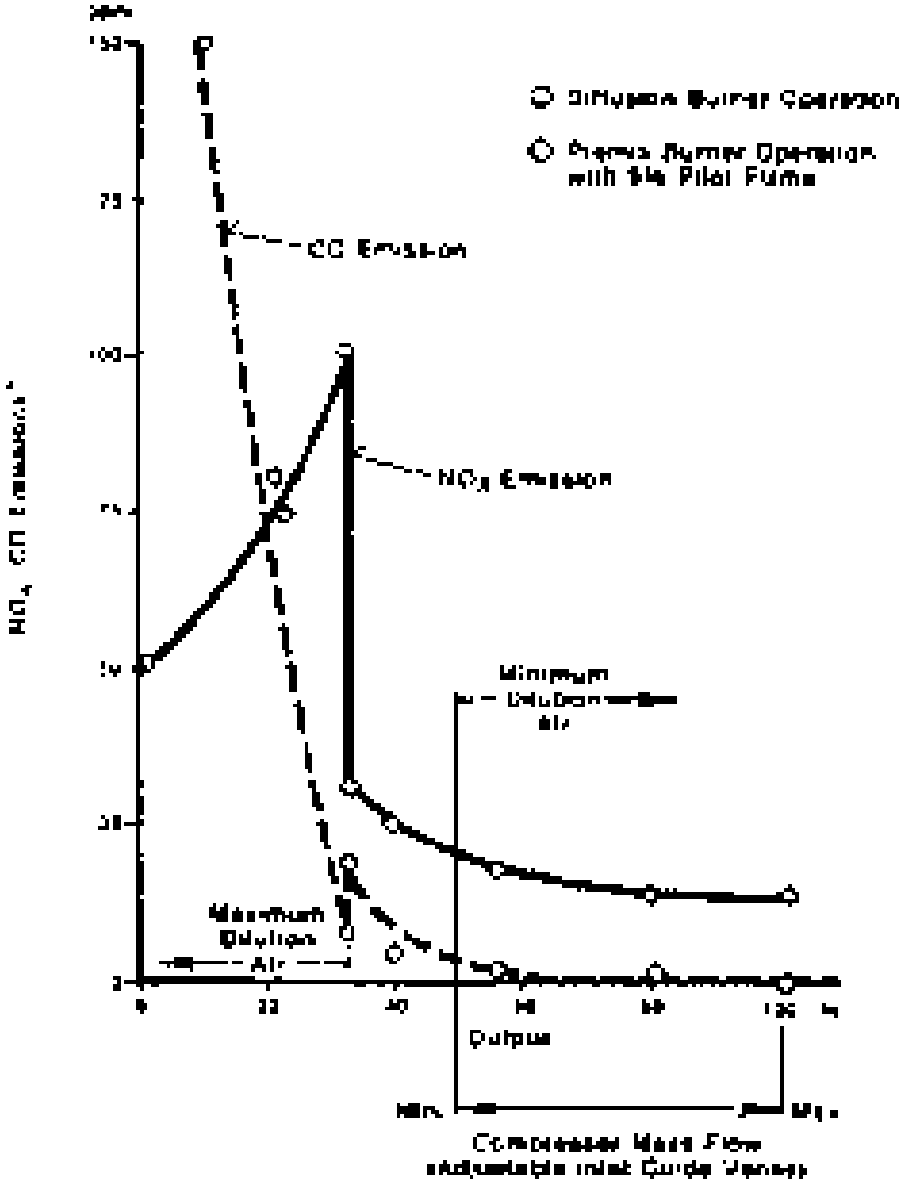


Figure 5-22. "Stepped" NO_x and CO emissions for a low-NO_x silo combustor burning natural gas.[35]

shows these stepped NO_x emissions levels for a can-annular combustor for natural gas and oil fuel operation. Figure 5-22

shows the emissions for a silo combustor operating on natural gas only.

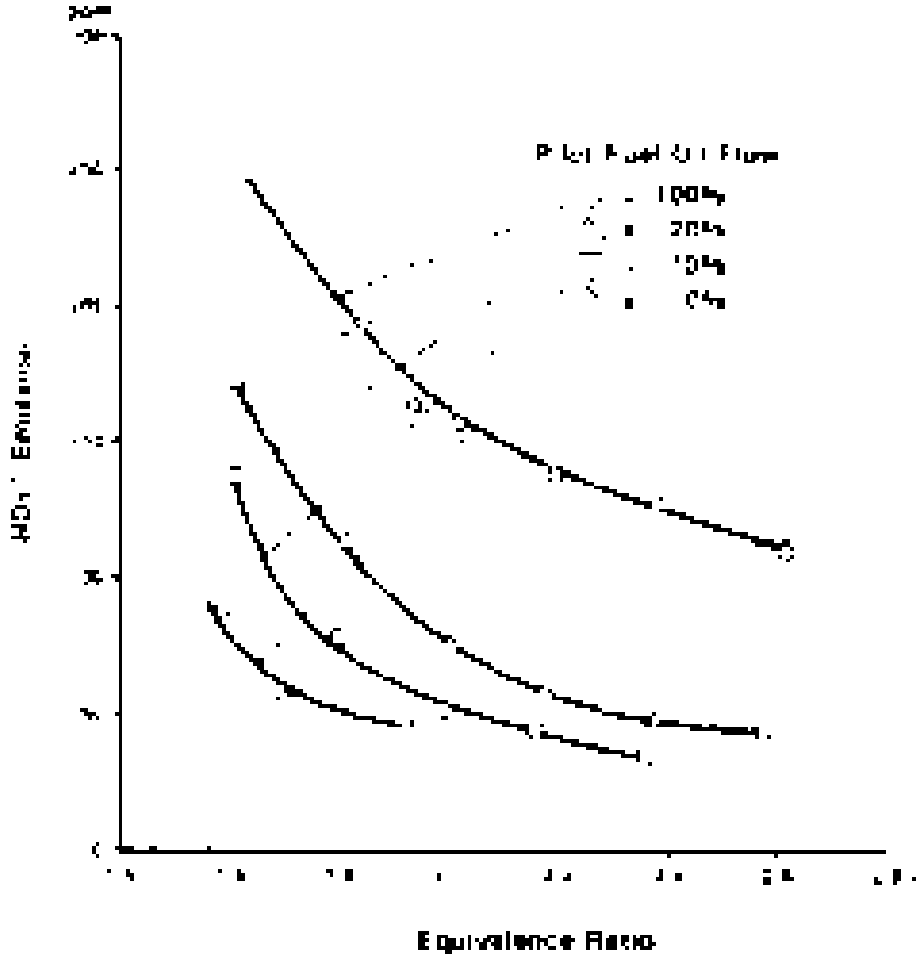


Figure 5-23. Nitrogen oxide emission text results from a lean premix silo combustor firing fuel oil without wet injection.[53]

The emission levels shown in Figures 5-21 and 5-22 correspond to full-scale production turbines currently available from the manufacturers.

Reduced NO_x emissions when burning oil fuel in currently available lean premixed combustor designs have been achieved only with water or steam injection. With water or steam injection, a 65 ppmv NO_x level can be achieved in the turbine with a can-annular combustor design; a 65 ppmv level can also be met with water injection in the turbine with a silo combustor at a WFR of 1.4.[48,52] This 65 ppmv level for lean premixed combustors is higher than the controlled NO_x levels achieved with water injection in oil-fired turbines using a conventional combustor design.

Modification of the existing burner design used in the silo combustor to allow premixing of the oil fuel with air prior to combustion is under development. Tests performed using a 12 MW (16,200 hp) turbine achieved NO_x emission levels below 50 ppmv without wet injection, corrected to 15 percent O_2, compared to uncontrolled levels of 150 ppmv or higher. The NO_x levels, without wet injection, as a function of equivalence ratio are shown in Figure 5-23. The design equivalence ratio at rated load is approximately 2.1. As shown in this figure, NO_x emissions below 50 ppmv were achieved at rated power output at pilot fuel flow levels of 10 percent of the total fuel input.[52]

Site test data for two turbines using silo-type lean premixed combustors, as reported by the manufacturer, are shown in Table 5-12. As this table shows, NO_x emission levels as low as 16.5 ppmv were recorded for using natural gas fuel without

TABLE 5-12. MEASURED NO_x EMISSIONS FOR COMPLIANCE TESTS OF A NATURAL GAS-FUELED LEAN PREMIXED COMBUSTOR WITHOUT WATER INJECTION[22]

Turbine No.	Output, percent of baseline	NO_x emission level, ppmv[a]
1	107	17.7
1	100	16.5
2	100	24.1
2	75	20.4
1	50	22.3
2	50	22.2

[a]In dry exhaust with 15 percent O_2, by volume.

water injection. Subsequent emission tests have achieved levels below 10 ppmv.[51] Corresponding data for operation on oil fuel using only the pilot (diffusion) stage for combustion, and with water injection, is shown in Table 5-13. Levels of NO_x emissions

TABLE 5-13. MEASURED NO_x EMISSIONS FOR OPERATION OF A LEAN PREMIXED COMBUSTOR DESIGN OPERATING IN DIFFUSION MODE ON OIL FUEL WITH WATER INJECTION[22]

Turbine No.	Output, percent of baseload	NO_x emission level, ppmv[a]
1	Peak	69.3
2	Peak	53.6
1	100	59.9
2	100	51.6
1	75	54.3
2	75	49.2
2	50	54.8

[a]In dry exhaust with 15 percent O_2, by volume.

at base load for No. 2 fuel oil are between 50 and 60 ppmv.

Based on information provided by turbine manufacturers, the potential NO_x reductions using currently available lean premixed

combustors are shown in Table 5-14. As this table indicates, NO_x emission reductions range from 14.7 tons/yr for a 1.1 MW (1,480 hp) turbine to 10,400 tons/yr

TABLE 5-14. POTENTIAL NO_x REDUCTIONS FOR GAS TURBINES USING LEAN PREMIXED COMBUSTORS

Turbine model	Power output, MW	NO_x emissions					
		Uncontrolled		Controlled		NO_x reduction	
		Gas fuel, ppmv	Oil fuel, ppvm	Gas fuel, ppmv	Oil fuel, ppmv	Gas fuel, tons/yr[a]	Oil fuel, tons/yr[a b]
Saturn[c]	1.1	99	150	42	NA[d]	14.7	NA[d]
Centaur T-4500[c]	3.3	130	179	42	NA[d]	59.5	NA[d]
Centaur "H"[c]	4.0	105	160	42	NA[d]	49.8	NA[d]
Taurus[c]	4.5	114	168	42	NA[d]	62.4	NA[d]
Mars T-12000[c]	8.8	178	267	42	NA[d]	212	NA[d]
Mars T-14000[c]	10.0	199	NA[d]	42	NA[d]	270	NA[d]
MS6001B	39.0	148	267	25/9[e]	65	829/937	1,139
MS7001E	84.7	154	228	25/9[e]	65	1,820/2,050	2,360
MS7001F	161	210	353	25	65	4,540	5,190
MS9001E	125	161	241	25/9[e]	65	2,740/3,060	3,490
MS9001F	229	210	353	25	65	6,500	7,250
GT10	22.6	150	200	25	42	476	620
GT11N	83.3	390	560	25/9[e]	42	5,070/5,290	7,360
V84.2	105	212	360	25/9[e]	NA[f]	3,030/3,290	NA[f]
V94.2	153	212	360	9[e]	NA[f]	4,410/4,780	NA[f]
V64.3	61.5	380	530	42	NA[d]	3,210	NA[d]
V84.3[c]	141	380	530	42	NA[d]	7,230	NA[d]
V94.3[e]	204	380	530	42	NA[d]	10,400	NA[d]

[a]Based on 8,000 hours operation per year.
[b]Requires water or steam injection.
[c]Scheduled availability is 1994 for natural gas fuel.
[d]NA = Data not available.
[e]Standard NO_x guarantee is 25 ppmv. Manufacturers offer guaranteed NO_x levels as low as 9 ppmv for these turbines.
[f]Scheduled availability 1993 for oil fuel without water injection. Reference 17.

for a 204 MW (274,000 hp) turbine for operation on natural gas without wet injection. Corresponding NO_x emission reductions for operation on oil fuel, with water injection, range from 620 tons/yr for a 22.6 MW (30,300 hp) turbine to 7,360 tons/yr for an 83.3 MW (112,000 hp) turbine.

Limited data from two manufacturers showing the impact of lean premixed combustor designs on CO emissions are shown in Table 5-15.

TABLE 5-15. COMPARISON OF NO_x AND CO EMISSIONS FOR STANDARD VERSUS LEAN PREMIXED COMBUSTORS FOR TWO MANUFACTURERS' TURBINES[46,54]

	Emissions, ppmv, referenced to 15 percent O_2[a]				
		Standard combustor		Lean premixed combustor	
GT Model	Power output, MW	NO_x	CO	NO_x	CO
Centaur H	4.0	105	15	25-42	50[b]
Mars T-14000	10.0	199	5.5	25-42	50[b]
MS6001B	39.0	148	10	9	25
MS7001E	84.7	154	10	9	25
MS9001E	125	161	10	9	25
MS7001F	161	210	25	25	15
MS9001F	229	210	25	25	15

[a]For operation at ISO conditions using natural gas fuel.

[b]Maximum design goal for CO emissions. Most in-house test configurations have achieved CO emission levels between 5 and 25 ppmv.

For natural gas-fueled turbines with rated outputs of 10 MW (13,400 hp) or less, controlled NO_x emission levels of 25 to 42 ppmv result in a rise in CO emission levels from 25 ppmv or less to as high as 50 ppmv.[43] For turbines above 10 MW (13,400 hp), controlled NO_x emission levels of 9 ppmv result in a rise in CO emissions from 10 to 25 ppmv for natural gas fuel. Conversely, for controlled NO_x emission levels of 25 ppmv, the CO emissions drop from 25 to 15 ppmv.[51] For one manufacturer's lean premixed silo combustor design, CO emissions at rated load are less than 5 ppmv, as shown previously in Figure 5-21. This limited data suggest that the effect of lean premixed combustors on CO emissions depends upon the specific combustor design and the controlled NO_x emission level.

The emission levels shown in Table 5-15 correspond to rated power output. Like NO_x emission levels, CO emissions change with changes in combustor operating mode at reduced power output. The "stepped" effect on CO emissions is shown in Figures 5-21 and 5-22, shown previously.

Operation on oil fuel with wet injection, shown previously in Figure 5-21, shows CO emission levels of 20 ppmv. Additional CO emission data were not available for operation on oil fuel with water injection in lean premixed combustors. Developmental tests for operation on oil fuel without wet injection in a silo combustor are presented in Figure 5-24

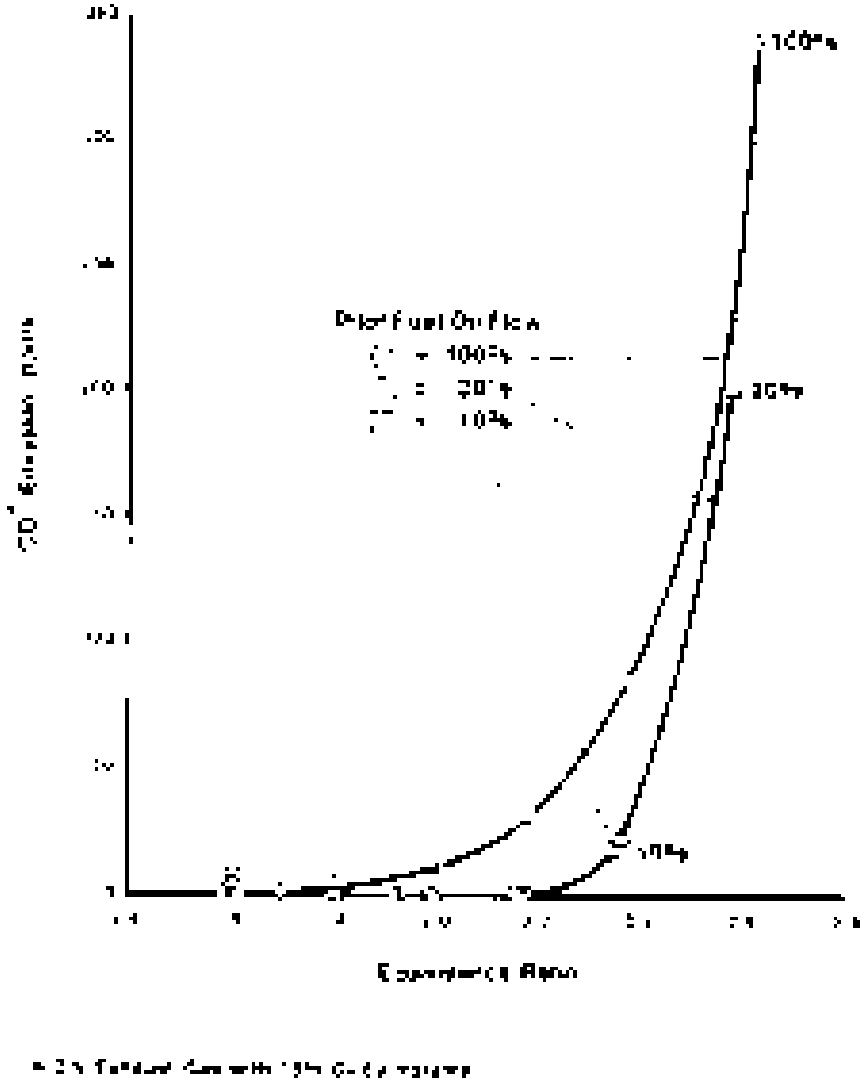


Figure 5-24. The CO emission test results from a lean premix silo combustor firing fuel oil without wet injection.

. At rated load, shown in this figure at an equivalence ratio of approximately 2.1, CO emissions are less than 10 ppmv, corrected to 15 percent $O_{2,}$

and are in the range of 0 to 2 ppmv for a pilot oil fuel flow of 10 percent (representing 10 percent of the total fuel flow).[53] This 10 percent pilot fuel flow corresponds to controlled NO_x emission levels below 50 ppmv, as shown previously in Figure 5-22. No data for HC emissions were available for lean premixed burner designs.

5.2.3 Rich/Quench/Lean Combustion

5.2.3.1 Process Description. Rich/quench/lean (RQL) combustors burn fuel-rich in the primary zone and fuel-lean in the secondary zone. Incomplete combustion under fuel-rich conditions in the primary zone produces an atmosphere with a high concentration of CO and hydrogen (H_2). The CO and H_2 replace some of the oxygen normally available for NO_x formation and also act as reducing agents for any NO_x formed in the primary zone. Thus, fuel nitrogen is released with minimal conversion to NO_x. The lower peak flame temperatures due to partial combustion also reduce the formation of thermal NO_x.[55]

As the combustion products leave the primary zone, they pass through a low-residence-time quench zone where the combustion products are rapidly diluted with additional combustion air or water. This rapid dilution cools the combustion products and at the same time produces a lean A/F. Combustion is then completed under fuel-lean conditions. This secondary lean combustion step minimally contributes to the formation of fuel NO_x because most of the fuel nitrogen will have been converted to N_2 prior to the lean combustion phase. Thermal NO_x is minimized during lean combustion due to the low flame temperature.[55]

5.2.3.2 Applicability. The RQL combustion concept applies to all types of gas turbines. None of the manufacturers contacted for this study, however, currently have this design available for their production turbines. This may be due to lack of demand for this design due to the current limited use of high-nitrogen-content fuels in gas turbines.

5.2.3.3 Factors Affecting Performance. The NO_x emissions from RQL combustors are affected primarily by the equivalence ratio in the primary combustion zone and the quench airflow rate.

Careful selection of equivalence ratios in the fuel-rich zone will minimize both thermal and fuel NO_x formation. Further NO_x reduction is achieved with increasing quench airflow rates, which serve to reduce the equivalence ratio in the secondary (lean) combustion stage.

5.2.3.4 Achievable NO_x Emissions Levels Using Rich/Quench/Lean Combustion. The RQL staged combustion has been demonstrated in rig tests to be effective in reducing both thermal NO_x and fuel NO_x. As shown in Figure 5-25, NO_x emissions are reduced by 40 to 50 percent in a test rig burning diesel fuel.

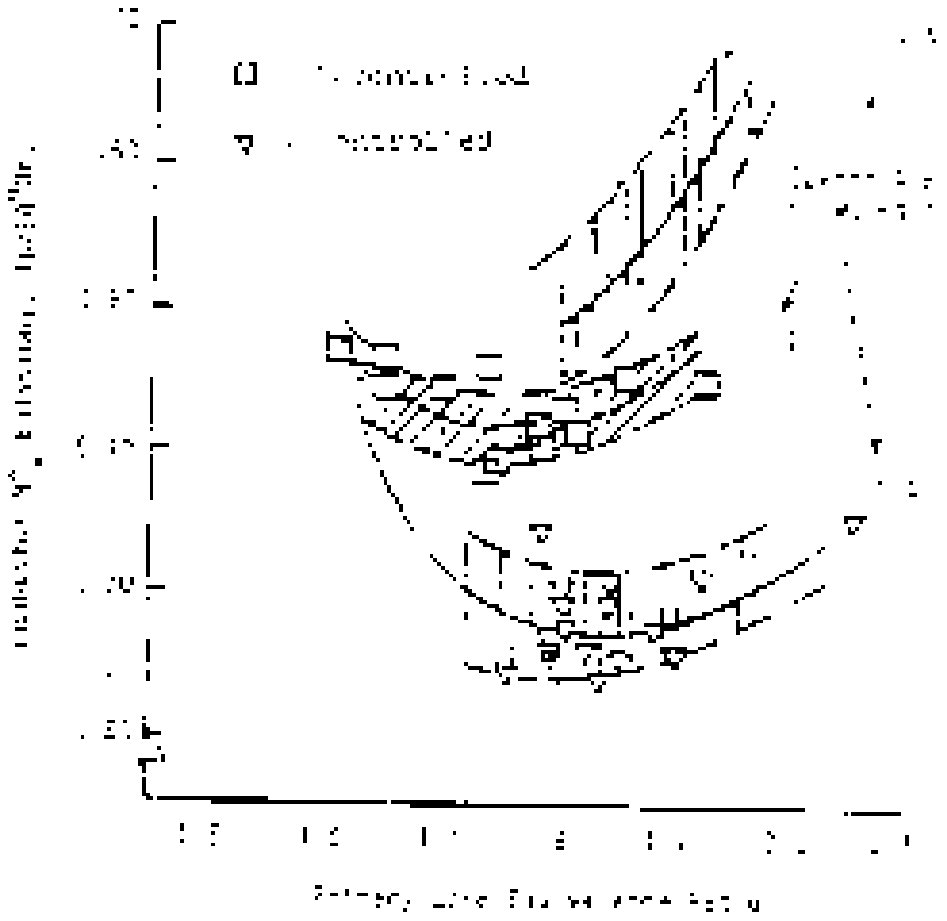


Figure 5-25. Nitrogen oxide emissions versus primary zone equivalence ratio for a rich/quench/lean combustor firing distillate oil.[56]

At an equivalence ratio of 1.8, the NO_x emissions can be reduced from 0.50 to 0.27 lb/MMBtu by increasing the quench airflow from 0.86 to 1.4 kg/sec. Data were not available to convert the NO_x emissions figures to ppmv. The effectiveness of rich/lean staged combustion in reducing fuel NO_x when firing high-FBN fuels is shown in Figure 5-26.

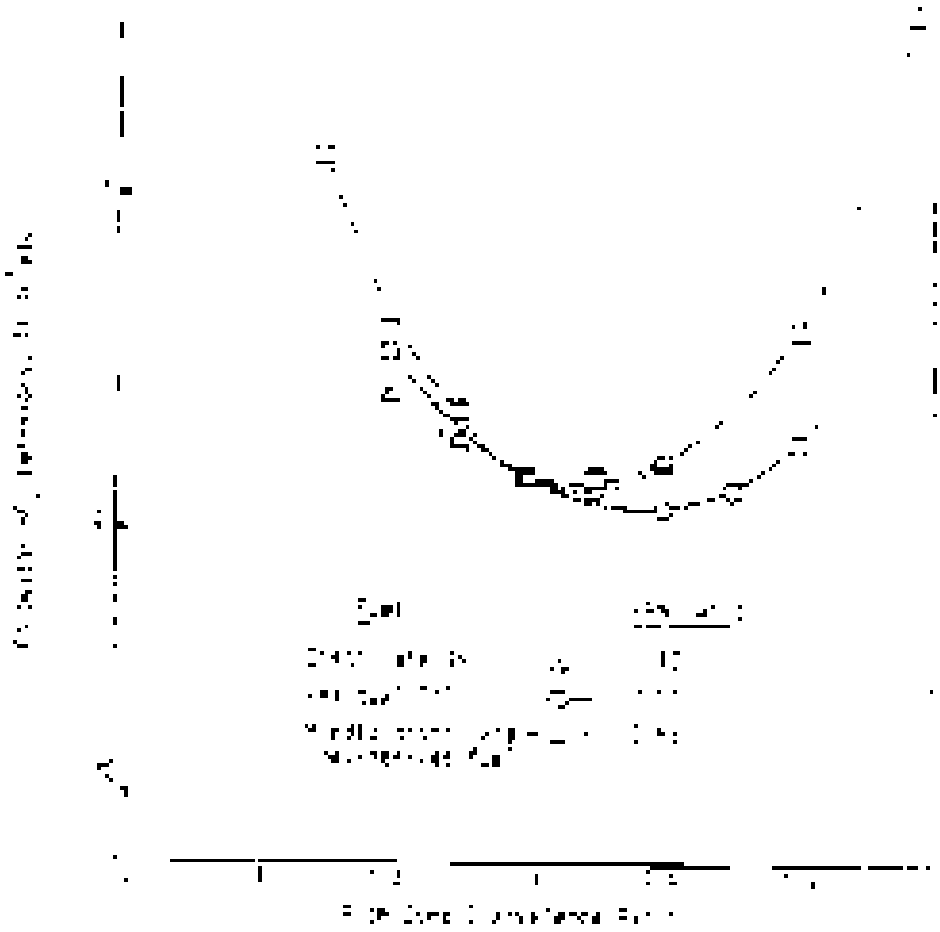


Figure 5-26. Effects of fuel bound nitrogen (FBN) content of NO_x emissions for a rich/quench/lean combustor.[57]

Increasing the FBN content from 0.13 to 0.88 percent has little impact on the total NO_x formation at an operating equivalence ratio of 1.3 to 1.4. Tests on other rich/lean combustors indicate fuel nitrogen conversions to NO_x of about 7 to 20 percent.[58,59] These fuel nitrogen conversions represent a fuel NO_x emission reduction of approximately 50 to 80 percent.

One manufacturer has tested an RQL combustor design in a 4 MW (5,360 hp) gas turbine fueled with a finely ground coal and water mixture. The coal partially combusts in a fuel-rich zone at temperatures of 1650°C (3000°F), with low O_2 levels and an extremely short residence time. The partially combusted products are then rapidly quenched with water, cooling combustion temperatures to inhibit thermal NO_x formation. Additional combustion air is then introduced, and combustion is completed under fuel-lean conditions. In tests at the manufacturer's plant, cosponsored by the U. S. Department of Energy, a NO_x emission level of 25 ppmv at 15 percent O_2 was achieved. This combustor design can also be used with natural gas and oil fuels. Single-digit NO_x emission levels are reported for operation on

natural gas fuel. This combustor design is not yet available for production turbines.[60]

5.3 SELECTIVE CATALYTIC REDUCTION

Selective catalytic reduction (SCR) is an add-on NO_x control technique that is placed in the exhaust stream following the gas turbine. Over 100 gas turbine installations use SCR in the United States.[61] An SCR process description, the applicability of SCR for gas turbines, the factors affecting SCR performance, and the achievable NO_x reduction efficiencies are discussed in this section.

5.3.1 Process Description

The SCR process reduces NO_x emissions by injecting ammonia into the flue gas. The ammonia reacts with NO_x in the presence of a catalyst to form water and nitrogen. In the catalyst unit, the ammonia reacts with NO_x primarily by the following equations:[62]

$$NH_3 + NO + 1/4\ O_2 \rightarrow N_2 + 3/2\ H_2O;\ \text{and}$$

$$NH_3 + 1/2\ NO_2 + 1/4\ O_2 \rightarrow 3/2\ N_2 + 3/2\ H_2O.$$

The catalyst's active surface is usually either a noble metal, base metal (titanium or vanadium) oxide, or a zeolite-based material. Metal-based catalysts are usually applied as a coating over a metal or ceramic substrate. Zeolite catalysts are typically a homogenous material that forms both the active surface and the substrate. The geometric configuration of the catalyst body is designed for maximum surface area and minimum obstruction of the flue gas flow path to maximize conversion efficiency and minimize back-pressure on the gas turbine. The most common catalyst body configuration is a monolith, "honeycomb" design, as shown in Figure 5-27.

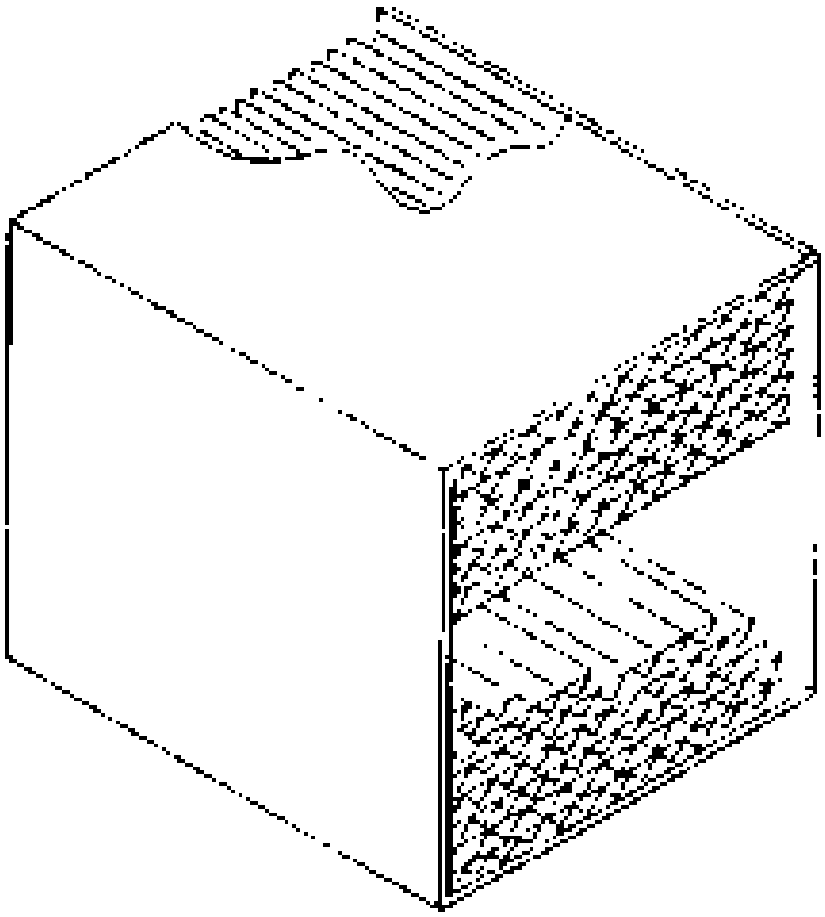


Figure 5-27. Cutaway view of a typical monolith catalyst body with honeycomb configuration.[62]

An ammonia injection grid is located upstream of the catalyst body and is designed to disperse the ammonia uniformly throughout the exhaust flow before it enters the catalyst unit. In a typical ammonia injection system, anhydrous ammonia is drawn from a storage tank and evaporated using a steam- or electric-heated vaporizer. The vapor is mixed with a pressurized carrier gas to provide both sufficient momentum through the

injection nozzles and effective mixing of the ammonia with the flue gases. The carrier gas is usually compressed air or steam, and the ammonia concentration in the carrier gas is about 5 percent.[62]

An alternative to using the anhydrous ammonia/carrier gas system is to inject an a aqueous ammonia solution. This system is currently not as common but removes the potential safety hazards associated with transporting and storing anhydrous ammonia and is often used in installations with close proximity to populated areas.[61,62]

The NH_3/NO_x ratio can be varied to achieve the desired level of NO_x reduction. As indicated by the chemical reaction equations listed above, it takes one mole of NH_3 to reduce one mole of NO, and two moles of NH_3 to reduce one mole of NO_2. The NO_x composition in the flue gas from a gas turbine is over 85 percent NO, and SCR systems generally operate with a molar NH_3/NO_x ratio of approximately 1.0.[63] Increasing this ratio will further reduce NO_x emissions but will also result in increased unreacted ammonia passing through the catalyst and into the atmosphere. This unreacted ammonia is known as ammonia slip.

5.3.2 Applicability of SCR for Gas Turbines

Selective catalytic reduction applies to all gas turbine types and is equally effective in reducing both thermal and fuel NO_x emissions. There are, however, factors that may limit the applicability of SCR.

An important factor that affects the performance of SCR is operating temperature. Gas turbines that operate in simple cycle have exhaust gas temperatures ranging from approximately 450° to 540°C (850° to 1000°F). Base-metal catalysts have an operating temperature window for clean fuel applications of approximately 260° to 400°C (400° to 800°F). For sulfur-bearing fuels that produce greater than 1 ppm SO_3 in the flue gas, the catalyst operating temperature range narrows to 315° to 400°C (600° to 800°F). The upper range of this temperature window can be

increased using a zeolite catalyst to a maximum of 590°C (1100°F).[64]

Base metal catalysts are most commonly used in gas turbine SCR applications, accounting for approximately 80 percent of all U.S. installations, and operate in cogeneration or combined cycle applications. The catalyst is installed within the HRSG, where the heat recovery process reduces exhaust gas temperatures to the proper operating range for the catalyst. The specific location of the SCR within the HRSG is application-specific; Figure 5-28 shows two possible SCR locations.

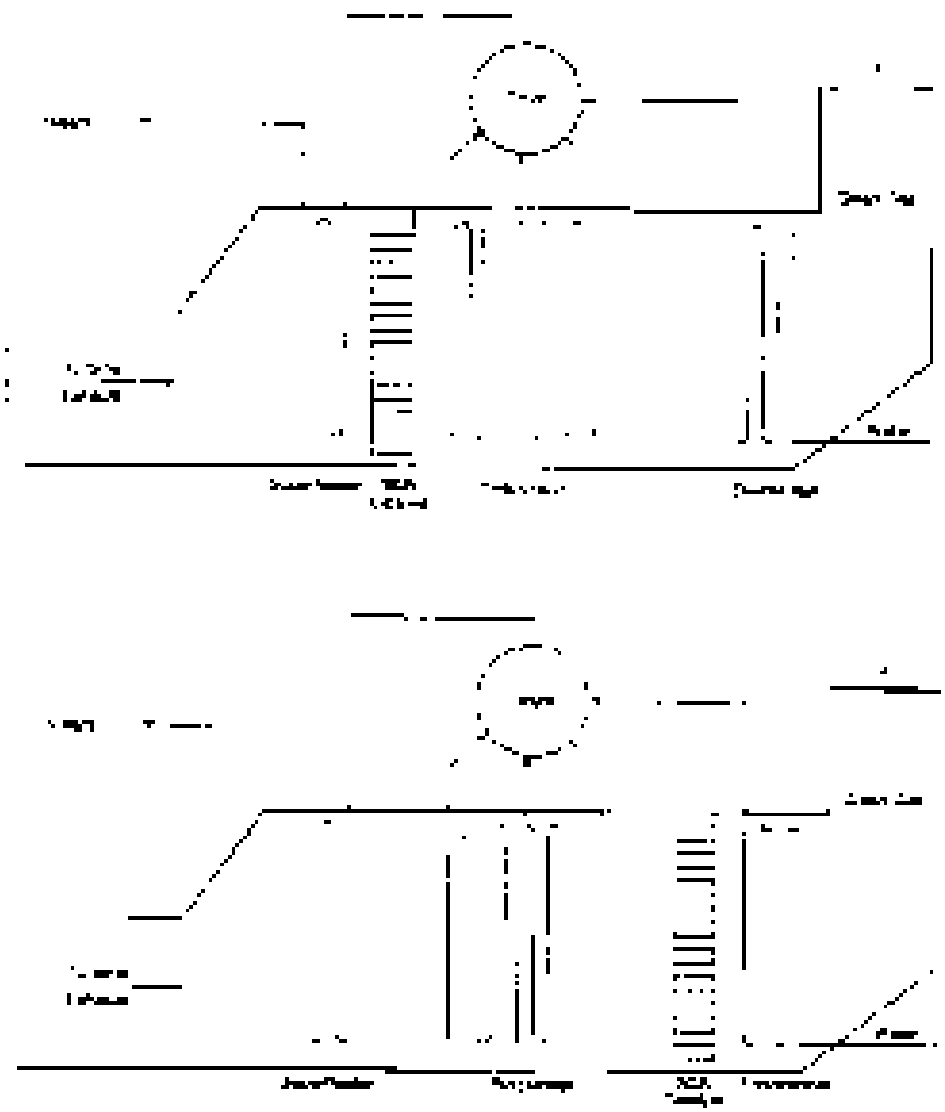


Figure 5-28. Possible locations for SCR unit in HRSG.[62]

In addition to the locations shown, the catalyst may also be located within the evaporator section of the HRSG.

As noted above, zeolite catalysts have a maximum operating temperature range of up to 590°C (1100°F), which is compatible with simple cycle turbine exhaust temperatures. To date, however, there is only one SCR installation operating with a zeolite catalyst directly downstream of the turbine. This catalyst, commissioned in December 1989, has an operating range of 260° to 515°C (500° to 960°F) and operates approximately 90 percent of the time at temperatures above 500°C (930°F).[65]

Another consideration in determining the applicability of SCR is complications arising from sulfur-bearing fuels. The sulfur content in pipeline quality natural gas is negligible, but distillate and residual oils as well as some low-Btu fuel gases such as coal gas have sulfur contents that present problems when used with SCR systems. Combustion of sulfur-bearing fuels produces SO_2 and SO_3 emissions. A portion of the SO_2 oxidizes to SO_3 as it passes through the HRSG, and base metal catalysts have an SO_2-to-SO_3 oxidation rate of up to five percent.[64] In addition, oxidation catalysts, when used to reduce CO emissions, will also oxidize SO_2 to SO_3 at rates of up to 50 percent.[66]

Unreacted ammonia passing through the catalyst reacts with SO_3 to form ammonium bisulfate (NH_4HSO_4) and ammonium sulfate [$(NH_4)_2\ SO_4$] in the low-temperature section of the HRSG. The rate of ammonium salt formation increases with increasing levels of SO_3 and NH_3, and the formation rate increases with decreasing

temperature. Below 200°C (400°F), ammonium salt formation occurs with single-digit ppmv levels of SO_3 and NH_3.[66]

The exhaust temperature exiting the HRSG is typically in the range of 150° to 175°C (300° to 350°F), so ammonium salt formation typically occurs in the low-temperature section of the HRSG.[66] Ammonium bisulfate is a sticky substance that over time corrodes the HRSG boiler tubes. Additionally, it deposits on both the boiler and catalyst bed surfaces, leading to fouling and plugging of these surfaces. These deposits result in increased back pressure on the turbine and reduced heat transfer efficiency in the HRSG. This requires that the HRSG be removed from service periodically to water-wash the affected surfaces. Ammonium sulfate is not corrosive, but like ammonium bisulfate, it deposits on the HRSG surfaces and contributes to plugging and fouling of the heat transfer system.[33]

Formation of ammonium salts can be avoided by limiting the sulfur content of the fuel and/or limiting the ammonia slip. Low SO_2-to-SO_3 oxidizing catalysts are also available. Base metal catalysts are available with oxidation rates of less than 1 percent, but these low oxidation formulas also have lower NO_x reduction activity per unit volume and therefore require a greater catalyst volume to achieve a given NO_x reduction level. Zeolite catalysts are reported to have intrinsic SO_2-to-SO_3 oxidation rates of less than 1 percent.[64,66] As stated above, pipeline-quality natural gas has negligible sulfur content, but some sources of natural gas contain H_2S, which may contribute to ammonium salt formation. For oil fuels, even the lowest-sulfur distillate oil or liquid aviation fuel contains sulfur levels that can produce ammonium salts. According to catalyst vendors, SCR systems can be designed for 90 percent NO_x reduction and 10 ppm or lower NH_3 slip for sulfur-bearing fuels up to 0.3 percent by weight.[64] Continuous emission monitoring equipment has been developed for NH_3, and may be instrumental in regulating ammonia injection to minimize slip.[67]

To date, there is limited operating experience using SCR with oil-fired gas turbine installations. One combined cycle

installation using oil fuel, a United Airlines facility in San Francisco installed in 1985, experienced fuel-related catalyst problems and now uses only natural gas fuel.[33] In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now available, however, and catalyst formulation improvements have proven effective in resisting performance degradation with oil fuels in Europe and Japan, where catalyst life in excess of 4 to 6 years has been achieved, versus 8 to 10 years with natural gas fuel.[64] A zeolite catalyst installed on a 5 MW (6710 hp) dual fuel reciprocating engine in the northeastern United States has operated for over 3 years and burned approximately 600,000 gallons of diesel fuel while maintaining a NO_x reduction efficiency of greater than 90 percent.[3]

In its guidance to member states, NESCAUM recommends that SCR be considered for NO_x reduction in dual-fueled turbine applications. There are four combined cycle gas turbines installations operating with SCR in the northeast United States burning natural gas as the primary fuel with oil fuel as a back-up.[3] These installations, listed in Table 5-16,

TABLE 5-16. GAS TURBINE INSTALLATIONS IN THE NORTHEASTERN UNITED STATES WITH SCR AND PERMITTED FOR BOTH NATURAL GAS AND OIL FUELS[3]

Installation	State	Gas turbine model	Output, MW[a]	NO_x emissions, ppmv (gas fuel/oil fuel)		
				Uncontrolled[b]	Wet injection[b]	Wet injection + SCR[c]
Altresco-Pittsfield	MA	MS6001	38.3	148/267	42/65	9/18[d e]
Cogen Technologies	NJ	MS6001	38.3	148/267	42/65	15/65[f]
Ocean State Power	RI	MS7001E	83.5	154/277	42/65	9/42[f]
Pawtucket Power	RI	MS6001	38.3	148/267	42/65	9/18[d]

[a]Power output for a single gas turbine. Installation power output is higher due to multiple units and/or combined cycle operation.

[b]Per manufacturer at ISO conditions.

[c]Operating permit limits.

[d]This installation requires the SCR system to be operational when burning oil fuel.

[e]This installation operated 185 hours on oil fuel in 1991, burning approximately 354,000 gallons of oil fuel.

[f]Ammonia injection is shut down during operation on oil fuel.

began operating recently and have limited hours of operation on oil fuel. As indicated in the table, two of these installations shut down the ammonia injection when operating on oil fuel to prevent potential operating problems arising from sulfur-bearing fuels. Permits issued more recently in this region for other dual-fuel installations, however, require that the SCR system be operational on either fuel.[3]

A final consideration for SCR is catalyst masking or poisoning agents. Natural gas is considered clean and free of contaminants, but other fuels may contain agents that can degrade catalyst performance. For refinery, field, or digester gas fuel applications, it is important to have an analysis of the fuel and properly design the catalyst for any identified contaminants. Arsenic, iron, and silica may be present in field gases, along with zinc and phosphorus. Catalyst life with these fuels depends upon the content of the gas and is a function of the initial

design parameters. With oil fuels, in addition to the potential for ammonium salt formation, it is important to be aware of heavy metal content. Particulates in the flue gas can also mask the catalyst.[64]

Selective catalytic reduction may not be readily applicable to gas turbines firing fuels that produce high ash loadings or high levels of contaminants because these elements can lead to fouling and poisoning of the catalyst bed. However, because gas turbines are also subject to damage from these elements, fuels with high levels of ash or contaminants typically are not used.

Coal, while not currently a common fuel for turbines, has a number of potential catalyst deactivators. High dust concentrations, alkali, earth metals, alkaline heavy metals, calcium sulfate, and chlorides all can produce a masking or blinding effect on the catalyst. High dust can also erode the catalyst. Erosion commonly occurs only on the leading face of the catalyst. Airflow deflectors and dummy layers of catalyst can be used to straighten out the airflow and reduce erosion. There is currently no commercial U.S. experience with coal. In Japan, which burns low-sulfur coal with moderate dust levels, catalyst life has been 5 years or more without replacement. In Germany, with high dust loadings, the experience has also been 5 years or more.[64]

Masking agents deposit on the surface of the catalyst, forming a barrier between the active catalyst surface and the exhaust gas, inhibiting catalytic activity. Poisoning agents chemically react with the catalyst and render the affected area inactive. Masking agents can be removed by vacuuming or by using soot blowers or superheated steam. Catalysts cleaned in this manner can recover greater than 90 percent of the original reduction activity. The effects of poisoning agents, however, are permanent and the affected catalyst surface cannot be regenerated.[64]

Retrofit applications for SCR may require the addition of a heat exchanger for simple cycle installations, and replacement or extensive modification of the existing HRSG in cogeneration and

combined cycle applications to accommodate the catalyst body. For these reasons, retrofit applications for SCR could involve high capital costs.

5.3.3 Factors Affecting SCR Performance

The NO_x reduction efficiency for an SCR system is influenced by catalyst material and condition, reactor temperature, space velocity, and the NH_3/NO_x ratio.[63] These design and operating variables are discussed below.

Several catalyst materials are available, and each has an optimum NO_x removal efficiency range corresponding to a specific temperature range. Proprietary formulations containing titanium dioxide, vanadium pentoxide, platinum, or zeolite are available to meet a wide spectrum of operating temperatures. The NO_x removal efficiencies for these catalysts are typically between 80 and 90 percent when new. The NO_x removal efficiency gradually decreases over the operating life of the catalyst due to deterioration from masking, poisoning, or sintering.[63] The rate of catalyst performance degradation depends upon operating conditions and is therefore site-specific.

The space velocity (volumetric flue gas flow divided by the catalyst volume) is an indicator of gas residence time in the catalyst unit. The lower the space velocity, the higher the residence time, and the higher the potential for increased NO_x reduction. Because the gas flow is a constant determined by the gas turbine, the space velocity depends upon the catalyst volume, or total active surface area. The distance across the opening between plates or cells in the catalyst, referred to as the pitch, affects the overall size of the catalyst body. The smaller the pitch, the greater the number of rows or cells that can be placed in a given volume. Therefore, for a given catalyst body size, the smaller the pitch, the larger the catalyst volume and the lower the space velocity. For natural gas applications the catalyst pitch is typically 2.5 millimeters (mm) (0.10 inch [in.]), increasing to 5 to 7 mm (0.20 to 0.28 in.) for coal-fuel applications.[64]

As discussed in Section 5.3.1, the NH_3/NO_x ratio can be varied to achieve the desired level of NO_x reduction. Increasing this ratio increases the level of NO_x reduction but may also result in higher ammonia slip levels.

5.3.4 Achievable NO_x Emission Reduction Efficiency Using SCR

Most SCR systems operating in the United States have a space velocity of about 30,000/hr, a NH_3/NO_x ratio of about 1.0, and ammonia slip levels of approximately 10 ppm. The resulting NO_x reduction efficiency is about 90 percent.[41] Reduction efficiency is the level of NO_x removed as a percentage of the level of NO_x entering the SCR unit. Only one gas turbine installation in the United States was identified using only SCR to reduce NO_x emissions. This installation has two natural gas-fired 8.5 MW gas turbines, each with its own HRSG in which is installed an SCR system. A summary of emission testing at this site lists NO_x emissions at the inlet to the SCR catalyst at 130 ppmv. Controlled NO_x emissions downstream of the catalyst were 18 ppmv, indicating a NO_x reduction efficiency of 86 percent. Maximum ammonia slip levels were listed at 35 ppmv.[68]

All other gas turbine installations identified as using SCR in the United States use this control method in combination with wet injection and/or low-NO_x combustors. The emission levels that can be achieved by this combination of controls are found in Section 5.4.

5.3.5 Disposal Considerations for SCR

The SCR catalyst material has a finite life, and disposal can pose a problem. The guaranteed catalyst life offered by catalyst suppliers ranges from 2 to 3 years.[64] In Japan, where SCR systems have been in operation since 1980, experience shows that many catalysts in operation with natural gas-fired boilers have performed well for 7 years or longer.[63,64] In any case, at some point the catalyst must be replaced, and those units containing heavy metal oxides such as vanadium or titanium potentially could be considered hazardous wastes. While the amount of hazardous material in the catalyst is relatively small, the volume of the catalyst body can be quite large, and disposal

of this waste could be costly. Some suppliers provide for the removal and disposal of spent catalyst. Precious metal and zeolite catalysts do not contain hazardous wastes.

5.4 CONTROLS USED IN COMBINATION WITH SCR

With but one exception, SCR units installed in the United States are used in combination with wet controls or combustion controls described in Sections 5.1 and 5.2. Wet controls yield NO_x emission levels of 25 to 42 ppmv for natural gas and 42 to 110 ppmv for distillate oil, based on the data provided by gas turbine manufacturers and shown in Figures 5-10 and 5-11. A carefully designed SCR system can achieve NO_x reduction efficiencies as high as 90 percent, with ammonia slip levels of 10 ppmv or less for natural gas and low-sulfur (<0.3 percent by weight) fuel applications.[64]

As discussed for wet injection in Sections 5.1.4 and 5.2.2.4, controlled NO_x emission levels for natural gas range from 25 to 42 ppmv for natural gas fuel and from 42 to 110 ppmv for oil fuel. Applying a 90 percent reduction efficiency for SCR, NO_x levels can be theoretically reduced to 2.5 to 4.2 and 4.2 to 11.0 ppmv for natural gas and oil fuels, respectively. For oil fuels and other sulfur-bearing fuels, a reduction efficiency of 90 percent requires special design considerations to address potential operational problems caused by the sulfur content in the fuel. This subject is discussed in Section 5.3.2. The final controlled NO_x emission level depends upon the NO_x level exiting the turbine and the achievable SCR reduction efficiency.

Test reports provided by SCAQMD include three gas turbine combined cycle installations fired with natural gas that have achieved NO_x emission levels of 3.4 to 7.2 ppmv, referenced to 15 percent oxygen. The NO_x and CO emissions reported for these tests are shown in Table 5-17

TABLE 5-17. EMISSIONS TESTS RESULTS FOR GAS TURBINES USING STEAM INJECTION PLUS SCR[69-71]

				NO_x emissions, ppmv (lb/hr)			
Test No.	Gas turbine model	Output, MW	Fuel	Uncontrolled	Wet injection	Wet injection + SCR	CO, ppmv
1	MS7001E	82.8	Natural gas + refinery gas mixture	154	42	5.66 (25.2)	<2.00
2	MS7001E	79.7	Natural gas + refinery gas + butane mixture	148	42	7.17 (31.7)	<2.00
3	MS6001B	33.8	LPG + refinery gas mixture	148	42	3.36 (5.82)	<2.00

TABLE 5-18. SUMMARY OF SCR NO_x EMISSION REDUCTIONS AND AMMONIA SLIP LEVELS FOR NATURAL GAS-FIRED TURBINES[68]

Site	Gas turbine		Power output, MW	SCR operating temperature, °F	Maximum permit level for injection, NH_3/NO_x molar ratio	NO_x emissions, ppmv at 15% O_2			Compliance test NH_3 slip, ppmv at 15% O_2 [a]
	Manufacturer	Model				SCR in	SCR out	Percent reduction	
A	GE	LM2500	22	730	1.0	50	9.0	82	10
B	GE	MS5001	18	645	1.0	45	4.5	90	2
C	GE	LM2500	22	685	1.1	37	8.9	76	20
D	ABB	Type 8	44	760	1.2	27	4	85	9
E	GE	LM2500	22	680	1.0	60	12.6	79	7
F	GE	MS7001E	80	630	1.0	28	8.4	70	4.1
G	GE	LM2500	22	625	0.9	68	13.6	80	1
H	Allison	501-KB	3.5	650	1.1	25	1.0	96	10
I	Solar	Mars	8.5	580	1.6	130	18.2	86	35
J	GE	LM2500	22	750	1.0	37	14.8	60	11
K	GE	MS7001E	80	754	1.0	40	6.0	85	2
L	GE	MS6001	37	650	1.0	47	8.9	81	4
M	GE	MS6001	37	700	NA	33	3.3	90	8

[a]Calculated from ppmv entering the SCR and percent reduction figures.
[b]NH_3 permit limit. Test emission level not available.
[c]Test was run at less than permit NH_3/NO_x ratio of 1.1. SCR designed for exhaust from total of 5 turbines. Only one turbine operating during test.
[d]This site does not use wet injection for gas turbine NO_x reduction.
[e]NH_3 compliance test not required. NH_3 level from NH_3 monitor testing.

Ammonia slip levels were not reported. Ammonia slip levels

were reported, however, in a summary of emission tests for 13 SCR installations and are presented in Table 5-18.[68] For these sites, operating on natural gas fuel, the NO_x reduction efficiency of the catalyst ranges

from 60 to 96 percent, with most reduction efficiencies between 80 and 90 percent. Ammonia slip levels range from 1 to 35 ppmv. The site with the 35 ppmv ammonia slip level is unique in that it is the only site identified in the United States that uses only SCR rather than a combination of SCR and wet injection to reduce NO_x emissions. With the exception of this site, all NH_3 slip levels in Table 5-18 that are based on test data are less than 10 ppmv. Based on information received from catalyst vendors, it is expected that an SCR system operating downstream of a gas turbine without wet injection could be designed to limit ammonia slip levels to 10 ppmv or less.[64] No test data are available for SCR operation on gas turbines fired with distillate oil fuels.

5.5 EFFECT OF ADDING A DUCT BURNER IN HRSG APPLICATIONS

A duct burner is often added in cogeneration and combined cycle applications to increase the steam capacity of the HRSG (see Section 4.2.2). Duct burners in gas turbine exhaust streams consist of pipes or small burners that are placed in the exhaust gas stream to allow firing of additional fuel, usually natural gas. Duct burners can raise gas turbine exhaust temperatures to 1000°C (2000°F), but a more common temperature is 760°C (1400°F). The gas turbine exhaust is the source of oxygen for the duct burner.

Figure 5-29 shows a typical natural gas-fired duct burner

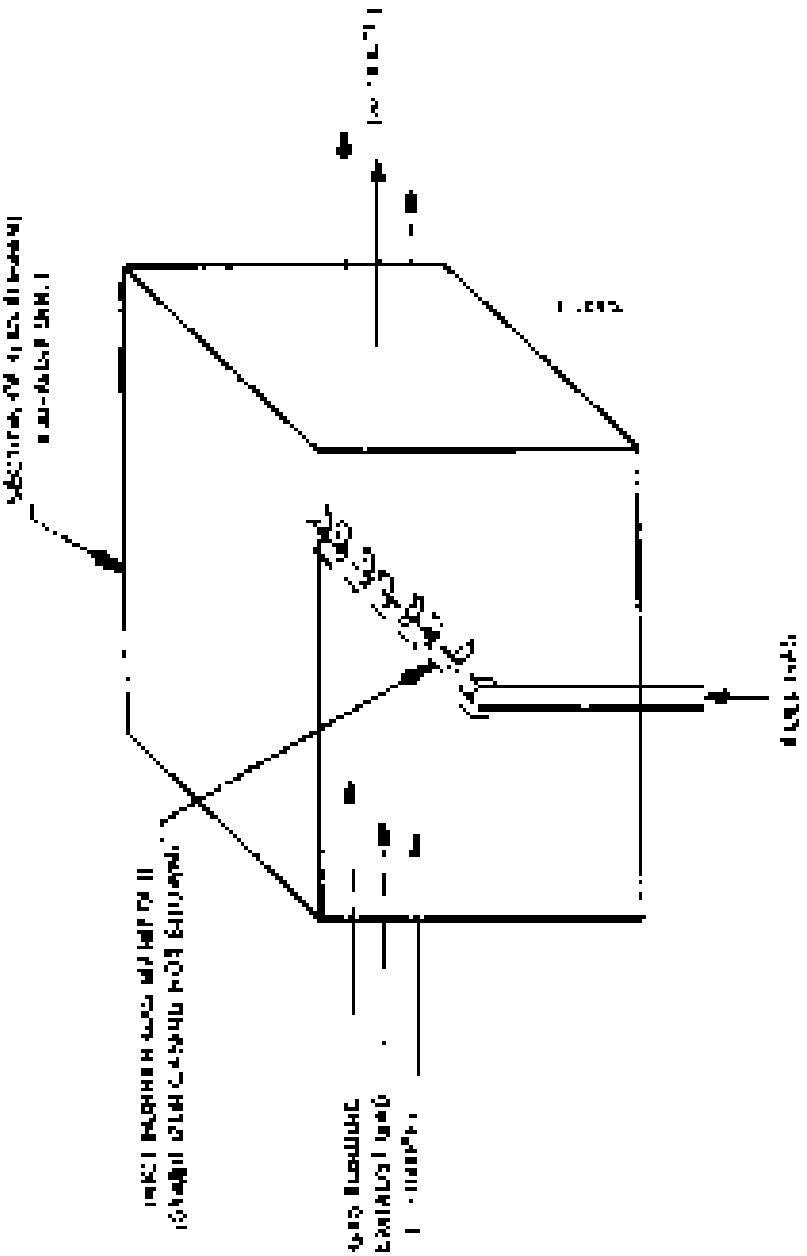


Figure 5-29. Typical duct burner for gas turbine exhaust application.[72]

installation. Figure 5-30 is a cross-sectional view of one style

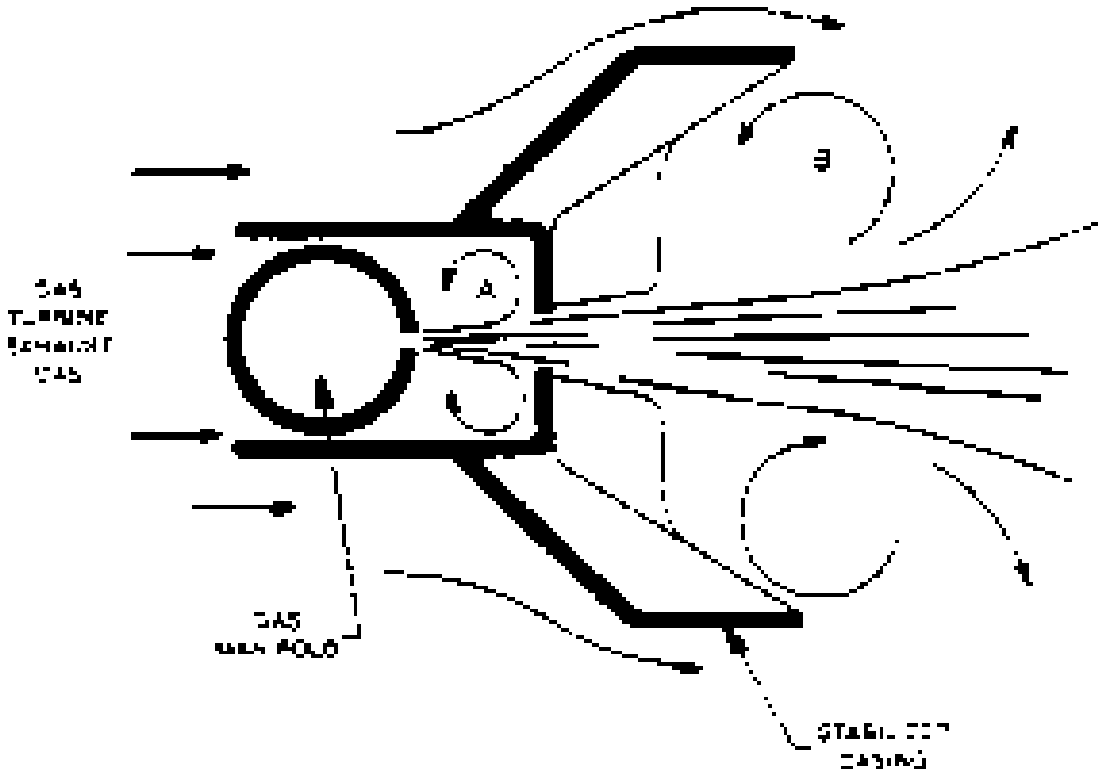


Figure 5-30. Cross-sectional view of a low-NO_x duct burner.[73,74]

of duct burner that incorporates design features to reduce NO_x. In this low-NO_x design, natural gas exits the orifice in the manifold and mixes with the gas turbine exhaust entering through a small slot between the casing and the gas manifold. This mixture forms a jet diffusion flame that causes the recirculation shown in Zone "A." Due to the limited amount of turbine exhaust that can enter Zone A, combustion in this zone is fuel-rich. As the burning gas jet exits into Zone "B," it mixes with combustion products that are recirculated by the flow eddies behind the wings of the stabilizer casing. The flame then expands into the turbine exhaust gas stream, where combustion is completed.

For oil-fired burners, the design principles of the burner are the same. However, the physical layout is slightly different, as shown in

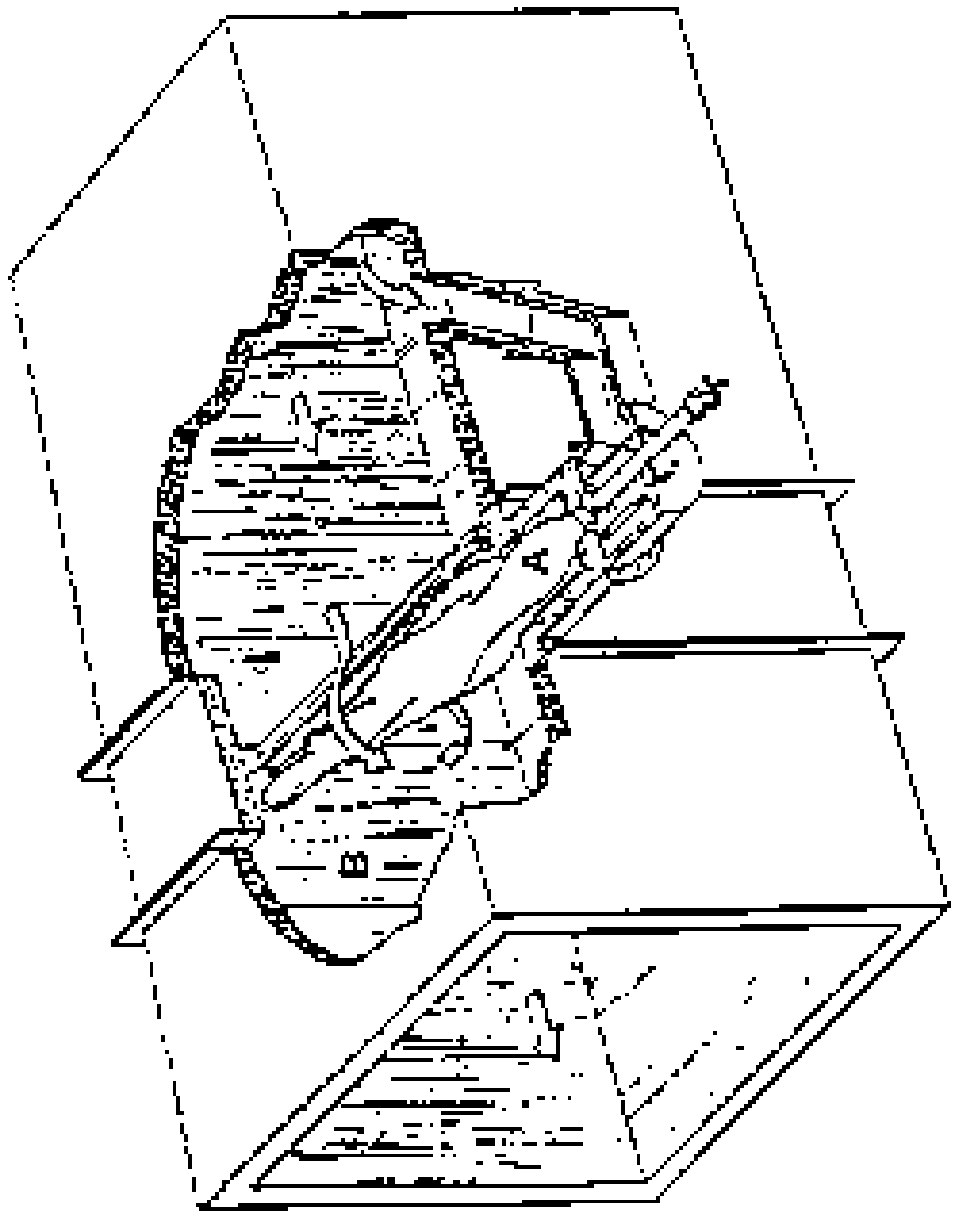


Figure 5-31. Low-NO_x duct burner designed for oil firing.[73,75]

Figure 5-31. Turbine exhaust gas is supplied in substoichiometric quantities by a slip stream duct to the burner. This slip stream supplies the combustion air for the fuel-rich Zone A. The flame shield produces the flow eddies, which recirculate the combustion products into Zone B.[76]

Most duct burners now in service fire natural gas. In all cases, a duct burner will produce a relatively small level of NO_x emissions during operation (See Section 4.2.2), but the net impact on total exhaust emissions (i.e., the gas turbine plus the duct burner) varies with operating conditions, and in some cases may even reduce the overall NO_x emissions. Table 5-19 shows the NO_x emissions measured at one site upstream and downstream of a duct burner. This table shows that NO_x emissions are reduced across the duct burner in five of the eight test runs.

TABLE 5-19. NO_x EMISSIONS MEASURED BEFORE AND AFTER A DUCT BURNER [77]

Gas turbine operation parameters			Duct burner operating parameters		Duct burner inlet		Duct burner outlet		Change across duct burner	
Test No.	Load, MW	Steam/fuel injection ratio, lb/lb	Heat input, MM Btu/hr	Load, percent	NO_x, lb/MM Btu	NO_x, lb/hr	NO_x, lb/MM Btu	NO_x, lb/hr	NO_x, lb/MM Btu	NO_x, lb/hr
1	33.8	0.94	133.8	82.1	0.149	61.4	0.097	55.7	-0.043	-5.7
2	35.0	0.97	93.3	57.3	0.142	58.8	0.113	58.9	0.001	0.1
3	34.5	0.95	40.8	25.0	0.134	57.5	0.118	58.7	0.029	1.2
4	32.0	0.50	137.5	84.4	0.207	85.8	0.151	83.9	-0.014	-1.9
5	32.8	0.46	43.8	26.8	0.228	95.2	0.192	94.0	-0.027	-1.2
6	31.5	0.00	136.7	83.9	0.392	159.7	0.270	156.2	-0.026	-3.5
7	33.0	0.00	42.0	25.8	0.384	166.7	0.313	156.7	-0.238	-10.0
8	11.1	0.00	140.9	86.5	0.157	29.1	0.132	42.1	0.092	13.0

The reason for this net NO_x reduction is not known, but it is believed to be a result of the reburning process in which the intermediate combustion products from the duct burner interact with the NO_x already present in the gas turbine exhaust. The manufacturer of the burner whose emission test results are shown in Table 5-19 states that the following conditions are necessary for reburning to occur:

1. The burner flame must produce a high temperature in a fuel-rich zone;

2. A portion of the turbine exhaust containing NO_x must be introduced into the localized fuel-rich zone with a residence time sufficient for the reburning process to convert the turbine NO_x to N_2 and O_2; and

3. The burner fuel should contain no FBN.[78]

In general, sites using a high degree of supplementary firing have the highest potential for a significant amount of reburning. In practice, only a limited number of sites achieve these reburning conditions due to specific plant operating requirements.[78]

5.6 ALTERNATE FUELS

Because thermal NO_x production is an exponential function of flame temperature (see Section 4.1.1), it follows that using fuels with flame temperatures lower than those of natural gas or distillate oils results in lower thermal NO_x emissions. Coal-derived gas and methanol have demonstrated lower NO_x emissions than more conventional natural gas or oil fuels. For applications using fuels with high FBN contents, switching to a fuel with a lower FBN content will reduce thermal NO_x formation and thereby lower total NO_x emissions.

5.6.1 Coal-Derived Gas

Combustor rig tests have demonstrated that burning coal-derived gas (coal gas) that has been treated to remove FBN produces approximately 30 percent of the NO_x emission levels experienced when burning natural gas. This is because coal gas has a low heat energy level of around 300 Btu or less, which results in a flame temperature lower than that of natural gas.[79] The cost associated with producing coal gas suitable for combustion in a gas turbine has made this alternative economically unattractive, but recent advances in coal gasification technology have renewed interest in this fuel.

A coal gas-fueled power plant is currently operating in the United States at a Dow Chemical plant in Placquemine, Louisiana. This facility operates with a subsidy from the Federal Government, which compensates for the price difference between coal gas and conventional fuels. Several commercial projects have been recently announced using technology developed by Texaco, Shell, Dow Chemical, and the U.S. Department of Energy. Facilities have been permitted for construction in Massachusetts and Delaware.[80]

A demonstration facility, known as Cool Water, operated using coal gas for 5 years in Southern California in the early 1980's. The NO_x emissions were reported at 0.07 lb/MMBtu.[80] Fuel analysis data is not available to convert this NO_x emission level to a ppmv figure. No other emissions data are available.

5.6.2 Methanol

Methanol has a flame temperature of 1925°C (3500°F) versus 2015°C (3660°F) for natural gas and greater than 2100°C (3800°F) for distillate oils. As a result, the NO_x emission levels when burning methanol are lower than those for either natural gas or distillate oils.

Table 5-20 presents NO_x emission data for a full-scale turbine firing methanol.

TABLE 5-20. NO_x EMISSIONS TEST DATA FOR A GAS TURBINE FIRING METHANOL AT BASELOAD[a,81]

Test	W/F ratio, lb/lb	NO_x emissions ISO conditions, ppm at 15% O_2	NO_x reduction, percent[b]
A	0	41	0
B	0	45	0
C	0	48	0
D	0	49	0
E	0	60	0
F	0	47	0
G	0	53	0
H	0	48	0
I	0	51	0
J	0	52	0
K	0	41	0
L	0	47	0
M	0	48	0
AVERAGE		49	
N	0.11	28	42.2
O	0.23	17	65.2
P	0.23	18	62.7
Q	0.24	18	62.7

[a]Baseload = 25 MW output
[b]Calculated using the average of the uncontrolled emissions.

The NO_x emissions from firing methanol without water injection ranged from 41 to 60 ppmv and averaged 49 ppmv. This test also indicated that methanol increases turbine output due to the higher mass flows that result from methanol firing. Methanol firing increased CO and HC emissions slightly compared to the same turbine's firing distillate oil with water injection. All other aspects of turbine performance were as good when firing methanol as when the turbine fired natural gas or distillate oil.[82] Turbine maintenance requirements were estimated to be lower and turbine life was estimated to be longer on methanol fuel than on distillate oil fuel because methanol produced fewer deposits in the combustor and power turbine.

Table 5-20 also presents NO_x emission data for methanol firing with water injection. At water-to-fuel ratios from 0.11 to 0.24, NO_x emissions when firing methanol range from 17 to 28 ppmv, a reduction of 42 to 65 percent.

In a study conducted at an existing 3.2 MW gas turbine installation in 1984, a gas turbine was modified to burn methanol. This study was conducted at the University of California at Davis and was sponsored by the California Energy Commission. A new fuel delivery system for methanol was required, but the only major modifications required for the turbine used in this study were new fuel manifolds and nozzles. Tests conducted burning methanol showed no visible smoke emissions, and only minor increases in CO emissions. Figure 5-32 shows the NO_x emissions measured while burning

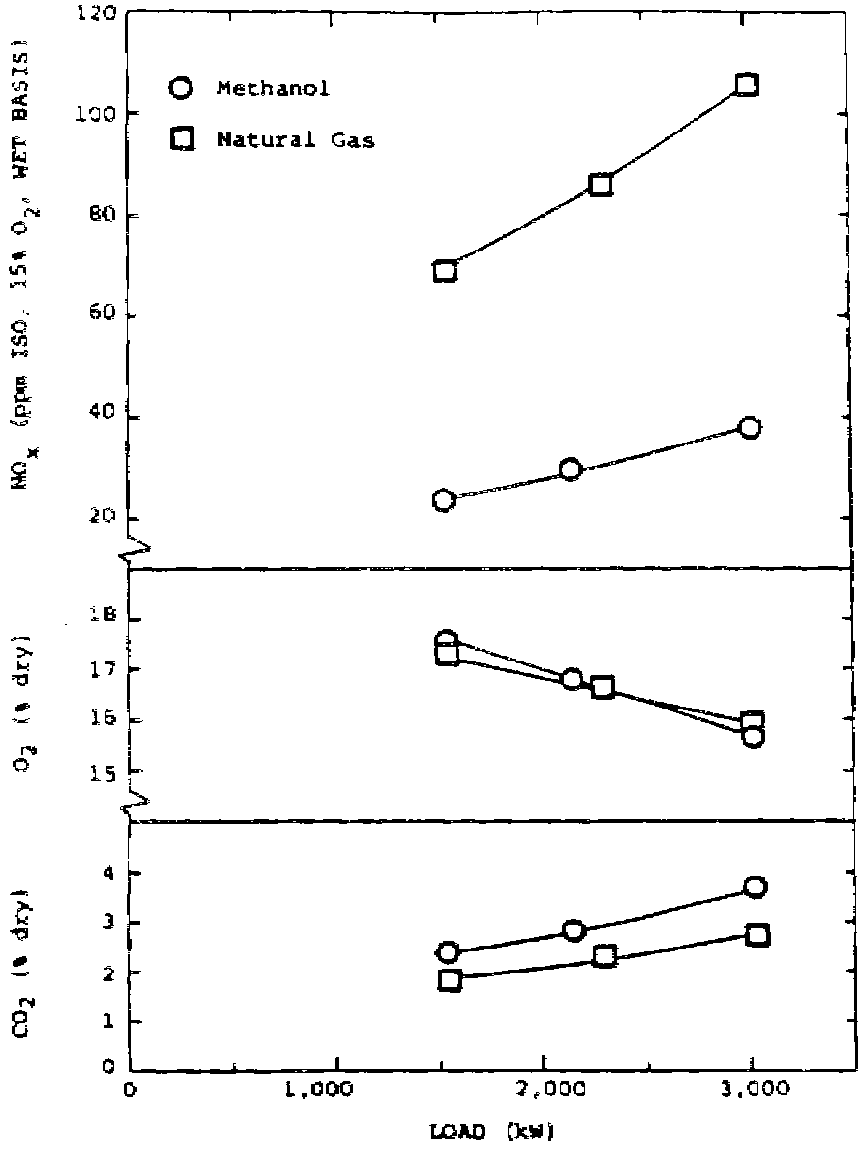


Figure 5-32. Influence of load on NO_x, and CO_2 emissions for methanol and natural gas.[83]

methanol and natural gas. Reductions of up to 65 percent were achieved, as NO_x emissions were 22 to 38 ppm when burning methanol versus

62 to 100 ppm for natural gas. In addition to the intrinsically lower NO_x production, water can be readily mixed with methanol prior to delivery to the turbine to obtain the additional NO_x reduction levels achievable with wet injection. Gas turbine performance characteristics, including startup, acceleration, load changes, and full load power, were all deemed acceptable by the turbine manufacturer.[83]

The current economics of using methanol as a primary fuel are not attractive. There are no confirmed commercial methanol-fueled gas turbine installations in the United States.

5.7 SELECTIVE NONCATALYTIC REDUCTION

Selective noncatalytic reduction (SNCR) is an add-on technology that reduces NO_x using ammonia or urea injection similar to SCR but operates at a higher temperature. At this higher operating temperature of 870° to 1200°C (1600° to 2200°F), the following reaction occurs:[84]

$$NO_x + NH_3 + O_2 + H_2O + (H_2) \rightarrow N_2 + H_2O.$$

This reaction occurs without requiring a catalyst, effectively reducing NO_x to nitrogen and water. The operating temperature can be lowered from 870°C (1600°F) to 700°C (1300°F) by injecting hydrogen (H_2) with the ammonia, as is shown in the above equation.

Above the upper temperature limit, the following reaction occurs:[84]

$$NH_3 + O_2 \rightarrow NO_x + H_2O.$$

Levels of NO_x emissions increase when injecting ammonia or urea into the flue gas at temperatures above the upper temperature limits of 1200°C (2200°F).

Since SNCR does not require a catalyst, this process is more attractive than SCR from an economic standpoint. The operating temperature window, however, is not compatible with gas turbine exhaust temperatures, which do not exceed 600°C (1100°F). Additionally, the residence time required for the reaction is approximately 100 milliseconds, which is relatively slow for gas turbine operating flow velocities.[85]

It may be feasible, however, to initiate this reaction in the gas turbine where operating temperatures fall within the reaction window, if suitable gas turbine modifications and injection systems can be developed.[85] This control technology has not been applied to gas turbines to date.

5.8 CATALYTIC COMBUSTION

5.8.1 Process Description

In a catalytic combustor, fuel and air are premixed into a fuel-lean mixture (fuel/air ratio of approximately 0.02) and then pass into a catalyst bed. In the bed, the mixture oxidizes without forming a high-temperature flame front. Peak combustion temperatures can be limited to below 1540°C (2800°F), which is below the temperature at which significant amounts of thermal NO_x begin to form.[86] An example of a lean catalytic combustor is shown in Figure 5-33.

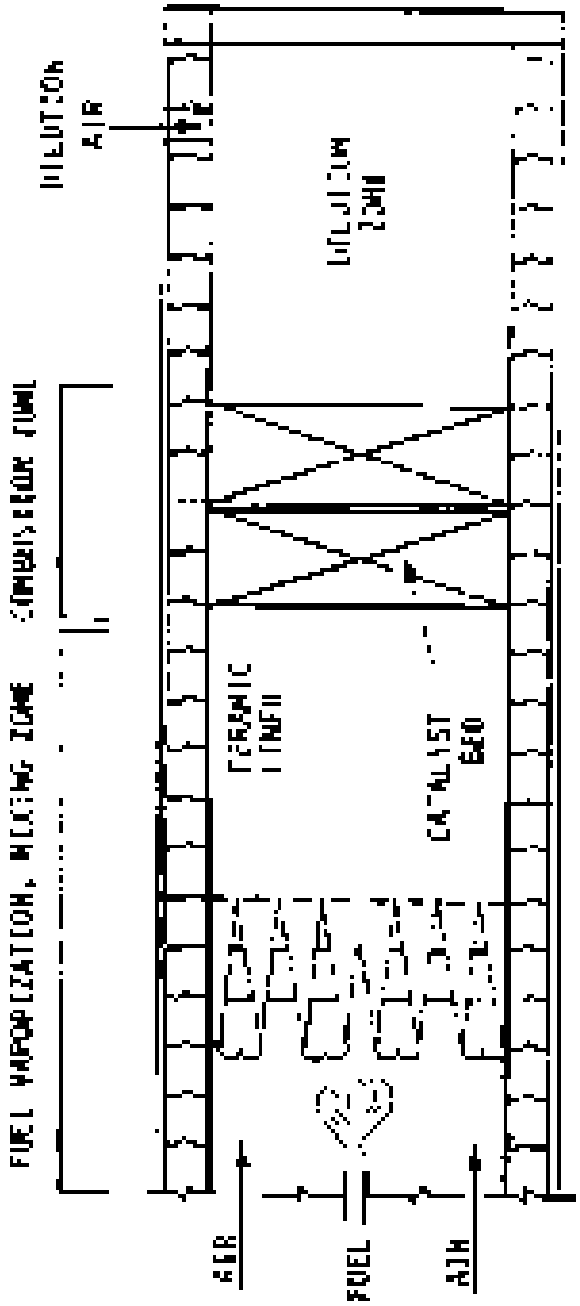


Figure 5-33. A lean catalytic combustor.87

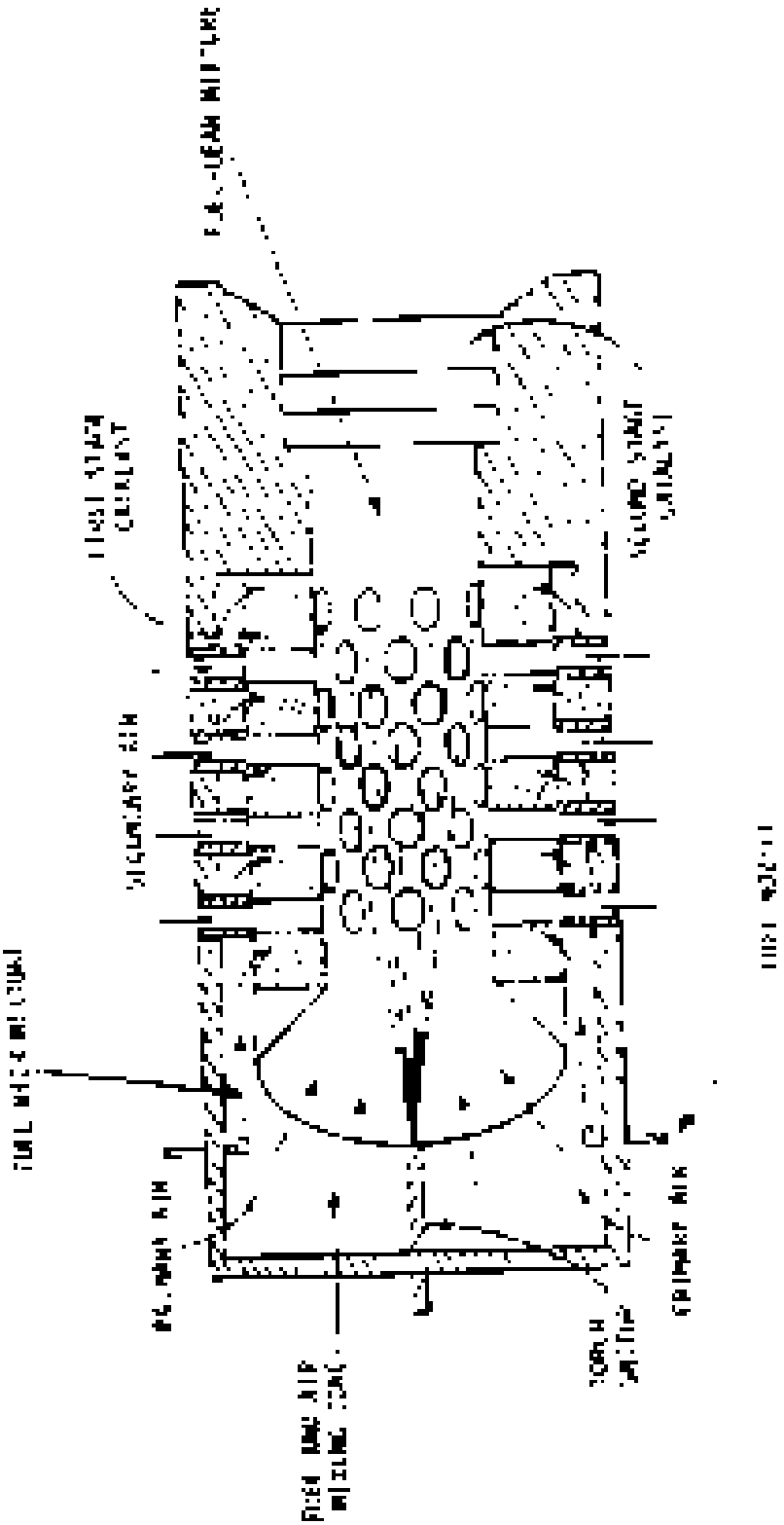


Figure 5-34. A rich/lean catalytic combustor.[89]

Catalytic combustors can also be designed to operate in a rich/lean configuration, as shown in Figure 5-34. In this configuration, the air and fuel are premixed to form a fuel-rich mixture, which passes through a first stage catalyst where combustion begins. Secondary air is then added to produce a lean mixture, and combustion is completed in a second stage catalyst bed.[89]

5.8.2 Applicability

Catalytic combustion techniques apply to all combustor types and are effective on both distillate oil- and natural gas-fired turbines. Because of the limited operating temperature range, catalytic combustors may not be easily applied to gas turbines subject to rapid load changes (such as utility peaking turbines).[90] Gas turbines that operate continuously at base load (such as industrial cogeneration applications) would not be as adversely affected by any limits on load following capability.[91]

5.8.3 Development Status

Presently, the development of catalytic combustors has been limited to bench-scale tests of prototype combustors. The major problem is the development of a catalyst that will have an acceptable life in the high-temperature and -pressure environment

of gas turbine combustors. Additional problems that must be solved are combustor ignition and how to design the catalyst to operate over the full gas turbine operating range (idle to full load).[92]

5.9 OFFSHORE OIL PLATFORM APPLICATIONS

Gas turbines are used on offshore platforms to meet compression and electrical power requirements. This application presents unique challenges for NO_x emissions control due to the duty cycle, lack of a potable water source for wet injection, and limited space and weight considerations. The duty cycle for electric power applications of offshore platforms is unique. This duty cycle is subject to frequent load changes that can instantaneously increase or decrease by as much as a factor of 10.[93] Fluctuating loads result in substantial swings in turbine exhaust gas temperatures and flow rates. This presents a problem for SCR applications because the NO_x reduction efficiency depends upon temperature and space velocity (see Section 5.3.3).

The lack of a potable water supply means that water must be shipped to the platform or sea water must be desalinated and treated. The limited space and weight requirements associated with an SCR system may also have an impact on capital costs of the platform.

A 4-year study is underway for the Santa Barbara County Air Pollution Control Board to evaluate suitable NO_x control techniques for offshore applications. The goals of the study are to reduce turbine NO_x emissions at full load to 9 ppmv, corrected to 15 percent O_2, firing platform gas fuel and to achieve part load reductions of 50 percent. The study consists of two phases. The first phase, an engineering evaluation of available and emerging emission control technologies, is completed. The second phase will select the final control technologies and develop these technologies for offshore platform applications. Phase I

of this study concludes that the technologies with the highest estimated probability for success in offshore applications are:

- Water injection plus SCR (80 percent);
- Methanol fuel plus SCR (70 percent);
- Lean premixed combustion plus SCR (65 percent); and
- Steam dilution of fuel prior to combustion plus SCR (65 percent).

A key conclusion drawn from Phase I of this study is that none of the above technologies or combination of technologies in offshore platform applications currently has a high probability of successfully achieving the NO_x emission reduction goals of this study without substantial cost and impacts to platform and turbine operations, added safety considerations, and other environmental concerns. These issues will be further studied in Phase II for the above control technologies.

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6.0 CONTROL COSTS

Capital and annual costs are presented in this chapter for the nitrogen oxide (NO_x) control techniques described in Chapter 5.0. These control techniques are water and steam injection, low-NO_x combustion, and selective catalytic reduction (SCR) used in combination with these controls. Model plants were developed to evaluate the control techniques for a range of gas turbine sizes, fuel types, and annual operating hours. The gas turbines chosen for these model plants range in size from 1.1 to 160 megawatts (MW) (1,500 to 215,000 horsepower [hp]) and include both aeroderivative and heavy-duty turbines. Model plants were developed for both natural gas and distillate oil fuels. For offshore oil production platforms, cost information was available only for one turbine model.

The life of the control equipment depends upon many factors, including application, operating environment, maintenance practices, and materials of construction. For this study, a 15-year life was chosen.

Both new and retrofit costs are presented in this chapter. For water and steam injection, these costs were assumed to be the same because most of the water treatment system installation can be completed while the plant is operating and because gas turbine nozzle replacement and piping connections to the treated water supply can be performed during a scheduled downtime for maintenance. Estimated costs are provided for both new and retrofit low-NO_x combustion applications. No SCR retrofit applications were identified, and costs for SCR retrofit applications were not available. The cost to retrofit an

existing gas turbine installation with SCR would be considerably higher than the costs shown for a new installation, especially for combined cycle and cogeneration installations where the heat-recovery steam generator (HRSG) would have to be modified or replaced to accommodate the catalyst reactor.

This chapter is organized into five sections. Water and steam injection costs are described in Section 6.1. Low-NO_x combustor costs are summarized in Section 6.2. Costs for SCR used in combination with water or steam injection or low-NO_x combustion are described in Section 6.3. Water injection and SCR costs for offshore gas turbines are presented in Section 6.4, and references are listed in Section 6.5.

a. WATER AND STEAM INJECTION AND OIL-IN-WATER EMULSION

Ten gas turbines models were selected, and from these turbines 24 model plants were developed using water or steam injection or water-in-oil emulsion to control NO_x emissions. These 24 models, shown in Table 6-1

TABLE 6-1. GAS TURBINE MODEL PLANTS FOR NO_x CONTROL TECHNIQUES

Model plant[a]	GT model	Turbine output, MW	Annual operating hours	Fuel, natural gas or oil	Type of emission control	Aeroderivative (AD) or heavy-duty (HD) turbine
CON-G-W-3.3	Centaur T4500	3.3	8,000	Gas	Water	HD
CON-G-W-4.0	501-KB5	4.0	8,000	Gas	Water	AD
CON-G-W-22.7	LM2500	22.7	8,000	Gas	Water	AD
CON-G-W-26.8	MS5001P	26.8	8,000	Gas	Water	HD
CON-G-W-83.3	ABB GT11N	83.3	8,000	Gas	Water	HD
CON-G-W-84.7	MS7001E	84.7	8,000	Gas	Water	HD
CON-G-S-4.0	501-KB5	4.0	8,000	Gas	Steam	AD
CON-G-S-22.7	LM2500	22.7	8,000	Gas	Steam	AD
CON-G-S-26.8	MS5001P	26.8	8,000	Gas	Steam	HD
CON-G-S-34.4	LM5000	34.5	8,000	Gas	Steam	AD
CON-G-S-83.3	ABB GT11N	83.3	8,000	Gas	Steam	HD
CON-G-S-84.7	MS7001E	84.7	8,000	Gas	Steam	HD
CON-G-S-161	MS7001F	161	8,000	Gas	Steam	HD
CON-O-W-3.3	Centaur T4500	3.3	8,000	Oil	Water	HD
CON-O-W-26.3	MS5001P	26.3	8,000	Oil	Water	HD
CON-O-W-83.3	MS7001E	83.3	8,000	Oil	Water	HD
PKR-G-W-3.3	Centaur T4500	3.3	2,000	Gas	Water	HD
PKR-G-W-26.8	MS5001P	26.8	2,000	Gas	Water	HD
PKR-G-W-84.7	MS7001E	84.7	2,000	Gas	Water	HD
PKR-O-W-3.3	Centaur T4500	3.3	2,000	Oil	Water	HD
PKR-O-W-26.3	MS5001P	26.3	2,000	Oil	Water	HD
PKR-O-W-84.7	MS7001E	84.7	2,000	Oil	Water	HD
STD-O-W-1.1	Saturn T1500	1.0	1,000	Oil	Water	HD
STD-O-E-28.0	TPM FT4	28.0	1,000	Oil	Water-in-oil emulsion	AD

[a]Model plant legend:

First entry: annual operating hours
CON--continuous duty, 8,000 hours
PKR--peaking duty, 2,000 hours
STD--stand-by duty, 1,000 hours

Second entry: fuel type
G = natural gas fuel
O = oil fuel

Third entry: control type
W = water injection
S = steam injection
E = water-in-oil emulsion

Fourth entry: power output in MW

For example, CON-G-W-3.3 designates that the model plant is continuous-duty, uses natural gas fuel, has water injection, and has a power output of 3.3 MW.

, characterize variations in existing units with respect to turbine size, type (i.e., aero-derivative vs. heavy duty), operating hours, and type of fuel. A total of 24 model plants were developed; 16 of these were continuous-duty (8,000 hours per year) and 8 were intermittent-duty (2,000 or 1,000 hours per year). Thirteen of the continuous-duty model plants burn natural gas fuel; 6 of the 13 use water injection, and 7 use steam injection to reduce NO_x emissions. The three remaining continuous-duty model plants burn distillate oil fuel and use water injection to reduce NO_x emissions. Of the eight intermittent-duty model plants, six operate 2,000 hours per year (three natural gas-fueled and three distillate oil-fueled), and two operate 1,000 hours per year (both distillate oil-fueled). All intermittent-duty model plants use water rather than steam for NO_x reduction because it was assumed that the additional capital costs associated with steam-generating equipment could not be justified for intermittent service.

Costs were available for applying water-in-oil emulsion technology to only one gas turbine, and insufficient data were available to develop costs for a similar water-injected model

plant for this turbine. As a result, the costs and cost effectiveness for the water-in-oil emulsion model plant should not be compared to those of water-injected model plants.

Capital costs are described in Section 6.1.1, annual costs are described in Section 6.1.2, and emission reductions and the cost effectiveness of wet injection controls are discussed in Section 6.1.3. Additional discussion of the cost methodology and details about some of the cost estimating procedures are provided in Appendix B.

Fuel rates and water flow rates were calculated for each model plant using published design power output and efficiency, expressed as heat rate, in British thermal units per kilowatt-hour (Btu/kWh).[1] The values for these parameters are presented in Table 6-2

TABLE 6-2. FUEL AND WATER FLOW RATES FOR WATER AND STEAM INJECTION (1990 $)

Model plant	GT model	Turbine output, kW	Heat rate (HR), Btu/kW-hr	Fuel flow		Estimated WFR, lb water/lb fuel	Water flow, gal/min[c]	Treatment system capacity, gal/min[d]
				lb/hr[a]	MMBtu/yr[b]			
CON-G-W-3.3	Centaur T4500	3,270	12,900	2,050	337,000	0.61	2.50	4.20
CON-G-W-4.0	501-KB5	4,000	12,700	2,460	406,000	0.80	3.94	6.60
CON-G-W-22.7	LM2500	22,670	9,220	10,100	1,670,000	0.73	14.8	24.7
CON-G-W-26.8	MS5001P	26,800	11,870	15,400	2,540,000	0.72	22.2	37.2
CON-G-W-83.3	ABB GT11N	83,300	10,400	42,000	6,930,000	1.83	154	258
CON-G-W-84.7	MS7001E	84,700	10,400	42,700	7,050,000	0.81	69.2	116
CON-G-S-4.0	501-KB5	4,000	12,700	2,460	406,000	1.50	7.38	12.4
CON-G-S-22.7	LM2500	22,670	9,220	10,100	1,670,000	1.46	29.5	49.5
CON-G-S-26.8	MS5001P	26,800	11,870	15,400	2,540,000	1.08	33.3	55.8
CON-G-S-34.4	LM5000	34,450	9,080	15,200	2,500,000	1.67	50.8	85.2
CON-G-S-83.3	ABB GT11N	83,300	10,400	42,000	6,930,000	2.12	178	299
CON-G-S-84.7	MS7001E	84,700	10,400	42,700	7,050,000	1.22	104	175
CON-G-S-161	MS7001F	161,000	9,500	74,200	12,240,000	1.34	199	334
CON-O-W-3.3	Centaur T4500	3,270	12,900	2,300	337,000	0.60	2.76	4.63
CON-O-W-26.3	MS5001P	26,300	11,950	17,100	2,510,000	0.79	27.0	45.3
CON-O-W-83.3	MS7001E	83,300	10,470	47,600	6,980,000	0.67	63.8	107
PKR-G-W-3.3	Centaur T4500	3,270	12,900	2,050	84,400	0.61	2.50	4.20
PKR-G-W-26.8	MS5001P	26,800	11,870	15,400	640,000	0.72	22.2	37.2
PKR-G-W-84.7	MS7001E	84,700	10,400	42,700	1,760,000	0.81	69.2	116
PKR-O-W-3.3	Centaur T4500	3,270	12,900	2,300	84,000	0.60	2.76	4.63
PKR-O-W-26.3	MS5001P	26,300	11,950	17,100	630,000	0.79	27.0	45.3
PKR-O-W-84.7	MS7001E	83,300	10,470	47,600	1,740,000	0.67	63.8	107
STD-O-W-1.1	Saturn T1500	1,130	14,200	875	16,000	0.46	0.81	1.35
STD-O-F-28.0	TPM FT4	28,000	14,500	19,700	406,000	0.55	21.7	36.4

[a]Natural gas: lb/hr = HR x kW x (lb/20,610 Btu). Diesel oil: lb/hr = HR x kW x (lb/18,330 Btu).

[b]MMBtu/yr = HR x kW x (MM/10^6) x (operating hours/year).

[c]Water (or steam) flow, gal/min = Fuel flow (lb/hr) x (1 hr/60 min) x (1 gal/8.33, lb. H_2O) x WFR.

[d]A 30 percent design factor has been included per discussion with system supplier, and the waste stream from the water treatment system is calculated to be 29 percent. The design capacity is therefore Water Flow x 1.3 x 1.29.

for each model plant. Fuel rates were estimated based on the heat rates, the design output, and the lower heating value (LHV) of the fuel. The LHV's used in this analysis for natural gas and diesel fuel are 20,610 Btu per pound (Btu/lb) and 18,330 Btu/lb, respectively, as shown in Table 6-3

TABLE 6-3. FUEL PROPERTIES AND UTILITY AND LABOR RATES[a]

Fuel properties	Factor	Units	Reference
Natural gas	20,610	Btu/lb	Ref. 3
	930	Btu/scf[c] (LHV)	Ref. 3
Diesel fuel	18,330	Btu/lb (LHV)	Ref. 2
	7.21	lb/gal	Ref. 2
Utility rates			
Natural gas[b]	3.88	$/scf	Ref. 4
Diesel fuel	0.77	$/gal	Ref. 5
Electricity	0.06	$/kW-hr	Ref.'s 6 and 7
Raw water	0.384	$/1,000 gal	Ref. 2, escalated @ 5% per year
Water treatment	1.97	$/1,000 gal	Ref. 2, escalated @ 5% per year
Waste disposal	3.82	$/1,000 gal	Ref. 2, escalated @ 5% per year
Labor rate			
Operating	25.60	$/hr	Ref. 2, escalated @ 5% per year
Maintenance	31.20	$/hr	Ref. 2, escalated @ 5% per year

[a]All costs are average costs in 1990 dollars.
[b]Natural gas and electricity costs from Reference 4 are the average of the costs for industrial and commercial customers.
[c]scf = standard cubic foot.

.[2] Water (or steam) injection rates were calculated based on published fuel rates and water-to-fuel ratios (WFR) provided by manufacturers.[8-12] According to a water treatment system supplier, treatment facilities are designed with a capacity factor of 1.3.[13] An additional 29 percent of the treated water flow rate is discarded as wastewater.[2] Consequently, the water treatment facility design capacity is 68 percent (1.30 x 1.29) greater than the water (or steam) injection rate.

i. Capital Costs

The capital costs for each model plant are presented in Table 6-4

TABLE 6-4. CAPITAL COSTS FOR WET INJECTION IN THOUSAND OF DOLLARS [a]

Model plant	GT model	Injection system (IS)[b]	Water treatment system (WTS)[c]	Total system (TS) = (IS + WTS)	Taxes and freight (TF) = (8% of TS)	Direct install. costs (DC) = (45% [TS + TF])	Indirect install. costs (IC)=(33% of [TS + TF +DC] + 5,000)	Contingency (C) = (20% of [TS + TF + DC + IC])	Total capital cost (TCC) = [TS + TF + DC + IC + C]
CON-G-W-3.3	Centaur T4500	113	89.9	203	16.2	50.0[d]	53.8[e]	64.6	388
CON-G-W-4.0	501-KB5	115	113	228	18.2	50.0[d]	59.2[e]	71.0	426
CON-G-W-22.7	LM2500	212	218	430	34.4	209	227	180	1,080
CON-G-W-26.8	MS5001P	215	268	483	38.6	235	254	202	1,210
CON-G-W-83.3	ABB GT11N	874	705	1,580	126	768	822	659	3,950
CON-G-W-84.7	MS7001E	562	473	1,030	82.4	501	537	430	2,580
CON-G-S-4.0	501-KB5	154	154	308	24.7	50.0	76.6	92.0	552
CON-G-S-22.7	LM2500	278	309	587	46.9	285	308	245	1,470
CON-G-S-26.8	MS5001P	262	328	590	47.2	287	310	247	1,480
CON-G-S-34.4	LM5000	530	405	935	74.8	454	488	391	2,340
CON-G-S-83.3	ABB GT11N	1,090	759	1,850	148	899	961	772	4,630
CON-G-S-84.7	MS7001E	715	580	1,300	104	632	677	543	3,260
CON-G-S-161	MS7001F	1,130	802	1,930	154	938	1,000	804	4,830
CON-O-W-3.3	Centaur T4500	114	94.5	208	16.7	50.0[d]	55.0[e]	66.0	396
CON-O-W-26.3	MS5001P	231	296	527	42.1	256	277	220	1,320
CON-O-W-83.3	MS7001E	532	454	986	78.9	479	515	412	2,470
PKR-G-W-3.3	Centaur T4500	113	89.9	203	16.2	50.0[d]	53.8[e]	64.6	388
PKR-G-W-26.8	MS5001P	215	268	483	38.6	235	254	202	1,210
PKR-G-W-84.7	MS7001E	562	473	1,030	82.4	501	537	430	2,580
PKR-O-W-3.3	Centaur T4500	114	94.5	208	16.7	50.0[d]	55.0[e]	66.0	396
PKR-O-W-26.3	MS5001P	231	296	527	42.1	256	277	220	1,320
PKR-O-W-84.7	MS7001E	532	454	986	78.9	479	515	412	2,470
STD-O-W-1.1	Saturn T1500	71.9	51.0	123	9.83	50.0	36.6	43.9	263
STD-O-F-28.0	TPM FT4	128	NA[f]	128	10.2	62.2	71.1	54.3	326

[a]All costs in 1990 dollars.

[b]Injection nozzle costs provided by manufacturers. Balance of water injection system calculated at a cost of $4,200 x GPM.

[c]WTS = 43,900 x (design capacity, gal/min) $^{0.5}$

[d]Direct installation cost is estimated at $50,000 for model plants rated at 5 MW or less.

[e]Indirect installation cost factor of 33 percent is reduced to 20 percent for model plants rated at 5 MW or less.

[f]NA = cost calculations based on using a portable demineralizer systems during turbine operating periods. Cost for system usage is included in Table 6-5.

. These costs were developed based on methodology in Reference 2, which is presented in this section. The capital costs include purchased equipment costs, direct and indirect installation costs, and contingency costs.

(1) Purchased Equipment Costs. Purchased equipment costs consist of the injection system, the water treatment system, taxes, and freight. All costs are presented in 1990 dollars.

(a) Water injection system. The injection system delivers water from the treatment system to the combustor. This system includes the turbine-mounted injection nozzles, the flow metering controls, pumps, and hardware and interconnecting piping from the treatment system to the turbine. On-engine hardware (the injection nozzles) costs were provided by turbine manufacturers.[9,14-17] Flow metering controls and hardware, pumps, and interconnecting piping costs for all turbines were calculated using data provided by General Electric for four heavy-duty turbine models.[17] No relationship between costs and either turbine output or water flow was evident, so the sum of the four costs was divided by the sum of the water flow requirements for the four turbines. This process yielded a cost of $4,200 per gallon per minute (gal/min), and this cost, added to the on-engine hardware costs, was used for all model plants.

(b) Water treatment system. The water treatment process, and hence the treatment system components, varies according to the degree to which the water at a given site must be treated. For this cost analysis, the water treatment system includes a reverse osmosis and mixed-bed demineralizer system. The water treatment system capital cost for each model plant was estimated based on an equation developed in Reference 2:

$$WTS = 43{,}900 \times (G)^{0.50}$$

where

WTS = water treatment system capital cost, $; and

G = water treatment system design capacity, gal/min.

This equation yields costs that are generally consistent with the range of costs presented in Reference 18.

(c) Taxes and freight. This cost covers applicable sales taxes and shipment to the site for the injection and water treatment systems. A figure of 8 percent of the total system cost was used.[2,7]

(2) Direct Installation Costs. This cost includes the labor and material costs associated with installing the foundation and supports, erecting and handling equipment, electrical work, piping, insulation, and painting. For smaller

turbines, the water treatment system is typically skid-mounted and is shipped to the site as a packaged unit, which minimizes field assembly and interconnections. The cost to install a skid-mounted water treatment skid is typically $50,000, and this cost is used for the direct installation cost for model plants less than 5 MW (6700 hp).[19] For larger turbines, it is expected that the water treatment system must be field-assembled and the direct installation costs were calculated as 45 percent of the injection and water treatment systems, including taxes and freight.[2]

(3) Indirect Installation Costs. This cost covers the indirect costs (engineering, supervisory personnel, office personnel, temporary offices, etc.) associated with installing the equipment. The cost was taken to be 33 percent of the systems' costs, taxes and freight, and direct costs, plus $5,000 for model plants above 5 MW (6,700 hp).[2] The indirect installation costs for skid-mounted water treatment systems are expected to be less than for field-assembled systems; therefore, for model plants with an output of less than 5 MW (6,700 hp), the cost percentage factor was reduced from 33 to 20 percent.

(4) Contingency Cost. This cost is a catch-all meant to cover unforeseen costs such as equipment redesign/ modification, cost escalations, and delays encountered in startup. This cost was estimated as 20 percent of the sum of the systems, taxes and freight, and direct and indirect costs.[2]

ii. Annual Costs

The annual costs are summarized in Table 6-5

TABLE 6-5. ANNUAL COSTS FOR WATER AND STEAM INJECTION (1990 $)

Model plant	GT model	Fuel penalty (FP)[a]	Electricity (E)[b]	Added maintenance cost (M)[c]	Water treatment (WT)[d]					Plant overhead (PO) = (30% of M)	G&A taxes, insurance (GATI)[i]	Capital recovery (CR)[j]	Total annual cost (TAC)[k]
					Raw water[e]	Treat-ment[f]	Labor[g]	Disposal[h]	Total cost (TW)				
CON-G-W-3.3	Centaur T4500	30,000	193	16,000	595	3,050	1,080	1,330	6,050	4,800	15,500	51,000	124,000
CON-G-W-4.0	501-KB5	47,400	304	24,000	936	4,800	1,710	2,090	9,540	7,200	17,100	56,100	162,000
CON-G-W-22.7	LM2500	178,000	1,140	28,000	3,510	18,000	6,390	7,840	35,700	8,400	43,200	142,000	436,000
CON-G-W-26.8	MS5001P	267,000	1,714	33,000	5,270	27,100	9,620	11,800	53,800	9,900	48,400	159,000	573,000
CON-G-W-83.3	ABB GT11N	1,852,000	11,884	0	36,600	188,000	66,700	81,800	373,000	0	158,000	519,000	2,910,000
CON-G-W-84.7	MS7001E	834,000	5,348	25,700	16,500	84,400	30,000	36,800	168,000	7,710	103,000	339,000	1,480,000
CON-G-S-4.0	501-KB5	25,400	571	24,000	1,760	9,010	1,600	3,930	16,300	7,200	22,100	72,600	168,000
CON-G-S-22.7	LM2500	102,000	2,280	0	7,020	36,000	6,390	15,700	65,100	0	58,800	193,000	421,000
CON-G-S-26.8	MS5001P	114,000	2,572	33,000	7,910	40,600	7,210	17,700	73,400	9,900	59,200	195,000	487,000
CON-G-S-34.4	LM5000	174,000	3,925	0	12,100	62,000	11,000	27,000	112,000	0	93,600	308,000	692,000
CON-G-S-83.3	ABB GT11N	613,000	13,768	0	42,400	217,000	38,600	94,700	393,000	0	185,000	609,000	1,810,000
CON-G-S-84.7	MS7001E	359,000	8,055	0	24,800	127,000	22,600	55,400	230,000	0	130,000	429,000	1,160,000
CON-G-S-161	MS7001F	684,000	15,374	0	47,300	243,000	43,100	106,000	439,000	0	193,000	635,000	1,970,000
CON-O-W-3.3	Centaur T4500	41,200	213	20,800	657	3,370	1,200	1,470	6,700	6,240	15,800	52,100	143,000
CON-O-W-26.3	MS5001P	404,000	2,089	42,900	6,430	33,000	11,700	14,400	65,500	12,900	52,800	174,000	754,00
CON-O-W-83.3	MS7001E	954,000	4,931	33,400	15,200	77,800	27,700	33,900	155,000	10,020	98,800	325,000	1,580,000
PKR-G-W-3.3	Centaur T4500	7,500	48.3	4,000	149	760	270	330	1,510	1,200	15,500	51,000	80,800
PKR-G-W-26.8	MS5001P	67,000	429	8,250	1,320	6,770	2,400	2,950	13,400	2,500	48,400	159,000	299,000
PKR-G-W-84.7	MS7001E	208,000	1,337	6,430	4,110	21,100	7,500	9,200	41,900	1,929	103,000	339,000	702,000
PKR-O-W-3.3	Centaur T4500	10,300	53.3	5,200	164	840	300	370	1,670	1,560	15,800	52,100	86,700
PKR-O-W-26.3	MS5001P	101,000	522	10,725	1,610	8,240	2,930	3,590	16,400	3,200	52,800	174,000	359,000
PKR-O-W-84.7	MS7001E	238,000	1,233	8,350	3,790	19,500	6,910	8,480	38,700	2,505	99,000	325,000	713,000
STD-O-W-1.1	Saturn T1500	1,500	7.78	1,300	23.9	123	43.7	53.6	244	390	10,530	34,600	48,600
STD-O-E-28.0	TPM FT4	45,500	209	0	644	51,100	1,170	1,440	54,400	0	13,000	42,900	156,000

[a]FP for water = 0.035 x WFR x (MMBtu/yr) x (ft ^{3}/940 Btu) x ($3.88/1,000 ft ^{3}) x (10^6/MM).
[b]E = Water flow rate (gal/min) x 0.161 x operating hours x ($0.06/kWH).
[c]Maintenance costs for the Centaur and Allison 501 turbines were obtained from the manufacturers. Costs for the MS5001 and MS7001 were estimated based on information about inspections and parts replacement presented in Appendix B. Maintenance for turbines that use diesel fuel are 30 percent higher than costs for comparable turbines using natural gas. No additional maintenance costs were assessed for steam injection.
[d]WT includes treatment chemicals, raw water, sewage disposal, and operating labor.
[e]Raw Water Cost = Water Flow (gal/min) x ($0.384/1,000 gal) x (60 min/hour) x operating hours x 1.29.
[f]Treatment Cost = Water Flow (gal/min) x ($1.97/1,000 gal) x (60 min/hour) x operating hours x 1.29.
[g]Labor Cost for water = Water Flow (gal/min) x ($.70/1,000 gal) x (60 min/hour) x operating hours x 1.29.
Labor Cost for steam = Water Flow (gal/min) x ($.70/1,000 gal) x (60 min/hour) x operating hours x 1.29 x 0.5.
[h]Disposal Cost = Water Flow (gal/min) x ($3.82/1,000 gal) x (60 min/hour) x operating hours x 0.29.
[i]GATI = 0.04 x TCC (TCC is shown in Table 6-4).
[j]CR = 0.1315 x TCC based on an equipment life of 15 years and a 10 percent interest rate.

for each model plant. Annual costs include the fuel penalty; electricity; maintenance requirements; water treatment; overhead, general and administrative, taxes, and insurance; and capital recovery, as discussed in this section.

(1) Fuel Penalty. The reduction in efficiency associated with water injection varies for each turbine model. Based on data in Reference 2, it was estimated that a WFR of 1.0 corresponds to a fuel penalty of 3.5 percent for water injection and 1.0 percent for steam injection. This percentage was multiplied by the actual WFR and the annual fuel cost to

determine the fuel penalty for each model plant. The fuel flow was multiplied by the unit fuel costs to determine the annual fuel costs. As shown in Table 6-3, the natural gas cost is $3.88/1,000 standard cubic feet (scf) and the diesel fuel cost is $0.77/gal.[4,5]

An increase in output from the turbine accompanies the decrease in efficiency. This increase was not considered, however, because not all sites have a demand for the available excess power. In applications such as electric power generation, where the excess power can be used at the site or added to utility power sales, this additional output would serve to decrease or offset the fuel penalty impact.

(2) Electricity Cost. The electricity costs shown in Table 6-5 apply to the feedwater pump(s) for water or steam injection. The pump power requirements are estimated from the pump head (ft) and the water flow rate as shown in the following equation:[2]

$$\text{power pump } (kW_e) = \frac{FR}{3{,}960} \times H \times (S.G.) \times \frac{1}{0.6} \times \frac{0.7457\ kW}{hp} \times \frac{1}{0.9}$$

where:

FR = feedwater flow rate, gal/min (from Table 6-2);
H = total pump head (ft);
S.G. = specific gravity of the feed water;
0.6 = pump efficiency of 60 percent;
0.9 = electric motor efficiency of 90 percent;
3,960 = factor to correct units in FR and H to hp; and
0.7457 = factor to convert hp to kW.

For water injection, the feedwater pump(s) supply treated water to the gas turbine injection system. For steam injection, the feedwater pump(s) supply treated water to the boiler for steam generation. This cost analysis uses a feedwater temperature of 55°C (130°F) with a density of 61.6 lb/ft^3 and a total pump head requirement of 200 pounds per square inch, gauge (psig)

(468 ft).[2] Based on these values, the pump electrical demand for either water or steam injection is calculated as follows:

$$\text{pump power } (kW_e) = \frac{FR \times 468}{3{,}960} \times \frac{61.6}{62.4} \times \frac{1}{0.6} \times 0.7457 \times \frac{1}{0.9}$$

$$= 0.161 \times FR$$

The electrical cost for each model plant is the product of the pump electrical demand, the annual hours of operation, and the unit cost of electricity. The unit cost of electricity, shown in Table 6-3, is $0.06/kWH.[6,7]

Maintenance costs were developed based on information from manufacturers, and water treatment labor costs were estimated based on information from a water treatment vendor. Other costs were developed based on the methodology presented in Reference 2.

No backup steam or electricity costs were developed for water or steam injection because it was assumed that no additional downtime would be required for scheduled inspections and repairs. Maintenance intervals could be scheduled to coincide with the 760 hr/yr of downtime that are currently allocated for scheduled maintenance. If this were done, the annual utilization of the backup source would not increase.

(3) Added Maintenance Costs. Based on discussions with gas turbine manufacturers, additional maintenance is required for some gas turbines with water injection. The analysis procedures used to develop the incremental maintenance costs are presented in Appendix B.

The incremental maintenance cost associated with water injection for natural gas-fueled turbines was provided by the gas turbine manufacturers.[10,20-24] All gas turbine manufacturers contacted stated that there were no incremental maintenance costs for operation with steam injection. Two manufacturers provided maintenance costs for natural gas and oil fuel operation without water injection.[10,20] Using an average of these costs, incremental maintenance costs for water injection are 30 percent higher for

plants that use diesel fuel instead of natural gas. Costs were prorated for model plants that operate less than 8,000 hr/yr.

(4) Water Treatment Costs. Water treatment operating costs include the cost of treatment (e.g., for chemicals and media filters), operating labor, raw water, and wastewater disposal. The raw water flow rate is equal to the treated water flow rate (the water or steam injection rate) plus the flow rate of the wastewater generated in the treatment plant. As noted in Section 6.1, the wastewater flow rate is equal to 29 percent of the injection flow rate. The annual raw water, treated water, and wastewater flow rates were multiplied by the appropriate unit costs in Table 6-3 to determine the annual costs. Water treatment labor costs were calculated at $0.70/1,000 gal for water injection.[25] This cost was multiplied by the total annual treated water flow rate to determine the annual water treatment labor cost for water injection. Labor costs for steam injection were assumed to be half as much as the costs for water injection because it was assumed that the facility already has a water treatment plant for the boiler feedwater. Therefore, the operator requirements would be only those associated with the increase in capacity of the existing treatment plant.

(5) Plant Overhead. This cost is the overhead associated with the additional maintenance effort required for water injection. The cost was calculated as 30 percent of the added maintenance cost from Section 6.1.2.3.[2]

(6) General and Administrative, Taxes, and Insurance Costs (GATI). This cost covers those expenses for administrative overhead, property taxes, and insurance and was calculated as 4 percent of the total capital cost.[2]

(7) Capital Recovery. A capital recovery factor (CRF) was multiplied by the total capital investment to estimate uniform end-of-year payments necessary to repay the investment. The CRF used in this analysis is 0.1315, which is based on an equipment life of 15 years and an interest rate of 10 percent.

(8) Total Annual Cost. This cost is the sum of the annual costs presented in Sections 6.1.2.1 through 6.1.2.7 and is the

total cost that must be paid each year to install and operate water or steam injection NO_x emissions control for a gas turbine.

iii. Emission Reduction and Cost-Effectiveness Summary for Water and Steam Injection

TABLE 6-6. COST-EFFECTIVENESS SUMMARY FOR WATER AND STEAM INJECTION (1990 $)

Model plant	GT model	NO_x emissions[a]				Total NO_x removed, tons/yr	Total annual cost, $	Cost effectiveness, $/ton
		Uncontrolled NO_x		Controlled NO_x				
		ppmv[b]	tons/yr	ppmv	[b] tons/yr			
CON-G-W-3.3	Centaur T4500	130	88.1	42	28.5	59.6	124,000	2,080
CON-G-W-4.0	501-KB5	155	126	42	34.2	91.9	162,000	1,760
CON-G-W-22.7	LM2500	174	581	42	140	441	436,000	989
CON-G-W-26.8	MS5001P	142	723	42	214	509	573,000	1,130
CON-G-W-83.3	ABB GT11N	390	5,410	25	347	5,060	2,910,000	575
CON-G-W-84.7	MS7001E	154	2,170	42	593	1,580	1,480,000	937
CON-G-S-4.0	501-KB5	155	126	42	34.2	91.9	168,000	1,830
CON-G-S-22.7	LM2500	174	581	25	83.5	497	421,000	846
CON-G-S-26.8	MS5001P	142	723	42	214	509	487,000	957
CON-G-S-34.4	LM5000	185	930	25	126	804	692,000	861
CON-G-S-83.3	ABB GT11N	390	5,410	42	583	4,830	1,810,000	375
CON-G-S-84.7	MS7001E	154	2,170	42	593	1,580	1,160,000	734
CON-G-S-161	MS7001F	210	5,150	42	1,030	4,120	1,970,000	478
CON-O-W-3.3	Centaur T4500	179	125	60	41.8	82.9	143,000	1,720
CON-O-W-26.3	MS5001P	211	1,090	65	337	753	754,000	1,000
CON-O-W-83.3	MS7001E	228	3,290	65	938	2,350	1,580,000	672
PKR-G-W-3.3	Centaur T4500	130	22.0	42	7.12	14.9	80,800	5,420
PKR-G-W-26.8	MS5001P	142	181	42	53.5	127	299,000	2,350
PKR-G-W-84.7	MS7001E	154	543	42	148	395	702,000	1,780
PKR-O-W-3.3	Centaur T4500	179	31.2	60	10.5	20.7	86,700	4,180
PKR-O-W-26.3	MS5001P	211	273	65	84.2	189	359,000	1,900
PKR-O-W-84.7	MS7001E	228	822	65	234	588	713,000	1,210
STD-O-W-1.1	Saturn T1500	150	4.97	60	1.99	2.98	48,600	16,300
STD-O-E-28.0	TPM FT4	150	122	50	37.3	84.7	156,000	1,840

[a]Example NO_x emission calculations are given in Appendix A.

[b]Referenced to 15 percent oxygen.

[c]From Table 6-5.

The uncontrolled and controlled NO_x emissions and the annual emission reductions for the model plants are shown in Table 6-6. The emissions, in tons per year (tons/yr), were calculated as shown in Appendix A.

The total annual cost was divided by the annual emission reductions to determine the cost effectiveness for each model plant. For continuous-duty natural gas-fired model plants, the cost-effectiveness figures range from approximately $600 to $2,100 per ton of NO_x removed for water injection, and decrease to approximately $400 to $1,850 per ton for steam injection. The lower range of cost-effectiveness figures for steam injection is primarily due to the greater NO_x reduction achieved with steam injection. For continuous-duty oil-fired model plants, the cost effectiveness ranges from approximately $675 to $1,750 per ton of NO_x removed, which is comparable to figures for gas-fired model plants. The cost-effectiveness figures are higher for gas turbines with lower power outputs because the fixed capital costs associated with wet injection system installation have the greatest impact on the smaller gas turbines.

Cost-effectiveness figures increase as annual operating hours decrease. For turbines operating 2,000 hr/yr, the cost-effectiveness figures are two to nearly three times higher than those for continuous-duty model plants, and increase further for model plants operating 1,000 hr/yr. For the oil-in-water emulsion model plant, the cost effectiveness corresponding to 1,000 annual operating hours is $1,840/ton of NO_x removed. No data were available to prepare a conventional water injection model plant for this turbine to compare the relative cost-effectiveness values.

b. LOW-NO_x COMBUSTORS

Incremental capital costs for low-NO_x combustors relative to standard designs for new applications were provided by three manufacturers for several turbines.[3,14,26] Based on information from the manufacturers, the performance and maintenance requirements for a low-NO_x combustor are expected to be the same as for a standard combustor, and so the only annual cost associated with low-NO_x combustors is the capital recovery. The capital recovery factor is 0.1315, assuming a life of 15 years and an interest rate of 10 percent.

Table 6-7

TABLE 6-7. COST-EFFECTIVENESS SUMMARY FOR DRY LOW-NO_x COMBUSTORS USING NATURAL GAS FUEL (1990 $)

Model plant [a]	GT model	Power output, MW	Annual operating hours	NO_x emissions [b]				NO_x removed, tons/yr	Incremental capital cost,$ [d]	Annual cost, $ [e]	Cost effectiveness, $/ton NO_x removed
				Uncontrolled NO_x		Controlled NO_x					
				ppmv [c]	Tons/yr	ppmv	Tons/yr				
CON-L-3.3-42	Centaur T4500	3.3	8,000	130	88.1	42.0	28.5	59.6	375,000	49,300	827
CON-L-4.0-42	Centaur 'H'	4.0	8,000	105	83.0	42.0	33.2	49.8	400,000	52,600	1,060
CON-L-4.5-42	Taurus	4.5	8,000	114	98.7	42.0	36.4	62.4	425,000	55,900	896
CON-L-8.8-42	Mars T12000	8.8	8,000	178	278	42.0	65.5	212	700,000	92,100	434
CON-L-10-42	Mars T14000	10.0	8,000	199	341	42.0	72.1	269	725,000	95,300	354
CON-L-3.3-25	Centaur T4500	3.3	8,000	130	88.1	25.0 [f]	16.9	71.2	375,000	49,300	693
CON-L-4.0-25	Centaur 'H'	4.0	8,000	105	83.0	25.0 [f]	19.8	63.2	400,000	52,600	832
CON-L-4.5-25	Taurus	4.5	8,000	114	98.7	25.0 [f]	21.7	77.1	425,000	55,900	725
CON-L-8.8-25	Mars T12000	8.8	8,000	178	278	25.0 [f]	39.0	239	700,000	92,100	386
CON-L-10-25	Mars T14000	10.0	8,000	199	341	25.0 [f]	42.9	299	725,000	95,300	319
CON-L-39-25	MS6000	39.0	8,000	220	1,480	25.0	168	1,310	1,400,000	184,000	140
CON-L-83-25	ABB GT11N	83.3	8,000	390	5,420	25.0	347	5,070	2,200,000	289,000	57.0
CON-L-85-25	MS7001E	84.7	8,000	154	2,180	25.0	353	1,830	2,140,000	281,000	154
CON-L-39-9	MS6000	39.0	8,000	220	1,480	9.00	60.6	1,420	1,400,000	184,000	130
CON-L-83-9	ABB GT11N	83.3	8,000	390	5,420	9.00	125	5,290	2,200,000	289,000	54.6
CON-L-85-9	MS7001E	84.7	8,000	154	2,180	9.00	127	2,050	2,140,000	281,000	137
PKR-L-3.3-42	Centaur T4500	3.3	2,000	130	22.0	42.0	7.12	14.9	375,000	49,300	3,310
PKR-L-4.0-42	Centaur 'H'	4.0	2,000	105	20.7	42.0	8.30	12.4	400,000	52,600	4,230
PKR-L-4.5-42	Taurus	4.5	2,000	114	24.7	42.0	9.09	15.6	425,000	55,900	3,590
PKR-L-8.8-42	Mars T12000	8.8	2,000	178	69.4	42.0	16.4	53.1	700,000	92,100	1,740
PKR-L-10-42	Mars T14000	10.0	2,000	199	85.4	42.0	18.0	67.3	725,000	95,300	1,420
PKR-L-3.3-25	Centaur T4500	3.3	2,000	130	22.0	25.0 [f]	4.24	17.8	375,000	49,300	2,770
PKR-L-4.0-25	Centaur 'H'	4.0	2,000	105	20.7	25.0 [f]	4.94	15.8	400,000	52,600	3,330
PKR-L-4.5-25	Taurus	4.5	2,000	114	24.7	25.0 [f]	5.41	19.3	425,000	55,900	2,900
PKR-L-8.8-25	Mars T12000	8.8	2,000	178	69.4	25.0 [f]	9.75	59.7	700,000	92,100	1,540
PKR-L-10-25	Mars T14000	10.0	2,000	199	85.4	25.0 [f]	10.7	74.6	725,000	95,300	1,280
PKR-L-39-25	MS6000	39.0	2,000	220	371	25.0	42.1	328	1,400,000	184,000	560
PKR-L-83-25	ABB GT11N	83.3	2,000	390	1,350	25.0	86.8	1,260	2,200,000	289,000	229
PKR-L-85-25	MS7001E	84.7	2,000	154	540	25.0	88.3	452	2,140,000	281,000	622
*PKR-L-39-9	MS6000	39.0	2,000	220	371	9.00	15.2	355	1,400,000	184,000	518
PKR-L-83-9	ABB GT11N	83.3	2,000	390	1,350	9.00	31.3	1,320	2,200,000	289,000	219
PKR-L-85-9	MS7001E	84.7	2,000	154	540	9.00	31.8	508	2,140,000	281,000	553

[a]Model plant legend: First entry: annual operating hours Second entry: control technique Third entry: power output, in MW Fourth entry: controlled NO_x level, ppmv at 15 percent O
CON - Continuous duty, 8,000 hours L - dry low-NO_x combustor
PKR - peaking/intermittent duty, 2,000 hours

For example, CON-L-3.3-42 designates that the model plant operates 8,000 hours per year, is fitted with a dry low-NO_x combustor, has a power output of 3.3 MW, and has a controlled NO_x level of 42 ppmv.

[b]Example NO_x emission calculations are shown in Appendix A.

[c]Referenced to 15 percent oxygen.

[d]Incremental capital costs were provided by the manufacturers.

presents the uncontrolled and controlled emission levels, the annual emission reductions, incremental costs for a low-NO_x combustor over a conventional design, and the cost effectiveness of low-NO_x combustors for all gas turbine models for which sufficient data were available. Cost-effectiveness figures were calculated for 8,000 and 2,000 hours of operation annually, using controlled NO_x emission levels of 42, 25, and 9 parts per million, by volume (ppmv), referenced to 15 percent oxygen, which are the achievable levels stated by the turbine manufacturers. The cost effectiveness varies according to the uncontrolled NO_x emission level for the conventional combustor design and the achievable controlled emission level for the low-NO_x design. For continuous-duty applications, cost effectiveness for a controlled NO_x emission level of 42 ppmv ranges from $353 to $1,060 per ton of NO_x removed. The cost-effectiveness range decreases to $57 to $832 per ton of NO_x removed for a controlled NO_x emission level of 25 ppmv and decreases further to $55 to $137 per ton of NO_x removed for a 9 ppmv control level. In all cases, the cost effectiveness increases as the operating hours decrease. In general, the cost effectiveness is higher for smaller gas turbines than for larger turbines due to the relatively higher capital cost per kW for low-NO_x combustors for smaller turbines.

The cost-effectiveness range is lower for low-NO_x combustors than for water or steam injection because the total annual costs are lower and, in some cases, the controlled emission levels are

also lower. According to two turbine manufacturers, retrofit costs are 40 to 60 percent greater than the incremental costs shown in Table 6-7 for new installations.[3,14]

c. SELECTIVE CATALYTIC REDUCTION

The costs for SCR for new installations were estimated for all model plants. Retrofit costs for SCR were not available but could be considerably higher than the costs shown for new installations, especially in applications where an existing heat recovery steam generator (HRSG) would have to be moved, modified, or replaced to accommodate the addition of a catalyst reactor.

To date, most gas turbine SCR applications use a base metal catalyst with an operating temperature range that requires cooling of the exhaust gas from the turbine. For this reason, SCR applications to date have been limited to combined cycle or cogeneration applications that include an HRSG, which serves to cool the exhaust gas to temperatures compatible with the catalyst. The introduction of high-temperature zeolite catalysts, however, makes it possible to install the catalyst directly downstream of the turbine, and therefore feasible to use SCR with simple-cycle applications as well as heat recovery applications. As discussed in Section 5.3.2, to date there is at least one gas turbine installation with a high-temperature zeolite catalyst installed downstream of the turbine and upstream of an HRSG. At present, no identified SCR systems are installed in simple-cycle gas turbine applications.

An overview of the procedures used to estimate capital and annual costs are described in Sections 6.3.1 and 6.3.2, respectively; a detailed cost algorithm is presented in Appendix B. The emission reduction and cost-effectiveness calculations are described in Section 6.3.3.

i. <u>Capital Costs</u>

Five documents in the technical literature contained SCR capital costs for 21 gas turbine facilities. Most of these documents presented costs that were obtained from vendors, but some may have also developed at least some costs based on their own experiences.[27-31] Most of the documents presented only the

total capital costs, not costs for individual components, and they did not provide complete descriptions of what the costs included. These costs were plotted on a graph of total capital costs versus gas turbine size. To this graph were added estimates of total installed costs for a high-temperature catalyst SCR system for installation upstream of the HRSG for four turbine installations ranging in size from 4.5 to 83 MW (6,030 to 111,000 hp). These high-temperature SCR system estimates include the catalyst reactor, air injection system for exhaust temperature control, ammonia storage and injection system, instrumentation, and continuous emission monitoring equipment. These SCR costs were estimated by the California Air Resources Board (CARB) in 1991 dollars and are based on NO_x emission levels of 42 ppmv into and 9 ppmv out of the SCR.[35] These estimated costs, shown in Appendix B, fit well within the range of costs from the 21 installations discussed above, and the equation of a line determined by linear regression adequately fits the data ($R^2 = 0.76$) for all 25 points. Based on this graph, the total capital cost for either a base-metal SCR system installed within the HRSG or a high-temperature zeolite catalyst SCR system installed directly downstream of the turbine can be calculated using the equation determined by the linear

TABLE 6-8. PROCEDURES FOR ESTIMATING CAPITAL AND ANNUAL COSTS FOR SCR CONTROL OF NO_X EMISSIONS FROM GAS TURBINES[a]

A. Total capital investment, $[b]	=	(49,700 x TMW) + 459,000
B. Direct annual costs, $/yr		
1. Operating labor[c]	=	(1.0 hr/8 hr-shift) x ($25.60/hr) x (H)
2. Supervisory labor	=	(0.15) x (operating labor)
3. Maintenance labor and materials	=	(1,250 x TMW) + 25,800
4. Catalyst replacement	=	(4,700 x TMW) + 37,200
5. Catalyst disposal[d]	=	(V) x ($15/$ft^3$) x (.2638)
6. Anhydrous ammonia[e]	=	(N) x ($360/ton)
7. Dilution steam[f]	=	(N) x (0.95/0.05) x (MW H_2O/MW NH_3) x ($6/1,000 lb steam) x (2,000 lb/ton)
8. Electricity[g]	=	N/A
9. Performance loss[h]	=	(0.005) x (TMW) x ($0.06/KWH) x (1,000 KW/MW) x (H)
10. Blower (if needed)	=	0.1 x (Performance Loss)
11. Production loss[i]	=	None
C. Indirect annual costs, $/yr		
1. Overhead	=	(0.6) x (all labor and maintenance material costs)
2. Property taxes, insurance, and administration	=	(0.04) x (total capital investment)
3. Capital recovery[j]	=	(0.13147) x [total capital investment - (catalyst replacement/0.2638)]

[a]All costs are in average 1990 dollars.

[b]TMW=turbine output in MW for each model plant.

[c]The annual operating hours are represented by the variable H. The labor rate of $25.60/hr is from Table 6-3.

[d]The catalyst volume in ft^3 is represented by the variable V. The catalyst volume for each model plant is estimated as V = (TMW) x (6,180 ft^3/83 MW).

[e]The ammonia requirement in tons is represented by the variable N and is calculated using a NH_3-to-NO_x molar ratio of 1.0.

The annual tonnage of NO_x is taken from the controlled levels shown in Tables 6-11 and 6-12.

[f]The ammonia is diluted with steam to 5 percent by volume before injection.

[g]The amount of electricity required for ammonia pumps and exhaust fans is not known, but is expected to be small. The electricity cost comprised less than 1 percent of the total annual cost estimated by the South Coast Air Quality Management District (SCAQMD) for SCR applied to a 1.1 MW turbine.

[h]Based on information from three sources, the backpressure from the SCR reduces turbine output by an average of about 0.9 percent.

[i]No production losses are estimated because it is assumed that all SCR maintenance, inspections, cleaning, etc. can be performed during the 760 hours of scheduled downtime per year.

[j]The capital recovery factor for the SCR is 0.13147, based on a 15-year equipment life and 10 percent interest rate. The catalyst is replaced every 5 years. The 0.2638 figure is the capital recovery factor for a 5-year equipment life and a 10 percent interest rate.

regression. This equation is shown in Table 6-8 and was used to calculate the total capital investment for SCR for each model plant shown in Tables 6-9 and 6-10.

TABLE 6-9. CAPITAL AND ANNUAL COSTS FOR SCR USED DOWNSTREAM OF WATER OR STEAM INJECTION (1990 $)

Model plant	GT model	Total capital investment, $[a]	Operating labor, $	Super-visory labor, $	Main-tenance labor & materials, $	Catalyst replace-ment, $	Catalyst disposal, $	Ammonia, $	Dilution steam, $	Perfor-mance loss, $	Blower (if needed), $	Over-head, $	Taxes, insurance & admin, $	Capital recovery, $	Total annual cost, $
CON-G-W-3.3	Centaur T4500	622,000	25,600	3,840	29,900	52,600	963	2,980	1,770	7,850	785	35,600	24,900	55,600	242,000
CON-G-W-4.0	501-KB5	658,000	25,600	3,840	30,800	56,000	1,180	3,570	2,130	9,600	960	36,100	26,300	58,600	255,000
CON-G-W-22.7	LM2500	1,590,000	25,600	3,840	54,100	144,000	6,680	14,700	8,740	54,400	5,440	50,100	63,600	137,000	568,000
CON-G-W-26.8	MS5001P	1,790,000	25,600	3,840	59,300	163,000	7,900	22,400	13,300	64,300	6,430	53,200	71,600	154,000	645,000
CON-G-W-83.3	ABB GT11N	4,600,000	25,600	3,840	130,000	429,000	24,500	29,600	17,600	200,000	20,000	95,700	184,000	391,000	1,550,000
CON-G-W-84.7	MS7001E	4,670,000	25,600	3,840	132,000	435,000	25,000	62,000	36,900	203,000	20,300	96,900	187,000	397,000	1,620,000
CON-G-S-4.0	501-KB5	658,000	25,600	3,840	30,800	56,000	1,180	3,570	2,130	9,600	960	36,100	26,300	58,600	255,000
CON-G-S-22.7	LM2500	1,590,000	25,600	3,840	54,100	144,000	6,680	7,110	4,240	54,400	5,440	50,100	63,600	137,000	556,000
CON-G-S-26.8	MS5001P	1,790,000	25,600	3,840	59,300	163,000	7,900	22,400	13,300	64,300	6,430	53,200	71,600	154,000	645,000
CON-G-S-34.4	LM5000	2,170,000	25,600	3,840	68,900	199,000	10,100	10,700	6,380	82,700	8,270	59,000	86,800	186,000	747,000
CON-G-S-83.3	ABB GT11N	4,600,000	25,600	3,840	130,000	429,000	24,500	61,000	36,300	200,000	20,000	95,700	184,000	391,000	1,600,000
CON-G-S-84.7	MS7001E	4,670,000	25,600	3,840	132,000	435,000	25,000	62,000	36,900	203,000	20,300	96,900	187,000	397,000	1,620,000
CON-G-S-161	MS7001F	8,460,000	25,600	3,840	227,000	794,000	47,400	108,000	64,200	386,000	38,600	154,000	338,000	717,000	2,900,000
CON-O-W-3.3	Centaur T4500	622,000	25,600	3,840	29,900	52,600	963	3,890	2,320	7,850	785	35,600	24,900	55,600	244,000
CON-O-W-26.3	MS5001P	1,770,000	25,600	3,840	58,700	161,000	7,750	32,400	19,300	63,100	6,310	52,900	70,800	152,000	654,000
CON-O-W-83.3	MS7001E	4,600,000	25,600	3,840	130,000	429,000	24,500	90,000	53,800	200,000	20,000	95,700	184,000	391,000	1,650,000
PKR-G-W-3.3	Centaur T4500	622,000	6,400	960	7,470	13,100	241	740	440	1,960	196	8,900	24,900	75,300	141,000
PKR-G-W-26.8	MS5001P	1,790,000	6,400	960	14,800	40,800	1,970	5,600	3,330	16,100	1,610	13,300	71,600	215,000	391,000
PKR-G-W-84.7	MS7001E	4,670,000	6,400	960	32,900	109,000	6,240	15,500	9,240	50,800	5,080	24,200	187,000	560,000	1,010,000
PKR-O-W-3.3	Centaur T4500	622,000	6,400	960	7,470	13,100	241	970	580	1,960	196	8,900	24,900	75,300	141,000
PKR-O-W-26.3	MS5001P	1,770,000	6,400	960	14,700	40,200	1,940	8,100	4,830	15,800	1,580	13,200	70,800	213,000	392,000
PKR-O-W-84.7	MS7001E	4,600,000	6,400	960	32,500	107,000	6,140	22,500	13,440	50,000	5,000	23,900	184,000	552,000	1,000,000
STD-O-W-1.1	Saturn T1500	515,000	3,200	480	3,400	5,310	41.6	185	158	339	33.9	4,250	20,600	65,100	103,000
STD-O-E-28.0	TPM FT4	1,850,000	3,200	480	60,800	21,100	1,030	3,180	2,960	8,400	840	38,700	74,000	233,000	448,000

[a]Costs shown are for SCR systems used downstream of gas turbines with wet injection to achieve controlled NO_x emission levels at the inlet to the SCR as shown in Table 6-6.

TABLE 6-10. CAPITAL AND ANNUAL COSTS FOR SCR USED DOWNSTREAM OF LOW-NO_x COMBUSTION

Model plant [a]	GT model	Total capital invest., $ [b]	Operating labor,$	Super-visory labor, $	Main-tenance labor & materials, $	Catalyst replacement, $	Catalyst disposal, $	Ammonia,$	Dilution steam, $	Perfor-mance loss, $	Blower (if needed), $	Over-head, $	Taxes, insurance & admin., $	Capital recovery, $	Total annual cost, $
CON-L-3.3-42	Centaur T4500	622,000	25,600	3,840	29,900	52,700	970	2,980	1,770	7,920	790	35,600	24,900	55,500	242,000
CON-L-4.0-42	Centaur 'H'	658,000	25,600	3,840	30,800	56,000	1,180	3,470	2,070	9,600	960	36,100	26,300	58,600	255,000
CON-L-4.5-42	Taurus	683,000	25,600	3,840	31,400	58,400	1,330	3,800	2,270	10,800	1,080	36,500	27,300	60,700	263,000
CON-L-8.8-42	Mars T12000	896,000	25,600	3,840	36,800	78,600	2,590	6,850	4,080	21,100	2,110	39,700	35,800	78,600	336,000
CON-L-10-42	Mars T14000	956,000	25,600	3,840	38,300	84,200	2,950	7,530	4,490	24,000	2,400	40,600	38,200	83,700	356,000
CON-L-3.3-25	Centaur T4500	622,000	25,600	3,840	29,900	52,700	970	1,440	860	7,920	790	35,600	24,900	55,500	240,000
CON-L-4.0-25	Centaur 'H'	658,000	25,600	3,840	30,800	56,000	1,180	1,680	1,000	9,600	960	36,100	26,300	58,600	252,000
CON-L-4.5-25	Taurus	683,000	25,600	3,840	31,400	58,400	1,330	1,840	1,100	10,800	1,080	36,500	27,300	60,700	260,000
CON-L-8.8-25	Mars T12000	896,000	25,600	3,840	36,800	78,600	2,590	3,320	1,980	21,100	2,110	39,700	35,800	78,600	330,000
CON-L-10-25	Mars T14000	956,000	25,600	3,840	38,300	84,200	2,950	3,650	2,180	24,000	2,400	40,600	38,200	83,700	350,000
CON-L-39-25	MS6000	2,400,000	25,600	3,840	74,600	221,000	11,490	14,300	8,550	93,600	9,360	62,400	96,000	205,000	826,000
CON-L-83-25	ABB GT11N	4,600,000	25,600	3,840	130,000	429,000	24,540	29,600	17,600	200,000	20,000	95,700	184,000	391,000	1,550,000
CON-L-85-25	MS7001E	4,670,000	25,600	3,840	132,000	435,000	24,960	30,100	17,900	203,000	20,300	96,900	186,800	397,000	1,570,000
PKR-L-3.3-42	Centaur T4500	622,000	6,400	960	7,480	55,100	2,870	740	440	1,980	200	8,900	24,900	54,300	164,000
PKR-L-4.0-42	Centaur 'H'	658,000	6,400	960	7,700	107,000	6,140	870	520	2,400	240	9,000	26,300	33,200	201,000
PKR-L-4.5-42	Taurus	683,000	6,400	960	7,860	109,000	6,240	950	570	2,700	270	9,100	27,300	35,500	207,000
PKR-L-8.8-42	Mars T12000	896,000	6,400	960	9,200	9,300	0	1,710	1,020	5,280	530	9,900	35,800	113,000	193,000
PKR-L-10-42	Mars T14000	956,000	6,400	960	9,580	13,200	240	1,880	1,120	6,000	600	10,200	38,200	119,000	207,000
PKR-L-3.3-25	Centaur T4500	623,000	6,400	960	7,480	14,600	330	360	210	1,980	200	8,900	24,900	74,600	141,000
PKR-L-4.0-25	Centaur 'H'	658,000	6,400	960	7,700	19,600	650	420	250	2,400	240	9,000	26,300	76,800	151,000
PKR-L-4.5-25	Taurus	683,000	6,400	960	7,860	21,100	740	460	270	2,700	270	9,100	27,300	79,300	156,000
PKR-L-8.8-25	Mars T12000	896,000	6,400	960	9,200	9,300	0	830	490	5,280	530	9,900	35,800	113,000	192,000
PKR-L-10-25	Mars T14000	956,000	6,400	960	9,580	13,200	240	910	540	6,000	600	10,200	38,200	119,000	206,000
PKR-L-39-25	MS6000	2,400,000	6,400	960	18,600	14,000	290	3,590	2,140	23,400	2,340	15,600	96,000	309,000	492,000
PKR-L-83-25	ABB GT11N	4,600,000	6,400	960	32,500	14,600	330	7,390	4,410	50,000	5,000	23,900	184,000	598,000	927,000
PKR-L-85-25	MS7001E	4,670,000	6,400	960	32,900	19,600	650	7,520	4,480	50,800	5,080	24,200	186,800	604,000	943,000

[a] See Table 6-7 for model plant legend.

[b] Costs shown are for SCR systems used downstream of gas turbines with dry low-NO_x combustion to achieve controlled NO_x emission levels at the inlet to the SCR as shown in Table 6-7.

ii. Annual Costs

Total annual costs for SCR control were developed following standard EPA procedures described in the OAQPS Control Cost Manual for other types of add-on air pollution control devices (APCD's). Information about annual costs was obtained from the same sources that provided capital costs.[27-31] Total annual costs consist of direct and indirect costs; parameters that make up these categories and the equations for estimating the costs are

presented in Table 6-8 and are discussed below. The annual costs are shown in Tables 6-9 and 6-10 for injection and dry low-NO_x combustion, respectively, for each of the model plants.

(1) Operating and Supervisory Labor. Information about operating labor requirements was unavailable. Most facilities have fully automated controls and monitoring/recording equipment, which minimizes operator attention. Therefore, it was assumed that 1 hr of operator attention would be required during an 8-hr shift, regardless of turbine size. This operating labor requirement is at the low end of the range recommended in the OAQPS Control Cost Manual for other types of APCD's.[7] Operator wage rates were estimated to be $25.60/hr in 1990, based on escalating the costs presented in Reference 2 by 5 percent per year to account for inflation. Supervisory labor costs were estimated to be 15 percent of the operating labor costs, consistent with the OAQPS Control Cost Manual.

(2) Maintenance Labor and Materials. Combined maintenance labor and materials costs for 14 facilities were obtained from four articles, but almost half of the data (6 facilities) were provided by one source.[27-30] The costs were escalated to 1990 dollars assuming an inflation rate of 5 percent per year. All of the data are for facilities that burn natural gas. Provided that ammonium salt formation is avoided by limiting ammonia slip and sulfur content, the cost for operation with natural gas should also apply for distillate oil fuel.[32] Therefore, it was assumed that the cost data also apply to SCR control for turbines that fire distillate oil fuel. The costs were plotted versus the turbine size, and least-squares linear regression was used to determine the equation of the line through the data (see Appendix B). This equation, shown in Table 6-8, was used to estimate the maintenance labor and materials costs shown in Table 6-9 for the model plants.

(3) Catalyst Replacement. Replacement costs were obtained for nine gas turbine facilities, and combined replacement and disposal costs were obtained for another six gas turbine facilities.[27-30] The disposal costs were estimated for the six

facilities as described below and in Appendix B. The replacement costs for these six facilities were then estimated by subtracting the estimated disposal costs from the combined costs. A catalyst life of 5 years was used. All replacement costs were escalated to 1990 dollars assuming a 5 percent annual inflation rate.

The estimated 1990 replacement costs were plotted versus the turbine size, and least-squares linear regression was used to determine the equation of the line through the data (see Appendix B). This equation is shown in Table 6-8 and was used to estimate the catalyst replacement costs shown in Table 6-9 for the model plants.

(4) Catalyst Disposal. Catalyst disposal costs were estimated based on a unit disposal cost of $\$15/ft^3$, which was obtained from a zeolite catalyst vendor.[32] This cost was used for each model plant, but the disposal cost may in fact be higher for catalysts that contain heavy metals and are classified as hazardous wastes. The catalyst volume for each model plant was estimated based on information about the catalyst volume for one facility and the assumption that there is a direct relationship between the catalyst volume and the turbine output (i.e., the design space velocity is the same regardless of the SCR size). At one facility, 175 m^3 (6,180 ft^3) of catalyst is used in the SCR with an 83 MW (111,000 hp) turbine.[33] The disposal cost for this catalyst would be \$92,700, using a cost of $\$15/ft^3$.

(5) Ammonia. The annual ammonia (NH_3) requirement is calculated from the annual NO_x reduction achieved by the SCR system. Based on an NH_3/NO_x molar ratio of 1.0, the annual ammonia requirement, in tons, would equal the annual NO_x reduction, in tons, multiplied by the ratio of the molecular weights for NH_3 and NO_x. Anhydrous ammonia with a unit cost of \$360/ton was used.[34,35] The equation to calculate the annual cost for ammonia is shown in Table 6-8.

(6) Dilution Steam. As indicated in Section 5.3.1, steam is used to dilute the ammonia to about 5 percent by volume before injection into the HRSG. According to the OAQPS Control Cost

Manual, the cost to produce steam, or to purchase it, is about $6/1,000 lb.

(7) Electricity. Electricity requirements to operate such equipment as ammonia pumps and ventilation fans is believed to be small. For one facility, the cost of electricity to operate these components was estimated to make up less than 1 percent of the total annual cost, but it is not clear that the number and size of the fans and pumps represent a typical installation.[27] This cost for electricity is expected to be minor, however, for all installations and was not included in this analysis.

For high-temperature catalysts installed upstream of the HRSG, a blower may be required to inject ambient air into the exhaust to regulate the temperature and avoid temperature excursions above the catalyst design temperature range. The cost to operate the blower is calculated to be 10 percent of the fuel penalty.[35]

(8) Performance Loss. The performance loss due to backpressure from the SCR is approximately 0.5 percent of the turbine's design output.[34-36] To make up for this lost output, it was assumed that electricity would have to be purchased at a cost of $0.06/kWH, as indicated in Table 6-3.

(9) Production Loss. No costs for production losses were included in this analysis. It was assumed that scheduled inspections, cleaning, and other maintenance will coincide with the 760 hr/yr of expected or scheduled downtime. It should be recognized that adding the SCR system increases the overall system complexity and the probability of unscheduled outages. This factor should be taken into account when considering the addition of an SCR system.

(10) Overhead. Standard EPA procedures for estimating annual control costs include overhead costs that are equal to 60 percent of all labor and maintenance material costs.

(11) Property Taxes, Insurance, and Administration. According to standard EPA procedures for estimating annual control costs, property taxes, insurance, and administration

costs are equal to 4 percent of the total capital investment for the control system.

(12) Capital Recovery. The CRF for SCR was estimated to be 0.13147 based on the assumption that the equipment life is 15 years and the interest rate is 10 percent.

iii. Cost Effectiveness for SCR

As indicated in Section 5.4, virtually all gas turbine installations using SCR to reduce NO_x emissions also incorporate wet injection or low-NO_x combustors. The NO_x emission levels into the SCR, therefore, were in all cases taken to be equal to the controlled NO_x emission levels shown for these control techniques in Tables 6-6 and 6-7. The most common controlled NO_x emission limit for gas-fired SCR applications is 9 ppmv, referenced to 15 percent oxygen. The capital costs used in this analysis are expected to correspond to SCR systems sized to reduce controlled NO_x emissions ranging from 25 to 42 ppmv from gas-fired turbines to a controlled level of approximately 9 ppmv downstream of the SCR. Based on the controlled NO_x emission limits established by the Northeast States for Coordinated Air Use Management (NESCAUM), shown in Table 5-3, these SCR systems would reduce NO_x emissions to 18 ppmv for oil-fired applications. Cost-effectiveness figures for SCR in this analysis are therefore calculated based on controlled NO_x emission levels of 9 and 18 ppmv, corrected to 15 percent oxygen, for gas- and oil-fired SCR model plants, respectively.

Cost effectiveness for SCR used downstream of wet injection or dry low-NO_x combustion is shown in Tables 6-11

TABLE 6-11. COST-EFFECTIVENESS SUMMARY FOR SCR USED DOWNSTREAM OF GAS TURBINES WIT H WET INJECTION (1990 $)

Model plant	GT model	Turbine output, MW	NO_x emissions[a]				Total NO_x removed, tons/yr	Total annual cost, $[c]	Cost effective-ness, $/ton
			Inlet to SCR		Downstream of SCR				
			ppmv[b]	tons/yr	ppmv	[b] tons/yr			
CON-G-W-3.3	Centaur T4500	3.3	42	28.5	9.0	6.10	22.4	242,000	10,800
CON-G-W-4.0	501-KB5	4.0	42	34.2	9.0	7.32	26.8	255,000	9,500
CON-G-W-22.7	LM2500	22.7	42	140	9.0	30.0	110	568,000	5,160
CON-G-W-26.8	MS5001P	26.8	42	214	9.0	45.8	168	645,000	3,840
CON-G-W-83.3	ABB GT11N	83.3	25	347	9.0	125	222	1,550,000	6,980
CON-G-W-84.7	MS7001E	84.7	42	593	9.0	127	466	1,620,000	3,480
CON-G-S-4.0	501-KB5	4.0	42	34.2	9.0	7.32	26.8	255,000	9,500
CON-G-S-22.7	LM2500	22.7	25	83.5	9.0	30.0	53.4	556,000	10,400
CON-G-S-26.8	MS5001P	26.8	42	214	9.0	45.8	168	645,000	3,840
CON-G-S-34.4	LM5000	34.4	25	126	9.0	45.2	80.4	747,000	9,290
CON-G-S-83.3	ABB GT11N	83.3	42	583	9.0	125	458	1,600,000	3,490
CON-G-S-84.7	MS7001E	84.7	42	593	9.0	127	466	1,620,000	3,480
CON-G-S-161	MS7001F	161	42	1,030	9.0	221	809	2,900,000	3,580
CON-O-W-3.3	Centaur T4500	3.3	60	41.8	18.0	12.5	29.3	244,000	8,340
CON-O-W-26.3	MS5001P	26.3	65	337	18.0	93.3	244	654,000	2,690
CON-O-W-83.3	MS7001E	83.3	65	938	18.0	260	678	1,650,000	2,430
PKR-G-W-3.3	Centaur T4500	3.3	42	7.12	9.0	1.52	5.59	141,000	25,200
PKR-G-W-26.8	MS5001P	26.8	42	53.5	9.0	11.5	42.0	391,000	9,310
PKR-G-W-84.7	MS7001E	84.7	42	148	9.0	31.8	116	1,010,000	8,670
PKR-O-W-3.3	Centaur T4500	3.3	60	10.5	18.0	3.14	7.32	141,000	19,300
PKR-O-W-26.3	MS5001P	26.3	65	84.2	18.0	23.3	60.9	392,000	6,440
PKR-O-W-84.7	MS7001E	84.7	65	234	18.0	64.9	169	1,000,000	5,900
STD-O-W-1.1	Saturn T1500	1.1	60	1.99	18.0	0.60	1.39	103,000	74,000
STD-O-E-28.0	TPM FT4	28.0	50	37.3	18.0	13.4	23.9	448,000	18,800

[a]Example NO_x emission calculations are shown in Appendix A.
[b]Referenced to 15 percent oxygen.
[c]From Table 6-9.

TABLE 6-12. COST-EFFECTIVENESS SUMMARY FOR SCR USED DOWNSTREAM OF DRY LOW-NO_x COMBUSTION (1990 $)

Model plant[a]	GT model	Turbine output, MW	NO_x emissions[b]						Total NO_x removed, tons/yr	Total annual cost, $[d]	Cost effectiveness, $/ton
			Uncontrolled		Inlet to SCR		Downstream of SCR				
			ppmv[c]	tons/yr	ppmv	tons/yr	ppmv	tons/yr			
CON-L-3.3-42	Centaur T4500	3.3	130	88.1	42	28.5	9.0	6.1	22.4	242,000	10,800
CON-L-4.0-42	Centaur 'H'	4.0	105	83.0	42	33.2	9.0	7.1	26.1	255,000	9,780
CON-L-4.5-42	Taurus	4.5	114	98.7	42	36.4	9.0	7.8	28.6	263,000	9,200
CON-L-8.8-42	Mars T12000	8.8	178	278	42	65.5	9.0	14.0	51.5	336,000	6,530
CON-L-10-42	Mars T14000	10.0	199	341	42	72.1	9.0	15.4	56.6	356,000	6,290
CON-L-3.3-25	Centaur T4500	3.3	130	88.1	25	16.9	9.0	6.1	10.8	240,000	22,100
CON-L-4.0-25	Centaur 'H'	4.0	105	83.0	25	19.8	9.0	7.1	12.6	252,000	19,900
CON-L-4.5-25	Taurus	4.5	114	98.7	25	21.7	9.0	7.8	13.9	260,000	18,800
CON-L-8.8-25	Mars T12000	8.8	178	278	25	39.0	9.0	14.0	25.0	330,000	13,200
CON-L-10-25	Mars T14000	10.0	199	341	25	42.9	9.0	15.4	27.5	350,000	12,800
CON-L-39-25	MS6000	39.0	220	1,480	25	168	9.0	61	108	826,000	7,660
CON-L-83-25	ABB GT11N	83.3	390	5,420	25	347	9.0	125	222	1,550,000	6,970
CON-L-85-25	MS7001E	84.7	154	2,180	25	353	9.0	127	226	1,570,000	6,940
PKR-L-3.3-42	Centaur T4500	3.3	130	22.0	42	7.12	9.0	1.52	5.6	164,000	29,300
PKR-L-4.0-42	Centaur 'H'	4.0	105	20.7	42	8.30	9.0	1.78	6.5	201,000	30,800
PKR-L-4.5-42	Taurus	4.5	114	24.7	42	9.09	9.0	1.95	7.1	207,000	29,000
PKR-L-8.8-42	Mars T12000	8.8	178	69.4	42	16.4	9.0	3.5	12.9	193,000	15,000
PKR-L-10-42	Mars T14000	10.0	199	85.4	42	18.0	9.0	3.9	14.2	207,000	14,600
PKR-L-3.3-25	Centaur T4500	3.3	130	22.0	25	4.24	9.0	1.52	2.7	141,000	52,000
PKR-L-4.0-25	Centaur 'H'	4.0	105	20.7	25	4.94	9.0	1.78	3.2	151,000	47,800
PKR-L-4.5-25	Taurus	4.5	114	24.7	25	5.41	9.0	1.95	3.5	156,000	45,000
PKR-L-8.8-25	Mars T12000	8.8	178	69.4	25	9.75	9.0	3.51	6.2	192,000	30,800
PKR-L-10-25	Mars T14000	10.0	199	85.4	25	10.7	9.0	3.9	6.9	206,000	30,000
PKR-L-39-25	MS6000	39.0	220	371	25	42.1	9.0	15.2	26.9	492,000	18,300
PKR-L-83-25	ABB GT11N	83.3	390	1,350	25	86.8	9.0	31.3	55.6	927,000	16,700
PKR-L-85-25	MS7001E	84.7	154	540	25	88.3	9.0	31.8	56.5	943,000	16,700

[a]See Table 6-7 for model plant legend.

[b]Example NO_x emission calculations are shown in Appendix A.

[c]Referenced to 15 percent oxygen.

[d]From Table 6-10.

and 6-12, respectively. For continuous-duty, natural gas-fired

model plants using water or steam injection,the cost effectiveness for SCR ranges from approximately $3,500 to $10,800 per ton of NO_x removed.

The cost-effectiveness range for SCR installed downstream of continuous-duty, natural gas-fired turbines from 3 to 10 MW (4,000 to 13,400 hp) using dry low-NO_x combustion is $6,290 to $10,800 per ton of NO_x removed for an inlet NO_x emission level of 42 ppmv. The cost-effectiveness range for SCR increases for an

inlet NO_x emission level of 25 ppmv due to the lower NO_x reduction efficiency. For an inlet NO_x level of 25 ppmv, the cost effectiveness ranges from $12,800 to $22,100 per ton of NO_x removed for 3 to 10 MW (4,000 to 13,400 hp) turbines and decreases to $6,940 to $7,660 per ton of NO_x removed for larger turbines ranging from 39 to 85 MW (52,300 to 114,000 hp). As these ranges indicate, the cost effectiveness for SCR is affected by the inlet NO_x emission level and not the type of combustion control technique used for the turbine. The cost effectiveness for continuous-duty, oil-fired model plants ranges from approximately $2,450 to $8,350 per ton of NO_x removed. The SCR cost-effectiveness range for oil-fired applications is lower than that for gas-fired installations in this cost analysis because the same capital costs were used for both fuels (capital costs were not available for applications using only distillate oil fuel). The percent NO_x reduction for oil-fired applications is higher, so the resulting cost-effectiveness figures for oil-fired applications are lower. It should be noted that this higher NO_x reduction for oil-fired applications may require a larger catalyst reactor, at a higher capital cost. As a result, the cost-effectiveness figures may actually be higher than those shown in Table 6-11 for oil-fired applications.

The cost-effectiveness figures are higher for smaller gas turbines because the fixed capital costs associated with the installation of an SCR system have the greatest impact on smaller gas turbines. Cost-effectiveness figures increase as annual operating hours decrease. For turbines operating 2,000 hours per year, cost-effectiveness figures are more than double those for continuous-duty model plants, and they increase even further for model plants operating 1,000 hr/yr.

Because virtually all SCR systems are installed downstream of controlled gas turbines, combined cost-effectiveness figures for wet injection plus SCR and also dry low-NO_x combustion plus SCR have been calculated and are shown in Tables 6-13

TABLE 6-13. COMBINED COST-EFFECTIVENESS SUMMARY FOR WET INJECTION PLUS SCR (1990 $)

Model plant	GT model	Turbine output MW	NO_x emissions[a]						Total NO_x removed, tons/yr[c]	Total annual cost, $[c]	Cost effectiveness, $/ton[c]
			Uncontrolled		Inlet to SCR		Downstream of SCR				
			ppmv[b]	tons/yr	ppmv	tons/yr[b]	ppmv	tons/yr[b]			
CON-G-W-3.3	Centaur T4500	3.3	130	88.1	42	28.5	9.0	6.10	82.0	366,000	4,460
CON-G-W-4.0	501-KB5	4.0	155	126	42	34.2	9.0	7.32	119	417,000	3,510
CON-G-W-22.7	LM2500	22.7	174	581	42	140	9.0	30	551	1,000,000	1,820
CON-G-W-26.8	MS5001P	26.8	142	723	42	214	9.0	46	677	1,220,000	1,800
CON-G-W-83.3	ABB GT11N	83.3	390	5,410	25	347	9.0	125	5,290	4,460,000	843
CON-G-W-84.7	MS7001E	84.7	154	2,170	42	593	9.0	127	2,040	3,100,000	1,520
CON-G-S-4.0	501-KB5	4.0	155	126	42	34.2	9.0	7.32	119	423,000	3,560
CON-G-S-22.7	LM2500	22.7	174	581	25	83.5	9.0	30.0	551	977,000	1,770
CON-G-S-26.8	MS5001P	26.8	142	723	42	214	9.0	45.8	677	1,130,000	1,670
CON-G-S-83.3	LM5000	34.4	185	930	25	126	9.0	45.2	884	1,440,000	1,630
CON-G-S-84.7	ABB GT11N	83.3	390	5,410	42	583	9.0	125	5,290	3,410,000	645
CON-G-S-84.7	MS7001E	84.7	154	2,170	42	593	9.0	127	2,040	2,780,000	1,360
CON-G-S-161	MS7001F	161	210	5,150	42	1,030	9.0	220	4,930	4,870,000	988
CON-O-W-3.3	Centaur T4500	3.3	179	125	60	42	18.0	12.5	112	387,000	3,450
CON-O-W-26.3	MS5001P	26.3	211	1,090	65	337	18.0	93.3	997	1,410,000	1,410
CON-O-W-83.3	MS7001E	83.3	228	3,290	65	938	18.0	260	3,030	3,230,000	1,070
PKR-G-W-3.3	Centaur T4500	3.3	130	22.0	42	7.1	9.0	1.5	20.5	222,000	10,800
PKR-G-W-26.8	MS5001P	26.8	142	181	42	53.5	9.0	11.5	169	690,000	4,080
PKR-G-W-84.7	MS7001E	84.7	154	543	42	148	9.0	31.8	512	1,710,000	3,340
PKR-O-W-3.3	Centaur T4500	3.3	179	31.2	60	10	18.0	3.14	28.1	228,000	8,130
PKR-O-W-26.3	MS5001P	26.3	211	273	65	84	18.0	23.3	250	751,000	3,000
PKR-O-W-84.7	MS7001E	84.7	228	822	65	234	18.0	64.9	757	1,710,000	2,260
STD-O-W-1.1	Saturn T1500	1.1	150	4.97 122	60	1.99	18.0	0.60	4.4	152,000	34,700
STD-O-E-28.0	TPM FT4	28.0	150		50	37.3	18.0	13.4	109	604,000	5,563

[a]Example NO_x emission calculations are shown in Appendix A.

[b]Referenced to 15 percent oxygen.

[c]Total for both wet injection plus SCR control techniques.

TABLE 6-14. COMBINED COST-EFFECTIVENESS SUMMARY FOR DRY LOW-NOx COMBUSTION PLUS SCR (1990 $)

Model plant	GT model	Turbine output MW	Annual operating hours	NO_x emissions[a]						Total NO_x removed, tons/yr[c]	Total annual cost, $[c]	Cost effectiveness, $/ton
				Uncontrolled		Inlet to SCR		Downstream of SCR				
				ppmv[b]	tons/yr	ppmv	tons/yr[b]	ppmv	tons/yr[b]			
CON-L-3.3-42	Centaur T4500	3.3	8,000	130	88.1	42	28.5	9.0	6.1	82.0	291,000	3,550
CON-L-4.0-42	Centaur 'H'	4.0	8,000	105	83.0	42	33.2	9.0	7.1	75.8	308,000	4,060
CON-L-4.5-42	Taurus	4.5	8,000	114	98.7	42	36.4	9.0	7.8	90.9	319,000	3,510
CON-L-8.8-42	Mars T12000	8.8	8,000	178	278	42	65.5	9.0	14.0	264	428,000	1,620
CON-L-10-42	Mars T14000	10.0	8,000	199	341	42	72.1	9.0	15.4	326	451,000	1,380
CON-L-3.3-25	Centaur T4500	3.3	8,000	130	88.1	25	16.9	9.0	6.1	82.0	289,000	3,520
CON-L-4.0-25	Centaur 'H'	4.0	8,000	105	83.0	25	19.8	9.0	7.1	75.8	305,000	4,020
CON-L-4.5-25	Taurus	4.5	8,000	114	98.7	25	21.7	9.0	7.8	90.9	316,000	3,470
CON-L-8.8-25	Mars T12000	8.8	8,000	178	278	25	39.0	9.0	14.0	264	422,000	1,600
CON-L-10-25	Mars T14000	10.0	8,000	199	341	25	42.9	9.0	15.4	326	445,000	1,370
CON-L-39-25	MS6000	39.0	8,000	220	1,480	25	168	9.0	60.6	1,420	1,010,000	710
CON-L-83-25	ABB GT11N	83.3	8,000	390	5,420	25	347	9.0	125	5,290	1,840,000	348
CON-L-85-25	MS7001E	84.7	8,000	154	2,180	25	353	9.0	127	2,050	1,850,000	902
PKR-L-3.3-42	Centaur T4500	3.3	2,000	130	22.0	42	7.1	9.0	1.5	20.5	213,000	10,400
PKR-L-4.0-42	Centaur 'H'	4.0	2,000	105	20.7	42	8.3	9.0	1.8	19.0	254,000	13,400
PKR-L-4.5-42	Taurus	4.5	2,000	114	24.7	42	9.1	9.0	1.9	22.7	263,000	11,600
PKR-L-8.8-42	Mars T12000	8.8	2,000	178	69.4	42	16.4	9.0	3.5	65.9	285,000	4,320
PKR-L-10-42	Mars T14000	10.0	2,000	199	85.4	42	18.0	9.0	3.9	81.5	302,000	3,710
PKR-L-3.3-25	Centaur T4500	3.3	2,000	130	22.0	25	4.2	9.0	1.5	20.5	190,000	9,300
PKR-L-4.0-25	Centaur 'H'	4.0	2,000	105	20.7	25	4.9	9.0	1.8	19.0	204,000	10,800
PKR-L-4.5-25	Taurus	4.5	2,000	114	24.7	25	5.4	9.0	1.9	22.7	212,000	9,300
PKR-L-8.8-25	Mars T12000	8.8	2,000	178	69.4	25	9.8	9.0	3.5	65.9	284,000	4,300
PKR-L-10-25	Mars T14000	10.0	2,000	199	85.4	25	10.7	9.0	3.9	81.5	301,000	3,700
PKR-L-39-25	MS6000	39.0	2,000	220	371	25	42.1	9.0	15.2	355	680,000	1,910
PKR-L-83-25	ABB GT11N	83.3	2,000	390	1,350	25	86.8	9.0	31.3	1,320	1,220,000	924
PKR-L-85-25	MS7001E	84.7	2,000	154	540	25	88.3	9.0	31.8	508	1,220,000	2,400

[a]Example NO_x emission calculations are shown in Appendix A.

[b]Referenced to 15 percent oxygen.

[c]Total for both dry low-NO_x combustion plus SCR control techniques.

and 6-14, respectively. These combined cost-effectiveness

figures are calculated by dividing the sum of the total annual costs by the

sum of the annual reduction of NO_x emissions for the combined emission control techniques. For continuous-duty, natural gas-fired model plants, the combined cost-effectiveness figures for wet injection plus SCR range from approximately $650 to $4,500 per ton of NO_x removed. For continuous-duty, oil-fired model plants, the combined cost effectiveness ranges from approximately $1,100 to $3,550 per ton of NO_x removed. The combined cost-effectiveness figures for dry low-NO_x combustion plus SCR for continuous-duty, natural gas-fired model plants range from approximately $350 to $3,550 per ton of NO_x removed.

The combined cost-effectiveness figures increase with decreasing turbine size and annual operating hours. Data were not available to quantify the wet injection requirements and controlled emissions levels for oil-fired turbines with low-NO_x combustors, so cost-effectiveness figures were not tabulated for this control scenario.

d. OFFSHORE TURBINES

The only available information about the cost of NO_x controls for offshore gas turbines was presented in a report prepared for the Santa Barbara County Air Pollution Control District (SBCAPCD) in California.[37] The performance and cost of about 20 NO_x control techniques for a 2.8 MW (3,750 hp) turbine were described in the report. Wet injection and SCR were included in the analysis; low-NO_x combustors were not. The costs from the report are presented in Table 6-15

TABLE 6-15. PROJECTED WET INJECTION AND SCR COSTS FOR AN OFFSHORE GAS TURBINE[a]

	Wet injection costs	SCR costs
Capital cost, $	70,000	585,000
Annual costs, $/yr		
Ammonia	N/A[b]	3,050[c]
Catalyst replacement	N/A	28,000
Operating and maintenance[d]	24,600	18,000
Fuel penalty[e]	10,500	5,000
Capital recovery[f]	14,000	117,000
Total annual costs, $/yr	49,100	171,000

[a]Costs are for a 2.8 MW gas turbine and are obtained from Reference 37.
[b]N/A = Not applicable.
[c]Ammonia cost is based on $150/ton and 0.4 lb NH_3/lb NO_X.
[d]Operating and maintenance cost for SCR is estimated as 3 percent of the total capital investment.
[e]Fuel penalty is estimated as 2 percent of the annual fuel consumption for wet injection and 1 percent for SCR.
[f]Capital recovery is estimated based on an equipment life of 8 years and an interest rate of 13 percent.

without adjustment because there is insufficient cost information to know what adjustments need to be made. Additionally, insufficient information is available to scale up these costs for larger turbines. The water and steam injection costs and SCR costs for offshore applications are discussed in Sections 6.4.1 and 6.4.2, respectively.

i. Wet Injection

The report prepared for SBCAPCD assumed water injection costs are the same as steam injection costs. The report did not describe the components in the capital cost analysis for these injection systems, but the results are much lower than those that

would be estimated by the procedures described in Section 6.1.1 of this report. The authors may have assumed that the engine-mounted injection equipment cost was included in the turbine capital cost and that a less rigorous water treatment process is installed. Annual costs are also much lower than those that would be estimated by the procedures described in Section 6.1.2 of this report. There are at least three reasons for the difference: (1) the low capital cost leads to a low CRF, even though the turbine life was assumed to be only 8 years; (2) overhead costs and taxes, insurance, and administration costs are not considered; and (3) the capacity factor is only 50 percent (i.e., about 4,400 hr/yr, vs. 8,000 hr/yr, as in Section 6.1.2). The turbine life was only 8 years, which may correspond to a typical service life of an offshore platform.

ii. Selective Catalytic Reduction

The total capital costs presented in the report for SBCAPCD are similar to those that would be estimated by the procedures in Section 6.2.1 of this report. However, it appears that $150,000 of the total in Reference 37 is for structural modifications to the platform and $75,000 is for retrofit installation. When the difference in the load factor is taken into account, some of the annual costs are similar to those that would be estimated by the procedures in Section 6.2.2 for a similarly sized turbine. The catalyst replacement cost, however, is much lower; neither the type of catalyst nor the replacement frequency were identified. Ammonia costs are lower because the uncontrolled NO_x emission level was assumed to be 110 ppmv instead of 150 ppmv and because a unit cost of $150/ton was used instead of $400/ton. The reference does not indicate whether or not catalyst disposal, overhead, taxes, freight, and administration costs were considered. Capital recovery costs are higher because the equipment life is assumed to be only 8 years on the offshore platform.

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7..0 ENVIRONMENTAL AND ENERGY IMPACTS

This chapter presents environmental and energy impacts for the nitrogen oxide (NO_x) emissions control techniques described in Chapter 5.0. These control techniques are water or steam injection, dry low-NO_x combustors, and selective catalytic reduction (SCR). The impacts of the control techniques on air pollution, solid waste disposal, water pollution, and energy consumption are discussed.

The remainder of this chapter is organized in five sections. Section 7.1 presents the air pollution impacts; Section 7.2 presents the solid waste disposal impacts; Section 7.3 presents the water pollution impacts; and Section 7.4 presents the energy consumption impacts. References for the chapter are listed in Section 7.5.

a. AIR POLLUTION

i. Emission Reductions

Applying any of the control techniques discussed in Chapter 5 will reduce NO_x emissions from gas turbines. These emission reductions were estimated for the model plants presented in Table 6-1 and are shown in Table 7-1. For each model plant, the uncontrolled and controlled emissions, emission reductions, and percent reductions are presented. The following paragraphs discuss NO_x emission reductions for each control technique.

Nitrogen oxide emission reductions for water or steam injection are estimated as discussed in Section 6.1.3. The percent reduction in emissions from uncontrolled levels varies for each model plant ranging, from 60 to 96 percent. This reduction depends on each model's uncontrolled emissions, the

TABLE 7-1. MODEL PLANT UNCONTROLLED AND CONTROLLED NO_x EMISSIONS FOR AVAILABLE NO_x CONTROL TECHNIQUES

Gas turbine model	Annual operating hours	Type of wet injection	Annual emissions[a]	Uncontrolled NO_x emissions,[a] tons/yr	Controlled NO_x emissions, tons/year					SCR NH_3 emissions @ SLIP = 10 ppm (tons/yr)[c]
					Wet injection to levels in Table 6-6	Dry low-NO_x combustor to 42 ppmv	Dry low-NO_x combustor to 25 ppm	Dry low-NO_x combustor to 9 ppmv	NO_x emissions, wet injection + SCR[b]	
Centaur T4500	8,000	Water	Emissions, tons/yr	88.1	28.5	28.5	16.9	NA[d]	6.10	2.92
3.3 MW			Reduction, tons/yr		59.6	59.6	71.2	_	22.4	
Gas fuel			Total reduction, %		68%	68%	81%	_	93%	
501-KB5	8,000	Water	Emissions, tons/yr	126	34.2	NA	NA	NA	7.32	2.58
4.0 MW			Reduction, tons/yr		91.8	_	_	_	26.9	
Gas fuel			Total reduction, %		73%	_	_	_	94%	
LM2500	8,000	Water	Emissions, tons/yr	581	140	NA	NA	NA	30.0	11.2
22.7 MW			Reduction, tons/yr		441	_	_	_	110	
Gas fuel			Total reduction, %		76%	_	_	_	95%	
MS5001P	8,000	Water	Emissions, tons/yr	723	214	NA	NA	NA	45.8	20.4
26.8 MW			Reduction, tons/yr		509	_	_	_	168	
Gas fuel			Total reduction, %		70%	_	_	_	94%	
ABB GT11N	8,000	Water	Emissions, tons/yr	5,410	347	NA	347	125	125	51.7
83.3 MW			Reduction, tons/yr		5,060	_	5060	5290	222	
Gas fuel			Total reduction, %		94%	_	94%	98%	98%	
MS7001E	8,000	Water	Emissions, tons/yr	2,170	593	NA	353	127	127	49.6
84.7 MW			Reduction, tons/yr		1580	_	1820	2040	466	
Gas fuel			Total reduction, %		73%	_	84%	94%	94%	
501-KB5	8,000	Steam	Emissions, tons/yr	126	34.2	NA	NA	NA	7.32	2.58
4.0 MW			Reduction, tons/yr		92	_	_	_	26.9	
Gas fuel			Total reduction, %		73%	_	_	_	94%	
LM2500	8,000	Steam	Emissions, tons/yr	581	83.5	NA	NA	NA	30.0	11.2
22.7 MW			Reduction, tons/yr		498	_	_	_	53.5	
Gas fuel			Total reduction, %		86%	_	_	_	95%	
MS5001P	8,000	Steam	Emissions, tons/yr	723	214	NA	NA	NA	45.8	20.4
26.8 MW			Reduction, tons/yr		509	_	_	_	168	
Gas fuel			Total reduction, %		70%	_	_	_	94%	

TABLE 7-1. (continued)

Gas turbine model	Annual operating hours	Type of wet injection	Annual emissions[a]	Uncontrolled NO_x emissions,[a] tons/yr	Controlled NO_x emissions, tons/year					SCR NH_3 emissions @ SLIP = 10 ppm (tons/yr)[c]
					Wet injection to levels in Table 6-6	Dry low-NO_x combustor to 42 ppmv	Dry low-NO_x combustor to 25 ppm	Dry low-NO_x combustor to 9 ppmv	NO_x emissions, wet injection + SCR[b]	
LM5000	8,000	Steam	Emissions, tons/yr	930	126	NA	NA	NA	45.2	20.5
34.4 MW			Reduction, tons/yr		804	_	_	_	80.8	
Gas fuel			Total reduction, %		86%	_	_	_	95%	
ABB GT11N	8,000	Steam	Emissions, tons/yr	5,410	583	NA	347	125	125	51.7
83.3 MW			Reduction, tons/yr		4830	_	5060	5290	458	
Gas fuel			Total reduction, %		89%	_	94%	98%	98%	
MS7001E	8,000	Steam	Emissions, tons/yr	2,170	593	NA	353	127	127	49.6
84.7 MW			Reduction, tons/yr		1580	_	1820	2040	466	
Gas fuel			Total reduction, %		73%	_	84%	94%	94%	
MS7001F	8,000	Steam	Emissions, tons/yr	5,150	1,030	NA	610	NA	221	71.7
161 MW			Reduction, tons/yr		4120	_	4540	_	809	
Gas fuel			Total reduction, %		80%	_	88%	_	96%	
Centaur T4500	8,000	Water	Emissions, tons/yr	125	41.8	NA	NA	NA	12.5	2.9
3.3 MW			Reduction, tons/yr		83.2	_	_	_	29.3	
Oil fuel			Total reduction, %		67%	_	_	_	90%	
MS5001P	8,000	Water	Emissions, tons/yr	1,090	337	NA	NA	NA	46.6	20.4
26.3 MW			Reduction, tons/yr		753	_	_	_	290	
Oil fuel			Total reduction, %		69%	_	_	_	96%	
MS7001E	8,000	Water	Emissions, tons/yr	3,290	938	NA	NA	NA	130	49.6
83.3 MW			Reduction, tons/yr		2350	_	_	_	808	
Oil fuel			Total reduction, %		71%	_	_	_	96%	
Centaur T4500	2,000	Water	Emissions, tons/yr	22.0	7.1	NA	NA	NA	1.5	0.7
3.3 MW			Reduction, tons/yr		14.9	_	_	_	6	
Gas fuel			Total reduction, %		68%	_	_	_	93%	
MS5001P	2,000	Water	Emissions, tons/yr	181	53.5	NA	NA	NA	11.5	5.1
26.8 MW			Reduction, tons/yr		128	_	_	_	42	
Gas fuel			Total reduction, %		70%	_	_	_	94%	

TABLE 7-1. (continued)

Gas turbine model	Annual operating hours	Type of wet injection	Annual emissions[a]	Uncontrolled NO_x emissions,[a] tons/yr	Controlled NO_x emissions, tons/year					SCR NH_3 emissions @ SLIP = 10 ppm (tons/yr)[c]
					Wet injection to levels in Table 6-6	Dry low-NO_x combustor to 42 ppmv	Dry low-NO_x combustor to 25 ppm	Dry low-NO_x combustor to 9 ppmv	NO_x emissions, wet injection + SCR[b]	
MS7001E	2,000	Water	Emissions, tons/yr	543	148	NA	88	32	31.8	12.4
84.7 MW			Reduction, tons/yr		395	_	455	511	116	
Gas fuel			Total reduction, %		73%	_	84%	94%	94%	
Centaur T4500	2,000	Water	Emissions, tons/yr	31.2	10.0	NA	NA	NA	3.14	0.7
3.3 MW			Reduction, tons/yr		21.2	_	_	_	6.9	
Oil fuel			Total reduction, %		68%	_	_	_	90%	
MS5001P	2,000	Water	Emissions, tons/yr	273	84	NA	NA	NA	23.3	5.1
26.8 MW			Reduction, tons/yr		189	_	_	_	61	
Oil fuel			Total reduction, %		69%	_	_	_	91%	
MS7001E	2,000	Water	Emissions, tons/yr	822	234	NA	NA	NA	64.9	12.4
84.7 MW			Reduction, tons/yr		588	_	_	_	169	
Oil fuel			Total reduction, %		72%	_	_	_	92%	
SATURN T1500	1,000	Water	Emissions, tons/yr	5.00	1.99	NA	NA	NA	0.30	0.13
1.1 MW			Reduction, tons/yr		3	_	_	_	1.7	
Oil fuel			Total reduction, %		60%	_	_	_	94%	
TPM FT4	1,000	Water-in-	Emissions, tons/yr	977	37.3	NA	NA	NA	6.72	NC[e]
28.0 MW		oil	Reduction, tons/yr		940	_	_	_	30.6	_
Oil fuel		emulsion	Total reduction, %		96%	_	_	_	99%	_

[a]Uncontrolled and controlled NO_x emissions are from cost-effectiveness tables in Chapter 6.

[b]Controlled NO_x emission level for wet injection plus SCR is 9 ppmv for natural gas fuel and 18 ppmv for distillate oil fuel.

[c]Ammonia emissions, in tons per year = (SLIP, ppmv) x (MM/1,000,000) x (GT exhaust,lb/sec) x (MW NH3 = 15/MW exhaust = 28.6) x (3,600 sec/hr) x (ton/2,000 lb) x (annual operating hrs).

[d]NA-control technology not available for this model plant.

[e]NC-data not available to calculate emissions for this control scenario.

water-to-fuel ratio (WFR), and type of fuel and whether water or steam is injected.

Achievable emission levels from gas turbines using dry low-NO_x combustors were obtained from manufacturers. Controlled NO_x levels of 42, 25, and 9 parts per million, by volume (ppmv), referenced to 15 percent oxygen, were reported by the various turbine manufacturers, and each of these levels is shown in Table 7-1, where applicable, for each model plant. The percent reduction in NO_x emissions from uncontrolled levels for gas turbines using these combustors ranges from 68 to 98 percent. Virtually all SCR units installed in the United States are used in combination with either wet controls or combustion controls. For this analysis, emission reductions were calculated for SCR in combination with water or steam injection. Using the turbine manufacturers' guaranteed NO_x emissions figures for wet injection and a controlled NO_x emission level of 9 ppmv, referenced to 15 percent oxygen, exiting the SCR, the percent reduction in NO_x emissions for this combination of control techniques ranges from 93 to 99 percent.

Estimated ammonia (NH_3) emissions, in tons per year, corresponding to ammonia slip from the SCR system are also shown in Table 7-1. These estimates are based on an ammonia slip level of 10 ppmv, consistent with information and data presented in Section 5.4. For continuous-duty model plants, the annual NH_3 emissions range from approximately 3 tons for a 3.3 megawatt (MW) (4,425 horsepower [hp]) model plant to 72 tons for a 160 MW (215,000 hp) model plant.

ii. Emissions Trade-Offs

The formation of both thermal and fuel NO_x depends upon combustion conditions. Water/steam injection, lean combustion, and reduced residence time modify combustion conditions to reduce the amount of NO_x formed. These combustion modifications may increase carbon monoxide (CO) and unburned hydrocarbon (HC) emissions. Using SCR to control NO_x emissions produces ammonia emissions. The impacts of these NO_x controls on CO, HC, and ammonia emissions are discussed below.

(1) Impacts of Wet Controls on CO and HC Emissions. As discussed in Section 5.1.5, wet injection may increase CO and HC emissions. Injecting water or steam into the flame area of a turbine combustor lowers the flame temperature and thereby reduces NO_x emissions. This reduction in temperature to some extent inhibits complete combustion, resulting in increased CO and HC emissions. Figure 5-12 shows the impact of water and steam injection on CO emissions for production gas turbines.[2] The impact of steam injection on CO emissions is less than that of water injection. As seen in Figure 5-12, CO emissions increase with increasing WFR's. Wet injection increases HC emissions to a lesser extent than it increases CO emissions. Figure 5-13 shows the impact of water injection on HC emissions for one turbine. In cases where water and steam injection result in excessive CO and HC emissions, an oxidation catalyst (add-on control) can be installed to reduce these emissions by converting the CO and HC to water (H_2O) and carbon dioxide (CO_2).

(2) Impacts of Combustion Controls on CO and HC Emissions. As discussed in Section 5.2.1, the performance of lean combustion in limiting NO_x emissions relies in part on reduced equivalence ratios. As the equivalence ratio is reduced below the stoichiometric level of 1.0, combustion flame temperatures drop, and as a result NO_x emissions are reduced. Shortening the residence time in the high-temperature flame zone also will reduce the amount of thermal NO_x formed. These lower equivalence ratios and/or reduced residence time, however, may result in incomplete combustion, which may increase CO and HC emissions. The extent of the increase in CO and HC emissions is specific to each turbine manufacturer's combustor designs and therefore varies for each turbine model. As with wet injection, if necessary, an oxidation catalyst can be installed to reduce excessive CO and HC emissions by converting the CO and HC to CO_2 and H_2O.

(3) Ammonia Emissions from SCR. The SCR process reduces NO_x emissions by injecting NH_3 into the flue gas. The NH_3 reacts with NO_x in the presence of a catalyst to form H_2O and nitrogen

(N_2). The NO_x removal efficiency of this process is partially dependent on the NH_3/NO_x ratio. Increasing this ratio reduces NO_x emissions but increases the probability that unreacted ammonia will pass through the catalyst unit into the atmosphere (known as ammonia "slip"). Some ammonia slip is unavoidable because of ammonia injection control limitations and imperfect distribution of the reacting gases. A properly designed SCR system will limit ammonia slip to less than 10 ppmv (see Section 5.4).

b. SOLID WASTE DISPOSAL

Catalytic materials used in SCR units for gas turbines include precious metals (e.g., platinum), zeolites, and heavy metal oxides (e.g., vanadium, titanium). Vanadium pentoxide, the most commonly used SCR catalyst in the United States, is identified as an acute hazardous waste under RCRA Part 261, Subpart D - Lists of Hazardous Wastes. The Best Demonstrated Available Technology (BDAT) Treatment Standards for Vanadium P119 and P120 states that spent catalysts containing vanadium pentoxide are not classified as hazardous waste.[1] State and local regulatory agencies, however, are authorized to establish their own hazardous waste classification criteria, and spent catalysts containing vanadium pentoxide may be classified as a hazardous waste in some areas. Although the actual amount of vanadium pentoxide contained in the catalyst bed is small, the volume of the catalyst unit containing this material is quite large and disposal can be costly. Where classified by State or local agencies as a hazardous waste, this waste may be subject to the Land Disposal Restrictions in 40 CFR Part 268, which allows land disposal only if the hazardous waste is treated in accordance with Subpart D - Treatment Standards. Such disposal problems are not encountered with other catalyst materials, such as precious metals and zeolites, because these materials are not hazardous wastes.

c. WATER USAGE AND WASTE WATER DISPOSAL

Water availability and waste water disposal are environmental factors to be considered with wet injection. The impact of water usage on the water supply at some remote sites,

in small communities, or in areas where water resources may be limited is an environmental factor that should be examined when considering wet injection. The volume of water required for wet injection is shown in Table 7-2

TABLE 7-2. WATER AND ELECTRICITY CONSUMPTION FOR NO_x CONTROL TECHNIQUES

Gas turbine model[a]	Turbine power output, MW	Annual operating hours	Fuel type	Type of emission control	Total water flow, gal/min[a]	Waste water flow, gal/min[b]	Water pump power, kW[c]	Wet injection power consumption, kW-hr/yr[d]	SCR power penalty, kW-hr/yr[e]
Centaur T4500	3.3	8,000	Gas	Water inj.	2.5	0.73	0.40	3,220	132,000
501-KB5	4.0	8,000	Gas	Water inj.	3.94	1.14	0.63	5,070	160,000
LM2500	22.7	8,000	Gas	Water inj.	14.8	4.29	2.38	19,100	908,000
MS5001P	26.8	8,000	Gas	Water inj.	22.2	6.44	3.57	28,600	1,070,000
ABB GT11N	83.3	8,000	Gas	Water inj.	154	44.7	24.8	198,000	3,330,000
MS7001E	84.7	8,000	Gas	Water inj.	69.2	20.1	11.1	89,100	3,390,000
501-KB5	4.0	8,000	Gas	Steam inj.	7.38	2.14	1.19	9,510	160,000
LM2500	22.7	8,000	Gas	Steam inj.	29.5	8.56	4.75	38,000	908,000
MS5001P	26.8	8,000	Gas	Steam inj.	33.3	9.66	5.36	42,900	1,070,000
LM5000	34.4	8,000	Gas	Steam inj.	50.8	14.7	8.18	65,400	1,380,000
ABB GT11N	83.3	8,000	Gas	Steam inj.	178	51.6	28.7	229,000	3,330,000
MS7001E	84.7	8,000	Gas	Steam inj.	104	30.2	16.7	134,000	3,390,000
MS7001F	161	8,000	Gas	Steam inj.	199	57.7	32.0	256,000	6,440,000
Centaur T4500	3.3	8,000	Oil	Water inj.	2.76	0.80	0.44	3,550	132,000
MS5001P	26.3	8,000	Oil	Water inj.	26.7	7.74	4.30	34,400	1,050,000
MS7001E	83.3	8,000	Oil	Water inj.	63.8	18.5	10.3	82,200	833,000
Centaur T4500	3.3	2,000	Gas	Water inj.	2.50	0.73	0.40	3,220	33,000
MS5001P	26.3	2,000	Gas	Water inj.	22.2	6.44	3.57	28,600	263,000
MS7001E	84.7	2,000	Gas	Water inj.	69.2	20.1	11.1	89,100	847,000
Centaur T4500	3.3	2,000	Oil	Water inj.	2.76	0.80	0.44	3,550	33,000
MS5001P	26.3	2,000	Oil	Water inj.	26.7	7.74	4.30	34,400	263,000
MS7001E	84.7	2,000	Oil	Water inj.	63.8	18.5	10.3	82,200	847,000
SATURN T1500	1.1	1,000	Oil	Water inj.	0.81	0.23	0.13	1,040	5,500
TPM FT4	28.0	1,000	Oil	Water-in-oil emulsion	21.7	6.29	3.49	27,900	140,000

[a]From Table 6-2.

[b]Calculated as 29 percent of the total water flow.

[c]Power requirement for water pump is calculated as shown in Section 6.1.2.2.

for each model plant.

Water purity is essential for wet injection systems in order to prevent erosion and/or the formation of deposits in the hot sections of the gas turbine. Water treatment systems are used to achieve water quality specifications set by gas turbine manufacturers. Table 5-4 summarizes these specifications for six manufacturers.

Discharges from these water treatment systems have a potential impact on water quality. As indicated in Section 6.1, approximately 29 percent of the treated water flow rate (22.5 percent of the raw water flow rate) is considered to be discharged as wastewater. The wastewater flow rates for each of the model plants with a water or steam injection control system are estimated using this factor, and the results are presented in Table 7-2. The wastewater contains increased levels of those pollutants in the raw water (e.g., calcium, silica, sulfur, as listed in Table 5-4) that are removed by the water treatment system, along with any chemicals introduced by the treatment process. Based on a wastewater flowrate equal to 29 percent of the influent raw water, the concentration of pollutants discharged from the water treatment system is approximately three times higher than the pollutant concentrations in the raw water.

The impacts of these pollutants on water quality are site-specific and depend on the type of water supply and on the discharge restrictions. Influent water obtained from a municipality will not contain high concentrations of pollutants. However, surface water or well water used at a remote site might contain high pollutant concentrations and may require additional pretreatment to meet the water quality specifications set by

manufacturers. This additional pretreatment will increase the pollutant concentrations of the wastewater discharge. Wastewater discharges to publicly-owned treatment works (POTW's) must meet the requirements of applicable Approved POTW Pretreatment Programs.

d. ENERGY CONSUMPTION

Additional fuel and electrical energy is required over baseline for wet injection controls, while additional electrical energy is required for SCR controls. The following paragraphs discuss these energy consumption impacts.

Injecting water or steam into the turbine combustor lowers the net cycle efficiency and increases the power output of the turbine. The thermodynamic efficiency of the combustion process is reduced because energy that could otherwise be available to perform work in the turbine must now be used to heat the water/steam. This lower efficiency is seen as an increase in fuel use. Table 5-10 shows the impacts of wet injection on gas turbine performance for one manufacturer. This table shows a 2 to 4 percent loss in efficiency associated with WFR's required to achieve NO_x emission levels of 25 to 42 ppmv in gas turbines burning natural gas. The actual efficiency loss is specific to each turbine model but generally increases with increasing WFR's and is higher for water injection than for steam injection (additional energy is required to heat and vaporize the water). One exception to this efficiency penalty occurs with steam injection, in which exhaust heat from the gas turbine is used to generate the steam for injection. If the heat recovered in generating the steam would otherwise be exhausted to atmosphere, the result is an increase in net cycle efficiency.

The energy from the increased mass flow and heat capacity of the injected water/steam can be recovered in the turbine, resulting in an increase in power output accompanying the reduced efficiency of the turbine (shown in Table 5-10 for one manufacturer). This increase in power output can be significant and could lessen the impact of the loss in efficiency if the facility has a demand for the available excess power.

Water and steam injection controls also require additional electrical energy to operate the water injection feed water pumps. The annual electricity usage for each model is the product of the pump power demand, discussed in Section 6.1.2.2, and the annual hours of operation. Table 7-2 summarizes this electricity usage for each of the model plants.

For SCR units, additional electrical energy is required to operate ammonia pumps and ventilation fans. This energy requirement, however, is believed to be small and was not included in this analysis.

The increased back-pressure in the turbine exhaust system resulting from adding an SCR system reduces the power output from the turbine. As discussed in Section 6.3.2.9, the power output is typically reduced by approximately 0.5 percent. This power penalty has been calculated for each model plant and is shown in Table 7-2.

e. REFERENCE FOR CHAPTER 7

1.. 55 FR 22276, June 1, 1990.

APPENDIX A

Exhaust NO_x emission levels were provided by gas turbine manufacturers in units of parts per million, by volume (ppmv), on a dry basis and corrected to 15 percent oxygen. A method of converting these exhaust concentration levels to a mass flow rate of pounds of NO_x per hour (lb NO_x/hr) was provided by one gas turbine manufacturer.[1] This method uses an emission index ($EINO_x$), in units of lb NO_x/1,000 lb fuel, which is proportional to the exhaust NO_x emission levels in ppmv by a constant, K. The relationship between $EINO_x$ and ppmv for NO_x emissions is stated in Equation 1 below and applies for complete combustion of a hydrocarbon fuel and combustion air having no CO_2 and an O_2 mole percent of 20.95:

$$\frac{NO_x \text{ Ref. } 15\% \ 0_2}{EINO_x} = K \qquad \text{Equation 1}$$

where: NO_x Ref. 15% 0_2 = NO_x, ppmvd @15% O_2 (provided by gas turbine manufacturers);

$EINO_x$ = NO_x emission index, lb NO_x/1,000 lb fuel; and

K = constant, based on the molar hydrocarbon

ratio of the fuel.

The derivation of Equation 1 was provided by the turbine manufacturer and is based on basic thermodynamic laws and supported by test data provided by the manufacturer. According to the manufacturer, this equation can be used to estimate NO_x emissions for operation with or without water/steam injection.

Equation 1 shows that NO_x emissions are dependent only upon the molar hydrocarbon ratio of the fuel and are independent of the air/fuel ratio (A/F). The equation therefore is valid for all gas turbine designs for a given fuel. The validity of this approach to calculate NO_x emissions was supported by a second

turbine manufacturer.[2] Values for K were provided for several fuels and are given below:[1,2]

Pipeline quality natural gas:

K = 12.1

Distillate fuel oil No. 1 (DF-1):

K = 13.1

Distillate fuel oil No. 2 (DF-2):

K = 13.2

Jet propellant No. 4 (JP-4):

K = 13.0

Jet propellant No. 5 (JP-5):

K = 13.1

Methane:

K = 11.6

The following examples are provided for calculating NO_x emissions on a mass basis, given the fuel type and NO_x emission level, in ppmv, dry (ppmvd), and corrected to 15 percent O_2.

Example 1. Natural gas fuel

Gas turbine:
Solar Centaur 'H'
Power output:
4,040 kW
Heat rate:
12,200 Btu/kW-hr
NO_x emissions:
105 ppmvd, corrected to 15 percent O_2
Fuel:

Natural gas

- lower heating value = 20,610 Btu/lb

- K = 12.1

Fuel flow:

$$4{,}040 \text{ kW} \times \frac{12{,}200 \text{ Btu}}{\text{kW-hr}} \times \frac{1 \text{ lb fuel}}{20{,}610 \text{ Btu}} = 2{,}391 \text{ lb/hr}$$

From Equation 1:

$$\frac{105}{EINO_x} = 12.1$$

NO_x emissions, lb/hr:

$$2{,}391 \frac{\text{lb fuel}}{\text{hr}} \times \frac{8.68 \text{ lb } NO_x}{1{,}000 \text{ lb fuel}} = 20.8 \frac{\text{lb } NO_x}{\text{hr}}$$

Example 2. Distillate oil fuel

Gas turbine:

General Electric LM2500

Power output:

22670 kW

Heat rate:

9296 Btu/kW-hr

No_x emissions: 345 ppmvd, corrected to 15 percent O_2

Fuel:

Distillate oil No. 2

-

lower heating value = 18,330 Btu/lb

- K = 13.2

Fuel flow:

$$22{,}670 \text{ kW} \times 9296 \frac{\text{Btu}}{\text{kW-hr}} \times \frac{1 \text{ lb fuel}}{18{,}330 \text{Btu}} = 11{,}500 \text{ lb/hr}$$

From Equation 1:

$$\frac{345}{EINO_x} = 13.2$$

NO_x emissions, lb/hr:

$$11{,}500 \frac{\text{lb fuel}}{\text{hr}} \times \frac{26.1 \text{ lb } NO_x}{1{,}000 \text{ lb fuel}} = 300 \frac{\text{lb } NO_x}{\text{hr}}$$

REFERENCES FOR APPENDIX A:

1. Letter and attachments from Lyon, T.F., General Electric Aircraft Engines, to Snyder, R.B., MRI. December 6, 1991. Calculation of NO_x emissions from gas turbines.

2. Letter and attachments from Hung, W.S., Solar Turbines, Inc., to Snyder, R.B., MRI. December 17, 1991. Calculation of NO_x emissions from gas turbines.

APPENDIX B. COST DATA AND METHODOLOGY USED TO PREPARE COST FIGURES PRESENTED IN CHAPTER 6

APPENDIX B. RAW COST DATA AND COST ALGORITHMS

The maintenance costs for water injection and several of the SCR costs presented in Chapter 5 are based on information from turbine manufacturers and other sources that required interpretation and analysis. Information about additional gas turbine maintenance costs associated with water injection is presented in Section B.1. Information on SCR capital costs, catalyst replacement and disposal costs, and maintenance costs is presented in Section B.2. References are listed in Section B.3.

B.1 WATER INJECTION MAINTENANCE COSTS

Information from each manufacturer and the applicable analysis procedures used to develop maintenance cost impacts for water injection are described in the following sections.

B.1.1 Solar

This manufacturer indicated that the annual maintenance cost for the Centaur is $16,000/year.[1] The cost for the Saturn was estimated to be $8,000.[2] This $8,000 cost was then prorated for operation at 1,000/hr/yr, and was multiplied by 1.3 to account for the additional maintenance required for oil fuel.

B.1.2 Allison

Maintenance costs for water injection were provided by a company that packages Allison gas turbines for stationary applications. This packager stated that for the 501 gas turbine model, a maintenance contract is available which covers all maintenance materials and labor costs associated with the turbine, including all scheduled and unscheduled activities. The cost of this contract for the 501 model is $0.0005 to $0.0010 per KW-hour (KWH) more for water injection than for a turbine not using water injection.[3] For an installation operating 8,000 hours per year at a base-rated output of 4,000 KW, and using an average cost of $0.00075 per KWH, the annual additional maintenance cost is $24,000. By the nature of the contract offered, this figure represents a worst case scenario and to some extent may exceed the actual incremental maintenance costs that would be expected for water injection for this turbine.

B.1.3 General Electric

General Electric (GE) offers both aero-derivative type (LM-series models) and heavy-duty type (MS-series models) gas turbines. For the aero-derivative turbines, GE states that the incremental maintenance cost associated with water injection is $3.50 per fired hour. This cost is used to calculate the maintenance cost for water injection for GE aeroderivative turbines. No figures were provided for steam injection and no maintenance cost was used for steam injection with these turbines.[4]

Water injection also impacts the maintenance costs for the heavy-duty MS-series models. Costs associated with more frequent maintenance intervals required for models using water injection have been calculated and summarized below. A GE representative stated that the primary components which must be repaired at each maintenance interval are the combustor liner and transition pieces.[5] Approximate costs to repair these pieces were provided by GE.[5] For this analysis, the maximum cost estimates were used to calculate annual costs to accommodate repairs that may be required periodically for injection nozzles, cross-fire tubes, and other miscellaneous hardware. According to GE, a rule of thumb is that if the repair cost exceeds 60 percent of the cost of a new part, the part is replaced.[5] The cost of a replacement part is therefore considered to be 1.67 times the maximum repair cost. If water purity requirements are met, there are no significant adverse impacts on maintenance requirements on other turbine components, and hot gas path inspections and major inspection schedules are not impacted.[5] Combustion repair schedules, material costs, and labor hours are shown in Table B-1. Scheduled maintenance intervals for models with water injection were provided in Reference 6. Corresponding maintenance intervals for models with steam injection were assumed to be the same as models with no wet injection; these scheduled maintenance intervals were provided in Reference 7. Using the information in Table B-1, the total annual cost is

calculated and shown in Table B-2 for three GE heavy-duty turbine models.

B.1.4 Asea Brown Boveri

This manufacturer states there are no maintenance impacts associated with water injection.[8]

B.2 SCR COSTS

The total capital investment, catalyst replacement, and maintenance costs are estimated based on information from the technical literature. The cost algorithms are described in the following sections.

B.2.1 Total Capital Investment

Total capital investment costs, which include purchased costs and installation costs, were available for SCR systems for combined cycle and cogeneration applications from five sources.[9-13] These costs were scaled to 1990 costs using the Chemical Engineering annual plant cost indexes and are applicable to SCR systems in which the catalyst was placed within the heat recovery steam generator (HRSG). In addition, estimated capital investment costs were available from one source for SCR systems in which a high temperature zeolite catalyst is installed upstream of the HRSG.[14] Both the original data and the scaled costs are presented in Table B-3. The scaled costs were plotted against the turbine size and this plot is shown in Figure B-1. A linear regression analysis was performed to determine the equation for the line that best fits the data. This equation was used to estimate the total capital investment for SCR for the model plants and was extrapolated to estimate the costs for model plants larger than 90 MW.

B.2.2 Maintenance Costs

Maintenance costs for SCR controls were obtained from four literature sources, although 6 of the 14 points were obtained from one article.[9,11-13] These costs were scaled to 1990 costs assuming an inflation rate of five percent per year. All of the data are for turbines that use natural gas fuel. Because there are no data to quantify differences in SCR maintenance costs for oil-fired applications, the available data for operation on

natural gas were used for both fuels. Both the original data and the scaled costs are presented in Table B-4. The scaled costs were plotted versus the turbine size in Figure B-2. The equation for the line through the data was determined by linear regression, and it was used to estimate the maintenance costs for the model plants.

B.2.3 Catalyst Replacement Costs

Catalyst replacement costs were obtained from three articles for nine gas turbine installations.[9,11,13] Combined catalyst replacement and disposal costs were obtained for another six gas turbine installations from one article.[12] The disposal costs for these six gas turbine installations were estimated based on estimated catalyst volumes and a unit disposal cost of $\$15/ft^3$, given in Reference 15.

The catalyst volumes were estimated assuming there is a direct relationship between the volume and the turbine size; the catalyst volume stated in Reference 16 for one 83 MW turbine is 175 m^3. The resulting disposal costs for these six facilities were subtracted from the combined replacement and disposal costs to estimate the replacement-only costs. All of the replacement costs were scaled to 1990 costs assuming an inflation rate of 5 percent per year. The original data and the scaled costs are presented in Table B-5, and the scaled replacement costs were also plotted versus the turbine size in Figure B-3. Linear regression was used to determine the equation for the line through the data. This equation was used to estimate the catalyst replacement costs for the model plants.

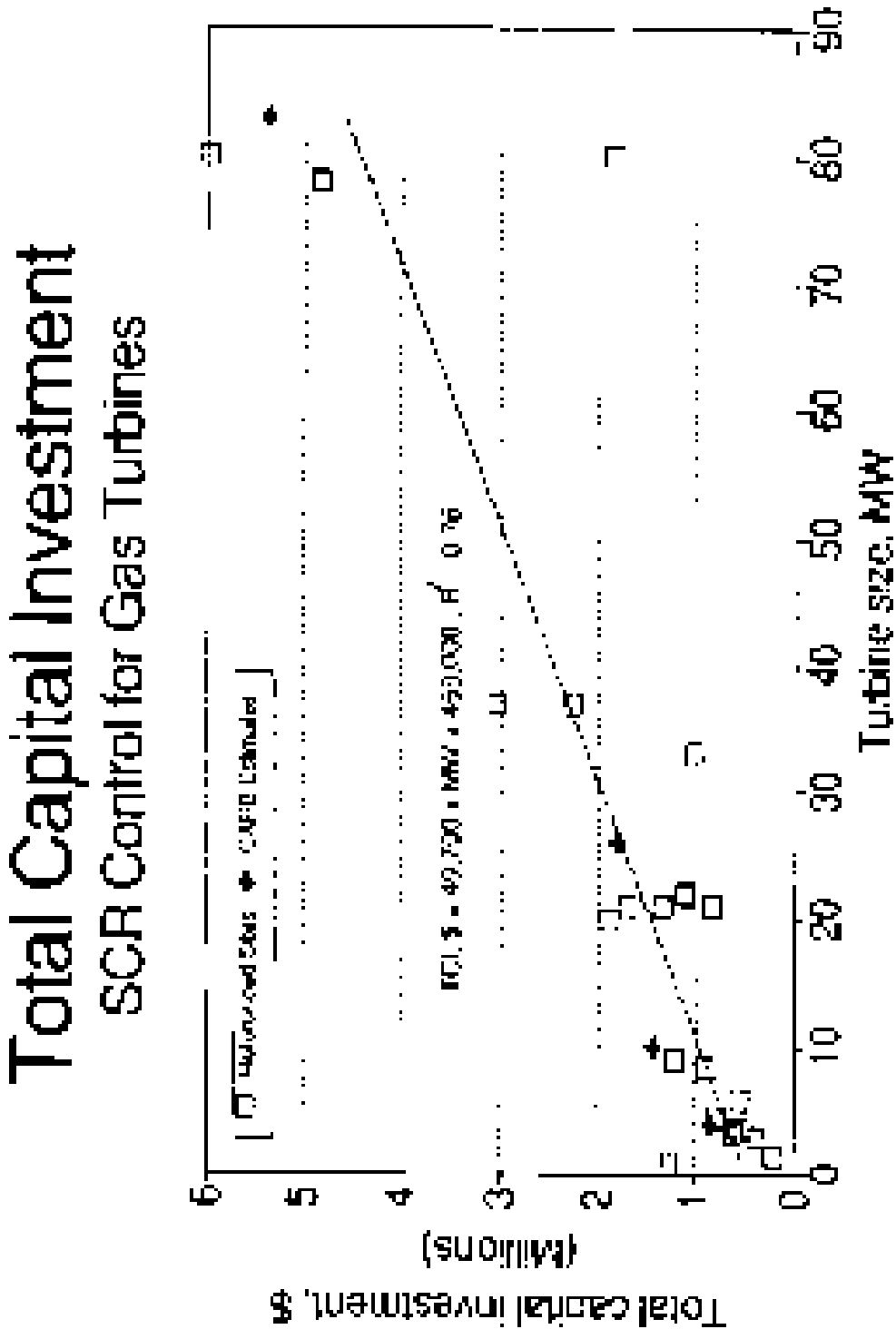


Figure B-1. Total Capital Investment for SCR Control of NO_x Emissions from Gas Turbines

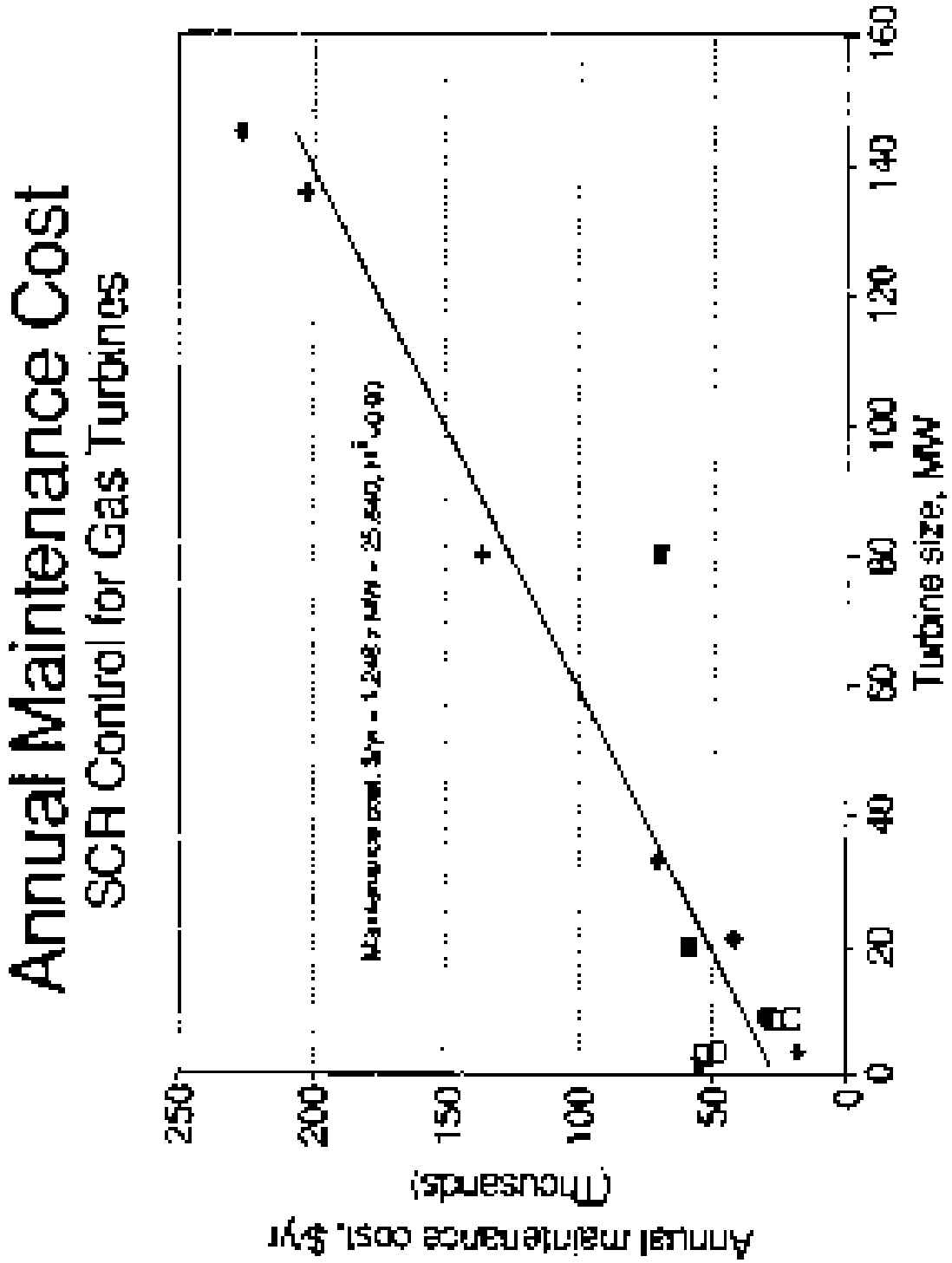


Figure B-2. Annual Maintenance Cost for SCR Control of NO_x Emissions from Gas Turbines

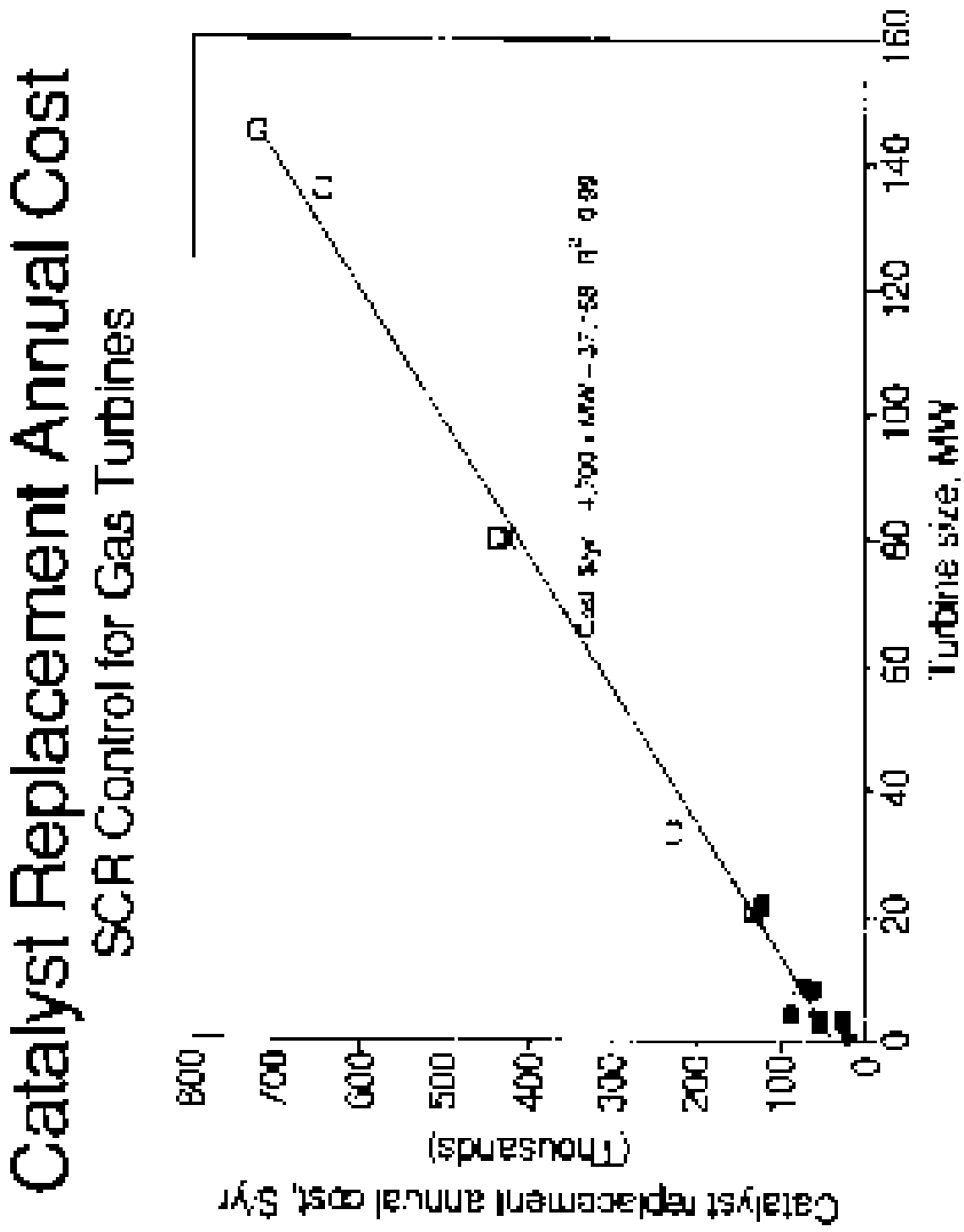


Figure B-3. Catalyst Replacement Annual Cost for SCR Control of Gas Turbines

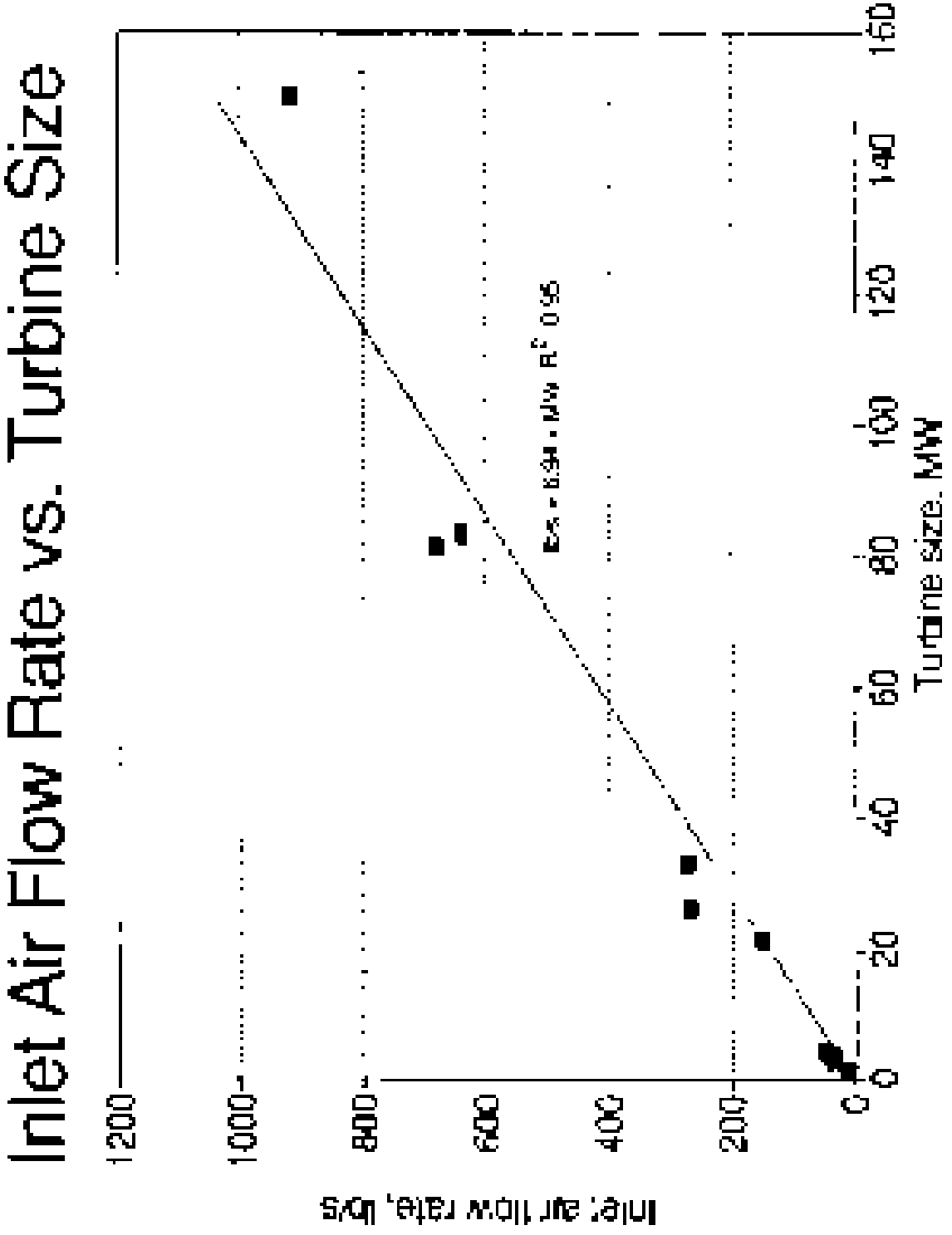


Figure B-4. Inlet Air Flow Rate for Gas Turbines

TABLE B-1. COMBUSTOR REPAIR INTERVALS, HOURS, AND MATERIAL COST

Gas turbine	Repair interval, hr		Replacement interval, hr		Repair cost, $[d]	Replacement cost, $[d]	Item	Labor hours [a]
	Dry	Wet[b]	Dry[a]	Wet[c]				
MS5001P	12,000	6,000	48,000	24,000	10,000-15,000 15,000-20,000	25,000 42,000	Liners Transition pieces	160
MS7001E	8,000	6,500	48,000	39,000	15,000-30,000 30,000-50,000	50,000 83,000	Liners Transition pieces	576
MS9001E	8,000	6,500	48,000	39,000	31,000-62,000 62,000-124,000	103,000 206,000	Liners Transition pieces	624

[a]Reference 7.
[b]Reference 6.
[c]Scaled from Dry Repair/Replace intervals found in Reference 9.
[d]Reference 5.

TABLE B-2. ANNUAL COST OF ADDITIONAL MAINTENANCE REQUIRED FOR WATER INJECTION

	Number of inspections over 15 years						Material costs		Labor, each inspection		Total added cost 15 years	Total added annual cost
	Dry		Wet		Added number for wet							
GT Model	Inspection	Replacement	Inspection	Replacement	Inspection	Replacement	Inspection	Replacement	Hours	Cost		
MS5001P [a]												
Combustor liners	8	2	15	5	7	3	15,000	25,000			18,000	
Transition pieces	8	2	15	5	7	3	20,000	42,000	160	4,998	315,980	
											495,980	33,065
MS7001E [e]												
Combustor liners	12	3	15	3.5	3	0.5	30,000	50,000			115,000	
Transition pieces	13	2	15.5	3	2.5	1	50,000	83,000	576	17,994	270,979	
											385,979	25,732
MS9001E [e]												
Combustor liners	12	3	15	3.5	3	0.5	62,000	103,000			237,500	
Transition pieces	13	2	15.5	3	2.5	1	124,000	206,000	624	19,494	584,229	
											821,729	54,782

[a]Based on $31.24/hr. Since parts are normally removed and a spare set is installed at each inspection, the labor cost would be the same for either repair or replacement interval.

[b]Schedule assumes liners and transition pieces are replaced every fourth inspection interval.

[c](7 x $15,000) + (3 x $25,000) = $180,000.

[d](7 x $20,000) + (3 x $42,000) + ($4,998 x 10) = $315,980.

[e]Schedule assumes liners are replaced every fifth interval and transition pieces every sixth interval.

TABLE B-3. TOTAL CAPITAL INVESTMENT FOR SCR TO CONTROL NO_x EMISSIONS FROM GAS TURBINES

Gas turbine size, MW	SCR capital cost[a]			Scaling factor[c]	1990 SCR capital cost, $
	$	Year	Ref[b]		
1.1	1,250,000	1989	9	357.6/355.4	1,260,000
1.5	180,000	1986	10	357.6/318.4	202,000
3	320,000	1986	10	357.6/318.4	359,000
3.2	600,000	1989	11	357.6/3.554	604,000
3.7	477,000	1988	12	357.6/342.5	498,000
3.7	579,000	1989	11	357.6/355.4	583,000
4	839,000	1991	14	1.0	839,000
4.5	750,000	1988	11	357.6/342.5	783,000
6	480,000	1986	10	357.6/318.4	539,000
8.4	800,000	1986	11	357.6/318.4	898,000
9	1,100,000	1987	13	357.6/323.8	1,210,000
10	1,431,000	1991	14	1.0	1,431,000
20	1,700,000	1987	13	357.6/323.8	1,880,000
21	798,000	1988	12	357.6/342.5	833,000
21	1,500,000	1986	10	357.6/318.4	1,680,000
21	1,200,000	1986	10	357.6/318.4	1,350,000
22	1,000,000	1987	11	357.6/323.8	1,100,000
26	1,800,000	1991	14	1.0	1,800,000
33	990,000	1988	12	357.6/342.5	1,030,000
37	2,000,000	1986	11	357.6/318.4	2,250,000
37	2,700,000	1986	10	357.6/318.4	3,030,000
78	4,300,000	1986	10	357.6/318.4	4,830,000
80	5,400,000	1987	13	357.6/323.8	5,960,000
80	1,760,000	1988	12	357.6/342.5	1,840,000
83	5,360,000	1991	14	1.0	5,360,000

continued

TABLE B-3. (Continued)

[a]Total capital costs were provided by several sources, but it is not clear that they are on the same basis. For example, it is likely that the type of catalyst varies and the target NO_x reduction efficiency may also vary. In addition, some estimates may not include costs for emission monitors; auxiliary equipment like the ammonia storage, handling, and transfer system; taxes and freight; or installation.

[b]Reference 12 also provided costs for SCR used with 136 MW and 145 MW turbines. All of the costs for this reference are lower than the costs from other sources, and the differential increases as the turbine size increases. Because there are no costs from other sources for such large turbines, these two data points would exert undue influence on the analysis; therefore, they have been excluded. Costs for large model plants were estimated by extrapolating with the equation determined by linear regression through the data for turbines with capacities less than 90 MW (see Figure B-1).

[c]Costs for years prior to 1990 are adjusted to 1990 dollars based on the annual CE plant cost indexes. Costs estimated in 1991 dollars were not adjusted.

TABLE B-4. MAINTENANCE COSTS FOR SCR

Gas turbine size, MW	SCR maintenance cost[a]			Scaling factor[b]	1990 SCR maintenance cost, $
	$/yr	Year	Ref		
1.1	52,200	1989	9	1.050	54,800
3.2	50,000	1989	11	1.050	52,500
3.7	43,000	1988	11	1.103	47,400
3.7	15,500	1988	12	1.103	17,100
8.4	22,000	1986	11	1.216	26,700
8.9	18,000	1988	11	1.103	19,800
9	25,000	1987	13	1.158	28,900
20	50,000	1987	13	1.158	57,900
21	37,900	1988	12	1.103	41,800
33	63,700	1988	12	1.103	70,200
80	124,000	1988	12	1.103	137,000
80	60,000	1987	13	1.158	69,500
136	184,000	1988	12	1.103	203,000
145	205,000	1988	12	1.103	226,000

[a]All of the maintenance costs are for turbines that are fired with natural gas. Although sulfur in diesel fuel can cause maintenance problems, there are no data to quantify the impact. Therefore, the maintenance costs presented in this table were used for both natural gas and diesel fuel applications.
[b]Scaling factors are based on an estimated inflation rate of 5 percent per year.

TABLE B-5. CATALYST REPLACEMENT AND DISPOSAL COSTS

Gas turbine size, MW	Catalyst replacement cost [a]						Catalyst disposal cost			Catalyst replacement and disposal annual cost, $/yr
	$	Year	Ref.	Scaling factor[b]	1990 catalyst cost, $	Annual cost, $/yr[c]	Catalyst volume, m^3	1990 cost, $[e]	Annual cost, $/yr[c]	
1.1	74,600	1989	9	1.050	78,300	20,700	2.32	1,230	324	21,000
3.2	200,000	1989	11	1.050	210,000	55,400	6.75	3,570	940	56,300
3.7		1988	12	1.103	215,000	56,600	7.80	4,130	1,090	57,700
3.7	100,000	1988	11	1.103	110,000	29,000	7.80	4,130	1,090	30,100
4.5	300,000	1988	11	1.103	331,000	87,300	9.49	5,030	1,330	89,000
8.4	200,000	1986	11	1.216	243,000	64,100	17.7	9,380	2,470	67,000
9	255,000	1987	13	1.158	295,000	77,800	19.0	10,100	2,660	80,000
20	434,000	1987	13	1.158	502,000	132,000	42.2	22,300	5,880	138,000
21		1988	12	1.103	512,000	135,000	44.3	23,500	6,200	141,000
22	400,000	1987	11	1.158	463,000	122,000	46.4	24,600	6,490	128,000
33		1988	12	1.103	864,000	228,000	69.6	36,900	9,700	238,000
80		1988	12	1.103	1,660,000	437,000	169	89,300	23,600	461,000
80	1,400,000	1987	13	1.158	1,620,000	427,000	169	89,300	23,600	451,000
136		1988	12	1.103	2,450,000	645,000	287	152,000	40,100	685,000
145		1988	12	1.103	2,740,000	723,000	306	162,000	42,700	766,000

[a]Reference 12 provided only combined catalyst replacement and disposal costs.

[b]Scaling factors are based on an inflation rate of 5 percent per year.

[c]Annual costs are based on the assumption that the catalyst will be replaced every 5 years. Therefore, the capital recovery factor is 0.2638, assuming an annual interest rate of 10 percent.

[d]In one SCR application, 175 m^3 of catalyst is used with an 83 MW turbine. If the space velocity is the same for any size SCR (assuming the same catalyst), then there is a direct relationship between the amount of catalyst and the exhaust gas flow rate. The exhaust gas flow rate was calculated as equal to the inlet air flow rate, and as Figure B-4 shows, there is nearly a direct relationship between the inlet airflow rate and turbine capacity. Therefore, the catalyst volume for the turbines in this table were estimated assuming there is a direct relationship between the catalyst volume and the turbine output.

[e]Disposal costs are estimated based on a unit cost of $15/$ft^3$.

B.3 REFERENCES FOR APPENDIX B

I. Letter and attachments from Swingle, R., Solar Turbines Incorporated, to Snyder, R., MRI. May 21, 1991. Maintenance considerations for gas turbines.

II. Letter and attachments from Swingle, R., Solar Turbines Incorporated, to Neuffer, W.J., EPA/ISB. August 20, 1991. Review of draft gas turbine ACT document.

III. Letter and attachments from Lock, D., U.S. Turbine Corporation, to Neuffer, W.J., U.S EPA/ISB. September 17, 1991. Review of draft gas turbine ACT document.

IV. Letter and attachments from Sailer, E.D., General Electric Marine and Industrial Engines, to Neuffer, W.J., EPA/ISB. August 29, 1991. Review of draft gas turbine ACT document.

V. Telecon. Snyder, R., MRI, with Pasquarelli, L., General Electric Company. April 26, 1991. Maintenance costs for gas turbines.

VI. Letter and attachment from Schorr, M., General Electric Company, to Snyder, R., MRI. April 1, 1991. Response to gas turbine questionnaire.

VII. Walsh, E. Gas Turbine Operating and Maintenance Considerations. General Electric Company. Schenectady, NY. Presented at the 33rd GE Turbine State-of-the-Art Technology Seminar for Industrial, Cogeneration and Independent Power Turbine Users. September, 1989. 20 pp.

VIII. Letter and attachments from Gurmani, A., Asea Brown Boveri, to Snyder, R., MRI. May 30, 1991. Response to gas turbine questionnaire.

IX. Permit application processing and calculations by South Coast Air Quality Management District for proposed SCR control of gas turbine at Saint John's Hospital and Health Center, Santa Monica, California. May 23, 1989.

X. Hull, R., C. Urban, R. Thring, S. Ariga, M. Ingalls, and G. O'Neal. NO_x Control Technology Data Base for Gas-Fueled Prime Movers, Phase I. Prepared by Southwest Research Institute for Gas Research Institute. April 1988.

XI. Shareef, G., and D. Stone. Evaluation of SCR NO_x Controls for Small Natural Gas-Fueled Prime Movers. Phase I. Prepared by Radian Corporation for Gas Research Institute. July 1990.

XII. Sidebotham, G., and R. Williams. Technology of NO_x Control for Stationary Gas Turbines. Center for Environmental Studies. Princeton University. January 1989.

XIII. Prosl, T., DuPont,and Scrivner, G., Dow. Technical Arguments and Economic Impact of SCR's Use for NO_x Reduction of Combustion Turbine for Cogeneration. Paper presented at EPA Region 6 meeting concerning NO_x abatement of Combustion Turbines. December 17, 1987.

XIV. State of California Air Resources Board. Draft Proposed Determination of Reasonably Available Control Technology And Best Available Retrofit Technology for Stationary Gas Turbines. August, 1991. Appendix C.

XV. Letter and attachments from Henegan, D., Norton Company, to Snyder, R., MRI. March 28, 1991. Response to SCR questionnaire.

XVI. Schorr, M. NO_x Control for Gas Turbines: Regulations and Technology. General Electric Company. Schenectady, New York. Paper presented at the Council of Industrial Boiler Owners NO_x Control IV Conference. Concord, California. February 11-12, 1991. 11 pp.

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation
DIVISION OF AIR QUALITY
Director's Office
[illegible]

CERTIFIED MAIL: 7017 3040 0000 4359 5219
Return Receipt Requested

September 13, 2018

Naomi Knight, Environmental Officer
Golden Valley Electric Association
PO Box 71249
Fairbanks, AK 99707-1249

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum from Golden Valley Electric Association (GVEA) for the North Pole Power Plant and Zehnder Facility by November 1, 2018

Dear Ms. Knight:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that GVEA North Pole and Zehnder and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to a Serious Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measure (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as GVEA North Pole and Zehnder. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analyses are a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an email to Ms. Naomi Knight at GVEA on May 11, 2017 notifying her of the reclassification

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 [illegible]

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-09-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(a)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.

[3] https://www.gpo.gov/fdsys/pkg/FR-2016-09-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.

to Serious and included a request for the BACT analysis to be completed by August 8, 2017. The BACT analyses from GVEA North Pole and Zehnder, which included emission units found in Operating Permits AQ0110TVP03 and AQ0109TVP03, were submitted by email to the Department on August 30, 2017.

On March 22, 2018, ADEC released a preliminary draft of the BACT determination for GVEA for public discussion on its website at: http://dec.alaska.gov/air/anpms/comm/comm_fbks.htm. As indicated in the release, this document is a work in progress. ADEC received additional information from the EPA on the preliminary draft BACT determination and expects to make changes to the determination based upon this input. Therefore, ADEC is requesting additional information from GVEA to assist it in making a legally and practicably enforceable BACT determination for the source.

If ADEC does not receive a response to this information request by November 1, 2018, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facility's infrastructure and without additional information, may select a more stringent BACT for your facility in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public review along with any precursor demonstrations and BACM analyses before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes final BACT determinations for GVEA North Pole and Zehnder, it must include the determinations in Alaska's Serious SIP that then ultimately requires approval by EPA.[4] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented prior to June 9, 2021 - 4 years after reclassification.[5]

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM) consideration. MSMs will be a required element of the state implementation plan if the State applies for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

ADEC appreciates the cooperation that we've received from GVEA. ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

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[4] https://www.gpo.gov/fdsys/pkg/CFR-2013-title42-vol1/pdf/CFR-2013-title42-vol1-sec51-165.pdf
[5] 40 CFR 51.1010(a)

Sincerely,

Denise Koch, Director
Division of Air Quality

Enclosures:

September 10, 2018	ADEC Request for Additional Information for North Pole and Zehnder Facilities BACT Analyses
May 21, 2018	EPA Comments on ADEC Preliminary Draft Serious SIP Development Materials for the Fairbanks Serious PM-2.5 nonattainment Area
November 16, 2017	ADEC Request for Additional Information for North Pole and Zehnder BACT Analyses;
November 15, 2017	EPA GVEA BACT Analysis Review Comments
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for GVEA North Pole and Zehnder

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality
Jim Plosay, ADEC/ Air Quality
Aaron Simpson, ADEC/Air Quality
Naomi Knight/GVEA
Tim Hamlin, EPA Region 10
Dan Brown, EPA Region 10
Zach Hedgpeth, EPA Region 10

ADEC Request for Additional Information
Golden Valley Electric Association – North Pole and Zehnder Facilities
BACT Analysis Review
August 2017

September 10, 2018

Please address the following comments by providing the additional information identified by November 1, 2018. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public review. In order to provide this additional review opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public review period or based upon the new information provided in response to this information request.

This document does not represent a final BACT determination by ADEC. Please contact Aaron Simpson at aaron.simpson@alaska.gov with any questions regarding ADEC's comments.

1. Equipment Life – Page 31 of the North Pole analysis and Page 27 of the Zehnder analysis state "Because of the harsh climate, equipment in this far north location experiences more wear and tear than equipment in moderate climates. On this basis, a ten year return on the [water injection and] SCR system is assumed to be reasonable." This same assumption is made for the other control devices. ADEC identified that the EPA Air Pollution Control Cost Manual[1] uses a hypothetical example that assumes the control equipment has a useful life of ten years. However the cost analyses must use a reasonable estimate of the actual life of the control equipment for each control technology. In order to use an equipment life that is shorter than 30 years, evidence must be provided to support the claim that 10 years is a reasonable timeframe for equipment life. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as turbines.

2. BACT limits – BACT limits by definition, are numerical emission limits. However regulation allows a design, equipment, or work/operational practices if technological or economic limitations make a measurement methodology infeasible. Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for pollutant for each emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. Measures to minimize the occurrence of these periods, or to minimize emissions during these periods are control options. Combinations of steady-state control options and SSM control options can be combined to create distinct control strategies. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

[1] U.S. EPA OAQPS Air Pollution Control Cost Manual, 6th Edition [EPA/452/B-02-001]

3. Cost Analyses – Page 44 of the North Pole analysis indicates that EUs 1 and 2 have historically low run hours. Page 34 of the Zehnder analysis state that "GVEA believes that an economic analysis based on the actual emissions and operations of these turbines is more relevant for purposes of determining viable ways to reduce PM2.5 ambient concentrations in the Fairbanks area." However, all BACT cost effectiveness calculations must be based upon the potential to emit, and not on historic operation. Please update the cost analyses using the unrestricted potential to emit for each of the emissions units or propose operational limits (including control efficiencies associated with limited operation). Additionally, see Comments 4, 5, and 6 for additional information related to retrofit costs, baseline emissions, and factor of safety.
4. Retrofit Costs – EPA's Control Cost Manual indicates that study-level cost estimates (± 30 percent) should not include a retrofit factor greater than 30 percent, so detailed cost estimates (± 5 percent) are required for higher factors. High retrofit cost factors (50 percent or more) may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement). Provide detailed cost analyses and justification for any difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analyses.
5. Baseline Emissions – Include the baseline emissions for all emission units included in the analyses. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). NSPS and NESHAP requirements are not considered in calculating the baseline emissions. The baseline is usually the legal limit that would exist, but for the BACT determination. Baseline takes into account the effect of equipment that is part of the design of the unit (e.g., water injection and low NOx burners) because they are considered integral components to the unit's design. If the uncontrolled emission rate is 'soft,' run the cost effectiveness calculations using two or three different baselines.
6. Factor of Safety – If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.
7. Good Combustion Practices –For each emission unit type (oil fuel-fired turbines, combined cycle turbines, emergency generator engines, and boilers) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices. Include any work or operational practices that will be implemented and describe how continuous compliance with good combustion practices will be achieved.
8. Control Technology Availability – For the North Pole Facility, include Flue Gas Recirculation in the review of NOx control technologies for diesel-fired boilers. Rank the control technologies by efficiency (specify % control). Select the best performing control technology as BACT or provide specific energy, environmental, and economic impacts and other costs justification for why each better performing control technology was not selected instead of good combustion practices. Provide a numerical NOx emission limit for the diesel-fired boilers or identify the work or operational practices that will be utilized to ensure compliance with proposed limits.
9. Alternative Fuel Costs – Please provide a cost analysis for SO_2 emissions reductions for switching from current No. 2 diesel fuel to low sulfur diesel with a sulfur fuel content of 0.05 percent by weight. Also provide a cost analysis for a switch from No. 2 diesel fuel to No. 1 diesel fuel.

10. Interest Rate – All cost analyses must use the current bank prime interest rate. This can be found online at https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table). Please revise the cost analyses as appropriate.
11. Conversion to Natural Gas – For any emission units capable of converting to natural gas combustion (with the requisite changes to the burners, etc.), evaluate the commercial availability of converting to natural gas. For example, GVEA has stated the combustion turbines at its North Pole Expansion Power Plant have the ability to burn natural gas, and the IGU has indicated the intent to expand the supply of natural gas to Fairbanks and North Pole.

Attachment: EPA comments on ADEC Preliminary Draft Serious SIP Development materials for the Fairbanks serious $PM_{2.5}$ nonattainment area

General

The attached comments are intended to provide guidance on the preliminary drafts of SIP documents in development by ADEC. We expect that there will be further opportunities to review the more complete versions of the drafts and intend to provide more detailed comments at that point

1. Statutory Requirements - This preliminary draft does not address all statutory requirements laid out in Title I, Part D of the Clean Air Act or 40 C.F.R. Part 51, Subpart Z. The submitted Serious Area SIP will need to address all statutory and regulatory requirements as identified in Title I, Part D of the Clean Air Act, 40 C.F.R. Part 51, Subpart Z, the August 24, 2016 $PM_{2.5}$ SIP Requirements Rules (81 FR 58010, also referred to at the $PM_{2.5}$ Implementation Rule), and any associated guidance.

   In the preliminary drafts, notable missing elements included: Reasonable Further Progress, Quantitative Milestones, and Conformity. This is not an exhaustive list of required elements.

   The NNSR program is a required element for the serious area SIP. We understand ADEC recently adopted rule changes to address the nonattainment new source review element of the Serious SIP, and that ADEC plans to submit them to the EPA separately in October 2018. Thank you for your work on this important plan element.

2. Extension Request - This preliminary draft does not address the decision to request an attainment date extension and the associated impracticability demonstration. On September 15, 2017, ADEC sent a letter notifying the EPA that it intends to apply for an extension of the attainment date for the Fairbanks $PM_{2.5}$ Serious nonattainment area. The Serious Area SIP submitted to EPA will need to include both an extension request and an impracticability demonstration that meet the requirements of Clean Air Act section 188(e). In order to process an extension request, the EPA requests timely submittal of your Serious Area SIP to allow for sufficient time to review and take action prior to the current December 2019 attainment date, so as to allow, if approvable, the extension of the attainment date as requested/appropriate. For additional guidance, please refer to 81 FR 58096.

3. Split Request - We support the ADEC and the FNSB's decision to suspend their request to the EPA to split the nonattainment area. We support the effort to site a monitor in the Fairbanks area that is more representative of neighborhood conditions and thus more protective of community health. This would provide additional information on progress towards achieving clean air throughout the nonattainment area.

4. BACM (and BACT), and MSM - Best Available Control Measures (including Best Available Control Technologies) and Most Stringent Measures are evaluative processes inclusive of steps to identify, adopt, and implement control measures. Their definitions are found in 51.1000, 51.1010(a).

All source categories, point sources – area sources – on-road sources – non-road sources, need to be evaluated for BACM/BACT and MSM. De minimis or minimal contribution are not an allowable rationale for not evaluating or selecting a control measure or technology.

The process for identifying and adopting MSM is separate from, yet builds upon, the process of selecting BACM. Given that Alaska is intent on applying for an extension to the attainment date, Alaska must identify BACM and MSM for all source categories. These processes are described in 51.1010(a) and 51.1010(b) and in the $PM_{2.5}$ Implementation Rule preamble at 81 FR 58080 and 58096. We further discuss this process in the "BACM (and BACT), MSM" section that starts on page 3 below.

5. Resources and Implementation - The serious area $PM_{2.5}$ attainment plan will be best able to achieves its objectives when all components of the SIP, both the ADEC statewide and FNSB local measures, are sufficiently funded and fully implemented.

6. Use of Consultants- For the purpose of clarity, it will be important to identify that while contractors are providing support to ADEC, all analyses are the responsibility of the State.

Emissions Inventory

1. Extension Request Emission Inventories - Emissions inventories associated with the attainment date extension request will need to be developed and submitted. Table 1 of the Emissions Inventory document is one example where the submittal will need to include the additional emissions inventories, including RFP inventories, extension year inventories for planning and modeling, and attainment year planning and modeling inventories, associated with the attainment date extension request.

2. Modeling Requirements - Related to emissions inventory requirements, the serious area SIP will need to model and inventory 2023 and 2024, at minimum. We recommend starting at 2024 and modeling earlier and earlier until there is a year where attainment is not possible. That would satisfy the requirement that attainment be reached as soon as practicable.

3. Condensable Emissions - All emissions inventories and any associated planning, such as Reasonable Further Progress schedules, need to include condensable emissions as a separate column or line item, where available. Where condensable emissions are not available separately, provide condensable emissions as included (and noted as such) in the total number. The following are examples of where this would need to be incorporated in to the Emissions Inventory document:
    a. Page 20, paragraph 5 (or 2nd from the bottom).
    b. Page 34, Table 8. Include templates.

Precursor Demonstration

1. Ammonia Precursor Demonstration - The draft Concepts and Approaches document, Table 4 on page 9, states that a precursor demonstration was completed for ammonia and that the result was "Not significant for either point sources or comprehensively." The Precursor Demonstration chapter does not include an analysis for ammonia. Please include the precursor demonstration for ammonia in the Serious Plan or amend this table.

2. Sulfur Dioxide Precursor Description - The draft Concepts and Approaches document, Table 4 on page 9, states that sulfur dioxide was found to be significant. All precursors are presumptively considered significant by default and the precursor demonstration can only show that controls on a precursor are not required for attainment. Suggested language is, "No precursor demonstration possible."

BACM (and BACT), MSM

Overall

The EPA appreciates ADECs efforts to identify and evaluate BACM for eventual incorporation into the Serious Area SIP. The documents clearly display significant effort on the part of the state and are a good first step in the SIP development process. In particular, we are supportive of ADECs efforts to evaluate BACT for the major stationary sources in the nonattainment area, as control of these sources is required by the CAA and $PM_{2.5}$ SIP Requirements Rule.

1. BACM/BACT and MSM: Separate Analyses - The "Possible Concepts and Potential Approaches" document appears to conflate the terms BACM/BACT and MSM, as well as, the analyses for determining BACM/BACT and MSM. BACM and MSM have separate definitions in 40 CFR 51.1000. By extension, the processes for selecting BACM and MSM are laid out separately in the $PM_{2.5}$ SIP Requirements Rule (compare 40 CFR 51.1010(a) for BACM and 40 CFR 51.1010(b) for MSM). Accordingly, the serious area SIP submission will need to have both a BACM/BACT analysis and an MSM analysis. We believe that there is flexibility in how these analyses can be presented, so long as the submission clearly satisfies the requirements of both evaluations, methodologies, and findings.

2. Selection of Measures and Technologies - The CAA and the $PM_{2.5}$ SIP Requirements Rule requires that ***all*** available control measures and technologies that meet the BACM (including BACT) and MSM criteria need to be implemented. All source categories need to be evaluated including: point sources (including non-major sources), area sources, on-road sources, and non-road sources.

3. Technological Feasibility - All available control measures and technologies include those that have been implemented in nonattainment areas or attainment areas, or those potential measures and technologies that are available or new but not yet implemented. Similarly, Alaska may not automatically eliminate a particular control measure because other sources or nonattainment areas have not implemented the measure. The regulations do not have a quantitative limit on number of controls that should be implemented.

For technological feasibility, a state may consider factors including local circumstances, the condition and extent of needed infrastructure, or population size or workforce type and habits, which may prohibit certain potential control measures from being implementable. However, in the instance where a given control measure has been applied in another NAAQS nonattainment area, the state will need to provide a detailed justification for rejecting any potential BACM or MSM measure as technologically infeasible (81 FR 58085).

A Borough referendum prohibiting regulation of home heating would not be an acceptable consideration to render potential measures technologically infeasible. The State would be responsible for implementing the regulations in the case that the Borough was not able. We believe that the most efficient path to clean air in the Borough is through a local, community effort.

4. Economic Feasibility - The BACM (including BACT) and MSM analyses need to identify the basis for determining economic feasibility for both the BACM and MSM analyses. In general, the $PM_{2.5}$ SIP Requirements Rule requires the state apply more stringent criteria for determining the feasibility of potential MSM than that used to determine the feasibility of BACM and BACT, including consideration of higher cost/ton values as cost effective.

5. Timing - The evaluations will need to identify the time for selection, adoption, and implementation for all measures. BACT must be selected, adopted, and implemented no later than 4 years after reclassification (June 2021). MSM must be selected, adopted, and implemented no later than 1 year prior to the potentially extended attainment date (December 2023 at latest). The RFP section of the serious area plan will need to identify the BACM and MSM control measures, their time of implementation, and the time(s) of expected emissions reductions. Timing delays in selection, adoption, implementation are not considered for BACM and MSM.

   As mentioned in the comment above in the "General" comment section, there are three criteria distinguishing between BACM and MSM, not one.

BACM - General

1. BACM definition, evaluations - The definition of BACM at 40 CFR 51.1000 describes BACM as any measure "that generally can achieve greater permanent and enforceable emissions reductions in direct $PM_{2.5}$ and/or $PM_{2.5}$ plan precursors from sources in the area than can be achieved through the implementation of RACM on the same sources." We believe that potential measures that are no more stringent than existing measures already implemented in FNSB, those that do not provide additional direct $PM_{2.5}$ and/or $PM_{2.5}$ precursors emissions reductions, do not meet the definition of BACM. These would need to be evaluated in the BACM and MSM analysis.

   For measures that are currently being implemented in Fairbanks that provide equivalent or more stringent control, we recommend identifying the ADEC or Borough implemented measure as part of the BACM control strategy. These implemented measures should be listed in their BACM findings at the end of the document. This comment applies to all of the

measures that were screened out from consideration due to not being more stringent than the already implemented measure.

The analyses for a number of measures (e.g., Measure 30, Distribution of Curtailment Program information at time of woodstove sale) conclude that the emission reductions would be insignificant and difficult to quantify and, therefore, the measure is not technologically feasible. These measures may be technologically feasible. However, if existing measures constitute a higher level of control or if implementation of the measures is economically infeasible those would be valid conclusions if properly documented. De minimis or minimal contribution is not a valid rationale for not considering or selecting a control measure or technology.

The conclusion "not eligible for consideration as BACM" is not valid as all assessments for BACM and MSM are part of the evaluation. More appropriate conclusions could include that existing measures qualify as BACM or MSM, or are more stringent. Additional conclusions could include that evaluated measures were not technologically feasible, economically feasible, or could not practically be adopted and implemented prior to the required timeframe for BACM or MSM.

2. BACM and MSM, Ammonia - In the Approaches and Concepts document, Table 5 references that there are no applicable control measures or technologies for the $PM_{2.5}$ precursor ammonia. No information to substantiate this claim are found in the preliminary draft documents. Unless NH_3 is demonstrated to be insignificant for this area, the serious area plan will need to include an evaluation of NH_3 and potential controls for all source categories including points sources.

3. Backsliding Potential - When benchmarking the BACM and MSM analyses for stringency, ensure that the evaluation is based on the measures approved into the current Moderate SIP. This will relate primarily to the current ADEC/FNSB curtailment program but also other related rules. Many wood smoke control measures are interrelated, and changes to those measures may affect determinations on stringency of directly related and indirectly related measures. Examples of this can be found in multiple measures including, but not limited to Measures 5, 7, and 16.

4. Transportation Control Measures - The Approaches and Concepts document, on Page 13, states that the MOVES2014 model does not estimate a PM benefit as a result of an I/M program, and therefore the I/M is not technologically feasible. This is not a valid conclusion given that the Fairbanks area operated an I/M program to reduce carbon monoxide and the Utah Cache Valley nonattainment areas has an I/M program for VOC control. This measure will need to be evaluated. Referring to the 110(l) analysis for the Fairbanks CO I/M program may provide insight into how to quantify the emissions associated with an I/M program.

With regard to control measures related to on-road sources, we have received inquiries from the community regarding idling vehicles and further evaluation emission benefits would be responsive to citizen concern and may provide additional air quality benefit.

BACM - Specific Measures

- Measure 16, page 34-35. Date certain Removal of Uncertified Devices. The "date certain" removal of uncertified woodstoves in Tacoma, Washington appears more stringent than the current Moderate SIP approved Fairbanks ordinance in terms of the regulation and in practice. While the current ordinance appears to provide similar protection during stage 1 alerts, this is dependent on 100% compliance and the curtailment program remaining in its current form. Removal of uncertified stoves guarantees reductions in emissions in the airshed during both the curtailment periods and throughout the heating season. The information provided does not support the conclusion that the Fairbanks controls provides equivalent or more stringent control. Date certain removal of uncertified wood stoves needs to be considered for the area.

  Measures R4, R9, and R12, page 64, 68 and 71. These measures do not reference the Puget Sound Clean Air Agency (Section 13.07) requirement for removal of all uncertified stoves by September 30, 2015. This is equivalent to having all solid fuel burning appliances be certified and would be more stringent than the current SIP approved rules in Fairbanks. We believe that these measures need to be evaluated in the BACM and MSM analyses.

  Measure R4 and R9, page 64 and 68. All Wood Stoves Must be Certified. These measure should be evaluated.

- Measure 19-20 and 25, page 36-38 and 39. Renewal and Inspection Requirements. ADEC has not adequately demonstrated their conclusion that Fairbanks has a more stringent measure than Missoula and San Joaquin. We believe that the renewal requirements and inspection/maintenance requirements associated with the Missoula alert permits and San Joaquin registrations allows the local air agency an opportunity to verify on a regular basis that the device operates properly over times. Wood burning appliances require regular maintenance in order to achieve the certified emissions ratings. The FNSB Stage 1 waivers do not have an expiration and do not have an inspection and maintenance component making it less stringent.

- Measure 31, page 43. While the Borough has SIP approved dry wood requirements that prohibit the burning of wet wood and moisture disclosure requirements by sellers, we believe that a measure limiting the sale of wet wood during the winter months should be further analyzed for BACM (and MSM) consideration.

- Measures 33, 35, 36, 37, 43. Multiple Measures identify that recreational fires have been exempted from existing regulations. Small unregulated recreational fires, bonfires, fire pits,

and warming fires have the potential to contribute emissions during a curtailment period. The FNSB and ADEC regulations should be re-evaluated for removing this exclusion.

- Measure 49, page 58. Ban on Coal Burning. We believe the regulations in Telluride are more stringent than in Fairbanks. Telluride prohibits coal burning all year whereas in Fairbanks an existing coal stove can burn when there is no curtailment which could contribute additional emissions to the airshed, especially during poor conditions when a curtailment may not have been called. We do not agree with the conclusion that the PM_{10} controls are ineligible for consideration for control of $PM_{2.5}$.

- Measure R20, page 76. Transportation Control Measures related to Vehicle Idling. We have received multiple inquiries regarding community interest in controlling emissions from idling vehicles. These types of control measures should be further evaluated in the BACM and MSM analyses.

- Measure 1, page 79-81. Surcharge on Solid Fuel Burning Appliances. For purposes of implementing an effective program to reduce $PM_{2.5}$ in the Borough we believe that a surcharge may be a helpful way to supplement limited funds. Implementation efforts within the nonattainment area could benefit from $24,000 of additional funding whether used for a code enforcer or other support of the wood smoke programs.

- Additional controls that should be further evaluated for BACM and MSM include:
    - Measure R1, page 63: Natural gas fired kiln or regional kiln.
    - Measure R12, page 71: Replace uncertified stoves in rental units.
    - Measure R17, page 75: Ban use of wood stoves
    - Measure R6, page 65: Remove Hydronic Heaters at Time of Home Sale & Date certain removal of Hydronic heaters. We suggest evaluating these measures at the state and local level.
    - Weatherization / heat retention programs should be evaluated. These should be evaluated for existing homes through energy audits and increasing insulation and energy efficiency. For new construction, building codes (Fairbanks Energy Code) should be evaluated with reference to the IECC Compliance Guide for Homes in Alaska http://insulationinstitute.org/wp-content/uploads/2015/12/AK_2009.pdf, and the DOE R-value recommendations, http://www.fairbanksalaska.us/wp-content/uploads/2011/07/ENERGY-CODE.pdf. (Note: More recent information may be available.)
    - Fuel oil boiler upgrades / operation & maintenance programs should be evaluated.

BACM - Ultra-Low Sulfur Fuel

1. Incomplete Analysis - The report findings provide analysis of the demand curve over a relatively short (12 month) time frame. This analysis appears to be based on a partial equilibrium model. This is a misleading time frame given the volatility of demand side fuel oil pricing. Also, in order to determine the equilibrium price, the analysis must also analyze

the supply curve. The report does not include information about the future supply side costs but needs to in order to make conclusions about the cost to the community of ultra-low sulfur heating oil.

2. Analysis of Increased Supply, Consumption - The report does not address future change in the market nor potential economies of scale to be achieved by an increase in ultra-low sulfur fuel consumption. Page 3 of the report identifies that, "the additional premium to purchase ULS over HS, decreased significantly since 2008-2010. It is likely that, this can be attributed to increased ULS capacity." We believe that the report should further explore the supply side costs.

3. Supply Cost Analysis - A supply side cost analysis is necessary to better understand the cost to the supplier to produce and provide ULS heating fuel. The BACM analysis must start with a transparent and detailed economic analysis of exclusively supplying ultra-low sulfur heating oil to the nonattainment area.

4. BACM Assessment - The current analysis does not provide information needed to assess BACM economic feasibility. The report should analyze the total cost to industry of delivering ultra-low sulfur heating oil to the entire community in terms of standard BACM metrics, $/ton.

BACT

General Comments

At this time, EPA is providing general comments based on review of the draft BACT analyses prepared by ADEC as well as addressing certain issues discussed in earlier BACT comments provided by EPA. Detailed comments regarding each individual analysis are not being provided at this time. While EPA appreciates the time and effort invested by ADEC staff in preparing the draft BACT analyses, the basic cost and technical feasibility information needed to form the basis for retrofit BACT analyses at the specific facilities has not been prepared. In other words, analyses which are adequate to guide decision making regarding control technology decisions for these rather complex retrofit projects cannot be prepared without site specific evaluation of capital control equipment purchase and installation costs, and site specific evaluation of retrofit considerations. EPA will conduct a thorough review of any future BACT or MSM analyses which are prepared based on adequate site specific information, and will provide detailed comments relative to each emission unit and pollutant at that time.

1. Level of Analysis – The analyses are presented as "preliminary BACT/MSM analyses" on the website, but the documents themselves are titled only as BACT analyses and the conclusions only reflect BACT. Additionally, the determinations may not be stringent enough to be considered BACT given that better performing SO_2 control technologies have not been adequately analyzed. These analyses cannot be considered to provide sufficient basis to support a selection of MSM.
2. Site-Specific Quotes Needed – The cost analyses, particularly for SO_2 control technologies, must be based on emission unit-specific quotes for capital equipment purchase and

installation costs at each facility. These are retrofit projects which must be considered individually in order to obtain reliable study/budget level (+/- 30%) cost estimates which are appropriate to use as the basis for decision making in determining BACT and potentially MSM. EPA believes that control decisions of this magnitude justify the relatively small expense of obtaining site-specific quotes.

3. SO_2 Control Technologies – The analyses must include evaluation of circulating dry scrubber (CDS) SO_2 control technology. This demonstrated technology can achieve SO_2 removal rates comparable to wet flue gas desulfurization (FGD) at lower capital and annual costs, and is more amenable to smaller units and retrofits. Modular units are available.
4. Control Equipment Lifetime – The analyses must use reasonable values for control equipment lifetime, according to the EPA control cost manual (EPA CCM). EPA believes that the following equipment lifetimes reflect reasonable assumptions for purposes of the cost analysis for each technology as stated in the EPA control cost manual and other EPA technical support documents. Use of shorter lifetimes for purposes of the cost analysis must include evidence to support the proposed shortened lifetime. One example where EPA agrees a shortened lifetime is appropriate would be where the subject emission unit has a federally enforceable shutdown date. Certain analyses submitted in the past have claimed shortened equipment lifetimes based on the harshness of the climate in Fairbanks. In order to use an equipment life that is shortened based on the harsh climate, evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers. Lacking adequate justification, all cost analyses must use the following values for control equipment lifetime:
    a. SCR, Wet FGD, DSI, CDS, SDA – 30 years
    b. SNCR – 20 years
5. Availability of Control Technologies – Technologically feasible control technologies may only be eliminated based on lack of availability if the analysis includes documented information from multiple control equipment vendors (who provide the technology in question) which confirms the technology cannot be available within the appropriate implementation timeline for the emission unit in question.
6. Assumptions and Supporting Documents – All documents cited in the analyses which form the basis for costs used and assumptions made in the analyses must be provided. Assumptions made in the analyses must be reasonable and appropriate for the control technologies included in the cost analysis.
7. Interest Rate – All cost analyses must use the current bank prime interest rate according to the revised EPA CCM. As of May 10, 2018, this rate is 4.75%. See https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table).
8. Space Constraints – In order to establish a control technology as not technologically feasible due to space constraints or other retrofit considerations, detailed site specific information must be submitted in order to establish the basis for such a determination, including detailed drawings, site plans and other information to substantiate the claim.
9. Retrofit Factors – All factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor or whether installation of a specific control technology is technologically infeasible. EPA Region 10

believes that installation factors which would complicate the retrofit installation of the control technology should be evaluated by a qualified control equipment vendor and be reflected in a site-specific capital equipment purchase and installation quote. Lacking site-specific cost information, all factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor. One example of the many retrofit considerations that must be evaluated is the footprint required for each control technology. A vendor providing a wet scrubber will be able to estimate the physical space required for the technology, and evaluate the existing process equipment configuration and available space at each subject facility. The determination of whether a specific control technology is feasible and what the costs will be may be different at each facility based on this and other factors. Site-specific evaluation of these factors must be conducted in order to provide a reasonable basis for decision making.

10. Control Efficiency – Cost effectiveness calculations for each control technology must be based on a reasonable and demonstrated high end control efficiency achievable by the technology in question at other emission units, or as stated in writing by a control equipment vendor. If a lower pollutant removal efficiency is used as the basis for the analysis, detailed technical justification must be provided. For example, the ability of SCR to achieve over 90% NO_X reduction is well established, yet the ADEC draft analyses assume only 80% control. Use of this lower control efficiency requires robust technical justification.
11. Condensable Particulate Matter – Although the existing control technology on the coal fired boilers may be evaluated as to whether it meets the requirement for BACT for particulate matter, baghouses primarily reduce emissions of filterable particulate matter rather than condensable PM. Given that all condensable PM emitted by the coal fired boilers would be classified as $PM_{2.5}$, the BACT analyses must include consideration of control options for these emissions. Where control technologies evaluated for control of other pollutants may provide a collateral benefit in reducing emissions of $PM_{2.5}$, this should be evaluated as well.
12. Guidance Reference – The steps followed to perform the BACT analysis mentioned in section 2 are from draft NSR/PSD guidance. The correct reference should be 81 FR 58080, 8/24/2016. As a result of this, some of the steps outlined in the BACT analysis need to be updated.
13. Community Burden Estimate – The concepts and approaches document labels capital purchase and installation costs for air pollution control technology at the major source facilities as "community burden" (see Tables 7 and 8, pages 10-11). EPA believes it is important to properly label the cost numbers being used as capital purchase and installation costs, since presenting them as community burden appears to attribute the entire initial capital investment for the various control technologies to the community in a single year, and also ignores annual operation and maintenance costs. As described in the EPA CCM, the cost methodology used by EPA for determining the cost effectiveness of air pollution control technology amortizes the initial capital investment over the expected life of the control device, and includes expected annual operating and maintenance expenses. EPA believes presentation of this annualized cost over the life of the control technology more accurately represents the actual cost incurred and is consistent with how cost effectiveness is estimated in the context of a BACT analysis.
14. Conversion to Natural Gas – For any emission units capable of converting to natural gas combustion (with the requisite changes to the burners, etc), the MSM analysis in particular

should thoroughly evaluate the feasibility of this option. For example, GVEA has stated the combustion turbines at its North Pole Expansion Power Plant have the ability to burn natural gas, and the IGU has indicated the intent to expand the supply of natural gas to Fairbanks and North Pole.

APPENDIX:

Additional Comments and Suggestions

Possible Concepts and Potential Approaches

Throughout all SIP documents references to design values should include a footnote to the source of the information (e.g., "downloaded from AQS on XX/XX/XXX" or "downloaded from [state system] on XX/XX/XXXX") and how exceptional events were treated.

We suggest referencing the August 24, 2016 81 FR 58010 Fine Particulate Matter NAAQS: State Implementation Plan Requirements rule with one consistent term. We suggest the 2016 $PM_{2.5}$ Implementation Rule.

Page 4, Figure 1. The comparative degree days and heating related information is better suited for the sections evaluating BACM and economic feasibility. If intending on using this information to differentiate Fairbanks from other cold climates and/or nonattainment areas, depicting comparative home heating costs would be more supportive.

Page 4, Table 1. The design values in the table and in the discussion need to be updated for 2015-2017.

Page 6-7: The "Totals" row in Table 3 (non-attainment areas emissions by source sector) does not appear to be the sum of the individual source sector emissions.

Page 7: The statement about FNSB experiencing high heating energy demand per square foot needs to be referenced.

Page 7: The discussion of Eielson AFB growth needs a reference to the final EIS.

Page 9: Table 4's title should be changed to "Preliminary Precursor Demonstration Summary"

Page 9: Table 4 includes a column "Modeling Assessment". Not all precursors were assessed with modeling, and modeling is just one tool for the precursor demonstration. A suggestion for the column title is "Result of Precursor Demonstration."

Page 9: Table 5's title should be changed to "Preliminary BACT Summary." Table 5 also needs to update the title to reference "Precursor Demonstration" as the term "Precursor Significance Evaluation" is the incorrect terminology for this analysis.

Page 10: ADEC's proposal to only require one control measure per major stationary source to meet BACT and MSM for SO_2, is not consistent with the Act or rule. As discussed above, BACM and MSM have separate definitions in 40 CFR 51.1000. By extension, the processes for

selecting BACM and MSM are laid out separately in the PM2.5 SIP Requirements Rule (compare 40 CFR 51.1010(a) for BACM and 40 CFR 51.1010(b) for MSM).

Page 10: Table 6 should identify the specific dry sorbent injection selected as BACT.

Page 11: Suggest changing “less sources” to “fewer sources.”

Page 13: The statement about an I/M program providing PM benefit needs to be clarified. Is this referring just to NOx and VOC precursor contribution to PM2.5, or also direct PM2.5 benefits?

Page 14: The statement “ADEC interprets the main difference between BACT/BACM and MSM as the time it takes to implement a control” is inaccurate. As discussed above, although the rule sets our different schedules for implementation of MSM and BACM, this is not the only major difference between those concepts. Notably, the rule contemplates a higher stringency for MSM as well as a higher cost/ton threshold for determining economic feasibility of the measure.

Technical Analysis Protocol

Page 2: The design values at the top of the page need to be updated to 2015-2017.

Page 2: Recommend removing the sentence “This site will be included in the Serious SIP’s attainment plan…” as the North Pole Elementary will be involved in the redesignation to attainment in the sense that all past and current monitoring data will be a part of an unmonitored area analysis to show that the entire area has attained the standard in addition to the regulatory monitor locations.

Page 2: Remove the discussion of the nonattainment area split.

Page 2: Paragraph 2, sentence 3 should refer to the unmonitored area analysis.

Page 2: The timeline described at the bottom of the page needs to be modified to reflect a current schedule. No projected year modeling was included in the preliminary draft documents. Control scenario modeling will likely not be completed in Q2 2018.

Page 3: We suggest a sentence overview of the unmonitored area analysis in Section 3.1.

Page 3: Section 3.2 needs to refer to the SPM data and how that will be used in the Serious Plan unmonitored area analysis. This section should discuss current DEC efforts to site a new monitor in Fairbanks.

Page 3: Section 3.4 needs to describe the CMAQ domain in addition to the WRF domain. A figure (map) would help.

Page 4: Section 3.5 needs a more developed discussion of the WRF assessment, including describing the criteria that were used to assess the state-of-the-art, what the current version is, and what version was used.

Page 4: Section 3.6 needs to reference all emission inventories in development, including potential attainment date extension years and RFP years.

Page 4: In Section 4.1, the statement about the Moderate SIP covering the relevant monitors for the Serious SIP is inaccurate. The statement needs to qualify whether it is referring to regulatory monitors or non-regulatory monitors. In addition, the North Pole Fire Station, NCore, and North Pole Elementary monitors were not included in the Moderate SIP.

Page 5: Table 4.1-1's title suggests that all SPM sites are listed, but only sites with regulatory monitors are listed. Please list all the SPM sites used in the unmonitored area analysis in a separate table and modify this title of Table 4.1-1 to reflect that it lists sites that are regulatory.

Page 5: North Pole Elementary was a regulatory site for a part of the baseline period and was NAAQS comparable. Table 4.1-1 needs to be updated.

Page 8: Table 4.2-1 should be updated to include 2011-2017 98^{th} percentiles. Table 4.2-2 should be updated to include 3-year design values for 2013-2017. For clarity, we recommend the 3-year design values include the full period in order to better distinguish from Table 4.2-1. For instance, "2013" would be "2011-2013".

Page 8: The statement starting, "a clear indication…" needs to be amended or removed. It is inaccurate. The prevalence of organic carbon does not indicate the dominance of wood burning, much less a clear indication. Many sources in Fairbanks emit organic carbon.

Page 8: The statement starting "The concentration share…" need to be amended or removed. Suggest removing "drastically". There is no scientific definition of a drastic change in percentages of $PM_{2.5}$ species, nor does the different 56% to 80% appear "drastic."

Page 9: The detailed description of the Simpson and Nattinger analysis does not reflect that SANDWICH process and it is preliminary data. It should be included within the body of the Serious Plan appendix on monitoring, but is out of place in a summary TAP.

Page 9: there are two different tables with the same table number (Table 4.3-1).

Page 10: Please clarify Table 4.4-1. This appears to be the design value calculation for the 5-year baseline design value, 2011-2015. If correct, then please label the 3-year design values according to the three years (e.g., "2011-2013"), clarify the table heading as being the "Five Year Baseline Design Value, 2011-2015 (µg/m3)", and clarify that the last column is the 5 Year Baseline Design Value associated with the table heading.

Page 11: At the end of section 5, please refer to the emission inventory chapter's meteorological discussion of the episodes.

Page 11: Section 6 needs to justify the extent, resolution, and vertical layer structure of the CMAQ domain (and the WRF domain) or refer to where that is included in the Moderate Plan.

Page 13: We suggest changing "PMNAA" to "NAA" to be consistent with the EI chapter.

Page 15, Section 8.1: There needs to be mention of how the F-35 deployment will be considered, with a reference to the final EIS.

Page 15-19: section 8.2-8.6 use the future tense for tasks that have been completed and are inconsistent with the schedule at the beginning of the TAP. Please adjust based on current status.

Page 20, section 9.2 states that "a BACT analysis is an evaluation of all technically available control technologies for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts." This sentence should be revised to reflect that the technological feasibility assessment occurs after identification of all potential control measures for each source and source category.

Page 20, section 9.3 the second sentence should read: "BACM measures found to be economically infeasible for BACM *must* be analyzed for MSM."

Page 21: Section 10.1 needs to be updated to reflect the current CMAQ version (5.2.1) and a discussion of why that model has not been used.

Page 21: Suggest sentence starting "There will be a gap…" be changed to "There is a gap in terms of assessing the performance at the North Pole Fire Station monitor for the Serious Plan because the State Office Building in Fairbanks was the only regulatory monitor at the time of the 2008 base case modeling episodes."

Page 23: Please explain the solid and dashed lines in the soccer plot.

Page 23: Please be sure to include a full discussion of North Pole performance in this section. Even though we lack measurements, we can discuss the ratio of the modeling results at NPFS versus SOB versus that ratio from more recent monitoring data (2011-2015 baseline design value period).

Page 23: Please clarify what is meant by "Moderate Area SIP requirements."

Page 24: The discussion of the 2013 base year discusses representative meteorological conditions without describing what the representative meteorological conditions are for high $PM_{2.5}$. Please reference the discussion of representative meteorological conditions that will be found elsewhere in the SIP.

Page 24: The discussion of the modeling years needs to be consistent and reflect the extension request past 2019. The attainment year cannot be earlier than 2019. Each extension year must be individually requested. For modeling efficiency, we recommend starting with 2024. If that year attains, then 2023 and so on until we have one year that attains and the year before that does not. This should give us the information about what is the earliest year for attainment.

Page 25: We suggest changing "modeling design value" to "design value for modeling"

Page 26: Please clarify the "SMAT" label in the tables. They may be the SANDWICH concentrations and the "5-yr DV" rows are the SMAT concentrations. Please clarify the units in the rows.

Emission Inventory

Clarification – In the EI document we would like to understand the functional difference between the base year, and baseline year

Please identify the methodology for generating ammonia and condensable PM emissions numbers.

Page 1: Please be consistent in “emission inventory” versus “emissions inventory”.

Page 1: “CAA” to “Clean Air Act” for clarity

Page 3: It would be helpful to refer to 172(c)(3) in Section 1.2, bullet 1 as the planning and reporting requirements.

Page 5: Please include extension years and RFP years in Table 1’s calendar years similar to what was done for Table 2. There should be one RFP projected inventory and QM beyond the extended attainment date. It would be helpful to include basic information about extension years and RFP years to better foreshadow Table 2.

Page 7: Please clarify the “winter season” inventory as the “seasonal” inventory that represents the daily average emissions across the baseline episodes.

Page 7, paragraph 1. Please include reference documentation for the following statement, “results in extremely high heating energy demand per square foot experienced in no other location in the lower-48.”

Page 9: Please change “Violations” to “Exceedances.” Exceedance is the term for concentrations over the standard. Violations is the term for dv over the standard.

Page 9: Add “No exceedances were recorded outside the months tabulated in Table 3 that were not otherwise flagged by Alaska DEC as Exceptional Events.”, to the end of the last paragraph on the page.

Page 13: Please clarify the provenance of the BAM data (e.g., “downloaded from [state database or AQS] on XX/XX/XXXX). In particular, it is important to note if the data has been calibrated to the regulatory measurement (aka, corrected BAM).

Page 17-18. Sentence Unclear “For example, a planning inventory based on average daily emissions across the entire six-month nonattainment season will likely reflect a relatively lower fraction of wood use-based space heating emissions than one based on the modeling episode day average since wood use for space heating Fairbanks tends to occur as a secondary heating source on top of a “base” demand typically met by cleaner home heating oil when ambient temperatures get colder.”

Page 19: Remove “Where appropriate,”. All source sectors should be re-inventoried for 2013, even if the emissions for the sector ends up being the same as in 2008.

Page 19: Change “projected forward” to “re-inventoried”, or similar wording. Reserve “project” for when the emission inventory is estimating emissions in a future year.

Page 20: Please refer to EPA’s memo on the use of MOVES2014a for the plug in adjustment. As a reminder, this information is sufficient only for development of the emissions inventory, not for SIP credit.

Page 20: Please submit the technical appendix referenced on page 20. When that is submitted, we expect to provide additional comment. To allow for review, we request expedited submission.

Page 21: At bottom of page, “project” should be “re-inventoried” or something that refers to an inventory produced after the fact.

Page 22, paragraph 1, Space heating area sources. Please further explain how the combined survey data best represents 2013 emissions.

Page 23: Add information about how NH_3 was inventoried for this category.

Page 23, 2nd paragraph from bottom. Facilities need to provide direct PM and all precursors, whether directly submitted or calculated from emissions factors.

Page 23, last paragraph.

- Potential typo – we believe that 2018 should be 2013.
- Question – Does scaling emissions cause any point source to exceed its PTE?

Page 25, bullet 3, Laboratory – Measured Emissions Factors for Fairbanks Heating Devices. The statement “first and most comprehensive systematic” would be more credible if simplified.

Page 27: Clarify how data from the 2014 NEI was modified to reflect emissions in 2013. Were they assumed to be the same between the two years? Or adjusted based on population change, or some other information?

Page 33: Please include information on how the Speciate database was used to develop the modeling inventory (and perhaps elsewhere for the planning inventory, if appropriate).

Precursor Demonstration

Throughout the Serious Area SIP we recommend using the terminology, Precursor Demonstration, to be consistent with the $PM_{2.5}$ Implementation Rule.

General: The overview of the nitrate chemistry is complicated. We suggest you combine the two discussions into one and organize it with the following logic:

1. Describe the two chemical environments: (1) daytime and (2) nighttime.
2. Describe the information that supports that daytime chemistry is not relevant here.
3. Describe the information that supports that nighttime chemistry is limited by excess NO.

4. Describe what happens if the entire emission inventory was increasing by a factor of 3.6 to get appropriate concentrations in the North Pole area. How does ammonium nitrate change?
5. Describe how increasing the emission inventory and then reducing all source sectors by 75% results in less of a reduction in $P_{M2.5}$ than reducing all source sectors by 75% in the original emission inventory.
6. NOTE: We are willing to provide a rough draft of this organization, if provided the original word document.

Title page: remove "com"

Page 2: Recommend using Section 188-190 instead of 7513-7513b.

Page 2: Recommend moving the last three sentences of the first paragraph to the end of the second paragraph.

Page 2: Please add "threshold" after 1.3 in the third paragraph.

Page 2: Please explain concentration-based and sensitivity-based before using the terms.

Page 2: Please add a footnote whether the numbers in the Executive Summary are SANDWICHed or not.

Page 3: Please change "has decided" to "decided."

Page 3: Make sure the concentrations listed for ammonia include ammonium sulfate and ammonium nitrate.

Page 5-7: The figure captions say that concentrations are presented but the images themselves have percentages. Please use concentrations for this analysis.

Page 9: The first paragraph says that the point sources are not responsible for the majority of sulfate at the monitors. Please substantiate that claim, or modify it.

Page 13: Please explain the relevance of referring to the VOC emissions of home heating in this summary of VOCs.

Page 14: Recommend adding "… and adjusted to reflect speciated concentrations for a total PM2.5 equal to the five year 2011-2015 design value" to the sentence that starts "The speciated PM2.5 data [were] analyzed.

Page 14: Please include the results of the concentration based analysis, perhaps as a table.

Page 14: Clarify that the concentration used for NH_3 is the ammonium sulfate and ammonium nitrate. See the draft EPA Precursor Demonstration Guidance.

Page 17: Recommend removing "slightly" and removing the sentence referring to rounding to the nearest tenth of a microgram.

Page 17-18: To help understand what is going on with the bounding run versus the normal run, it would be helpful to have the RRFs for the Modeled 75% scenario.

BACM

Page 9 and throughout: For clarity, please refer to the implementation rule as "$PM_{2.5}$" not "PM".

Page 14, Table 3. It would be helpful to include filter speciation data.

Page 16, Table 4: Please identify the RACM measures that were technologically and economically feasible but could not be implemented in the RACM timeline or note there were none.

Page 20 and 25, Table 6 and 7: For the final Table identifying the control measures evaluated, it would be helpful to identify the following: measure, cost/ton, BACM determination, MSM determination, and any additional comments.

Page 24: 12 measures were eliminated because they were determined to offer marginal or unquantifiable benefit. However, a measure may offer marginal benefit but may also cost very little. If there is another explanation for why these measures were not considered that follows the BACM steps, please include that in the Serious Area Plan.

Page 28: Stage 1 alerts are referred to multiple times including in Measure 2 on page 28 and Measure 33, pg 47 and pg 48. Please clarify in these analyses whether the measure applies during all stages of alerts and the associated level of control with each stage.

Page 33: Measure 13 identified that no SIPs existed or EPA guidance/requirements for the measure and incorrectly used that rationale as the conclusion for not considering the measure.

Page 34: The discussion of Measure 15 does not clearly state how Alaska and the Borough ensure that devices are taken out at the point of sale. It also does not clearly state the process for ensuring a NOASH application doesn't involve a stove that should have been taken out at the point of sale. It also states that stoves between 2.5 g/hr and 7.5 g/hr can get a NOASH, whereas page 37 implies that a stove must be <2.5 g/hr to be eligible for a NOASH.

Page 47: Measure 33 in Klamath County and Feather River is more stringent than what exists in Fairbanks now. Fairbanks allows open burning without a permit when there is no stage restriction. Alaska DEC prohibits open burning between November 1 and March 31, but the air quality plan makes it clear that the state relies on the Borough to carry out the air quality program in Fairbanks. The fact that the local borough does not require a permit for open burning outside of curtailments makes this measure less stringent in Fairbanks than in other locations. In addition, Fairbanks does not curtail warming fires during a Stage 1.

Page 48: Measure 34 is less stringent in Fairbanks than in Klamath County. Uncertainty in weather forecasting means that Stage 1 alerts are not called correctly all the time, and not

everyone is aware of when an alert is in effect. It is much simpler and less prone to error to prohibit burn barrels and outdoor burning devices entirely.

Page 57: Measure 46 review curtailment exemptions. The current Fairbanks curtailment exemption "These restrictions shall not apply during a power failure." should be reviewed to clarified that it only applies to homes reliant on electricity for heating. As currently written, it appears overly broad.

Page 68: Measure R7, Ban Use of Hydronic Heaters, incorrectly identifies that no other SIPs implemented the measure as rational for not evaluating.

Page 72: Measure R15 is technologically feasible.

Page 78: It may help to make a section break or Section 2 label for "Analysis of Marginal / Unquantifiable Benefit BACM Measures

Page 81-83: The discussion of Measure 6 may need additional documentation. Anecdotal evidence is that damping is common in Fairbanks and is potentially a bigger source of pollution than not having a damper at very cold conditions. If installation by a certified technician addresses this issue, that should be documented.

Page 84: The quote, "did not know if the rule had worked well" needs a reference. It is also not clear of how relevant that is. It could be implemented well in Fairbanks and the fact that it may not have worked well in another location does not make it technologically infeasible for this location.

Page 85-86: While qualitative assessments are helpful to provide context, a quantitative assessment will be necessary to evaluate the measures as BACM and MSM.

Page 88: There are references to Fairbanks in the conclusion for Measure 17, but the analysis refers to AAC code.

Page 89: There appears to be missing text in the Background section related to Method 9.

Page 91: Measure 23 could consider the solution that the decals could be reflective and would be seen by vehicle headlights. Measure 23 could also consider that the decals are used by neighbors to determine who is or is not in compliance. This may be helpful as citizen compliance assistance efforts could supplement the Borough enforcement program.

Page 98-100: Measure 40 needs to include a discussion of all the areas listed on page 22. In addition, if a date certain measure or if Measure 29 were instituted, Measure 40 would essentially be achieved.

Page 114: Measure R5 describes a similar rule in Utah but lists "none" under implementing jurisdictions. Please make consistent.

ULS Heating Oil

Page vii and Page 16: Please check your information on the percentage of households who have a central oil fired furnace. Please consult ADEC's contractor for the emissions inventory and home heating surveys about (1) the percentage of homes that heat only with an oil furnace, and (2) home with a central oil burner and a wood stove. We have seen different numbers than presented here.

Page 13: Please check the labels for Fairbanks HS #2 and Fairbanks HS #1. They may be switched.

Page 14: The statement that there is "a clear explanation" may not be correct, or at minimum is an overstatement. The difference in price between HS#1 and ULSD has varied over time, and the report did not include an explanation for the variations.

Page 14: The third paragraph assumes that the capital costs of shipping ULS would be more than exists today. However, all heating oil is shipped, regardless of sulfur content, and there is no justification for the report for why shipping ULS would be higher than for HS. Additionally, it is possible that the shipping cost per unit could go down marginally if only one product is being supplied to Fairbanks and/or if the quantity supplied increases.

Page 21: The text and Table 7 present inconsistent information. For instance, the text says that the discounted net-present value of scenario 2 is $10,232 while the table says it is $5,768.56.

November 28, 2018

Certified Mail
Return Receipt Requested
7017 1450 0002 1773 7925

Denise Koch, Director
Division of Air Quality
Department of Environmental Conservation
410 Willoughby Avenue, Suite 303
PO Box 111800
Juneau, AK 99811-1800

RE: Best Available Control Technology (BACT) Proposal from Golden Valley Electric Association (GVEA) for the North Pole Power Plant and Zehnder Facility.

Dear Ms. Koch,

At the request of the Alaska Department of Environmental Conservation (ADEC), Golden Valley Electric Association (GVEA) has considered alternative Best Available Control Technology (BACT) proposals and in this communication is providing updated and supplemental information. GVEA hopes this additional information is beneficial to ADEC as the Serious $PM_{2.5}$ State Implementation Plan (SIP) is finalized.

Introduction

Due to geography, our northern latitude, climatology, and types of emissions within the Fairbanks North Star Borough (FNSB), concentrations of $PM_{2.5}$ often exceed the maximum levels set by the Clean Air Act; resulting in the area being designated as being in non-attainment of the National Ambient Air Quality Standards (NAAQS) for the 24-hour $PM_{2.5}$ standard in 2009. As original attainment goals were not met, the area was reclassified as a Serious non-attainment area (NAA) and ADEC is working to finalize and submit to EPA an approvable Serious SIP that will outline methodologies for reaching attainment.

GVEA operates two stationary sources within the NAA, the North Pole Power Plant and the Zehnder Facility. With the Serious designation, ADEC requested stationary sources conduct a voluntary BACT analyses for emissions of $PM_{2.5}$ or its precursors (SO_2, NO_x, VOCs and NH_3) that have the potential to be emitted at 70 or more tons per year. GVEA prepared and submitted BACT analyses for both the North Pole and Zehnder plants that analyzed NOx and

SO_2 BACT. All NO_X and SO_2 control options evaluated were deemed infeasible by GVEA. Subsequently, ADEC proposed modifications to GVEA's calculations and presented these in draft BACT documents early in 2018. For NO_x BACT, ADEC's determination included Selective Catalytic Reduction (SCR) and water injection for the two simple cycle gas turbines at both North Pole and Zehnder, and SCR for the combined cycle turbine at North Pole. For SO_2 BACT, ADEC's determination included ULSD for the two simple cycle gas turbines at both North Pole and Zehnder.

In the March 2018 draft documents, ADEC included a draft NO_x precursor demonstration which will show that NOx emissions are not a significant contributor to secondary $PM_{2.5}$ concentrations. ADEC has communicated a high degree of confidence the NO_x precursor demonstration will be accepted and the implementation of NOx controls will not be required. As such GVEA is not addressing any new BACT considerations related to NO_x controls and is focusing on alternative proposals for SO_2 BACT at both plants[1].

Alternative BACT Request

ADEC has been sympathetic to concerns raised by the stationary sources that potential community burden in capital investment for SO_2 controls is unusually high compared to the potential benefit to $PM_{2.5}$ concentrations at ground level; concentrations which are highly influenced by home heating and especially wood burning. ADEC has asked GVEA to consider alternative BACT proposals including the option of paying into an offset fund with the caution that creative and alternative proposals would have to be measurable and enforceable. Though an offset fund could be an options, there are two reasons GVEA does not see contributions to an offset fund as a viable option. First, GVEA does not see a way at this time to equitably incorporate offset fund payments into our member rates. Second, with no assurances that further investments into BACT controls would not be necessary if attainment goals are not met, the potential for investment into both an offset fund and BACT is a deterrent.

GVEA has identified modifications in combustion fuel and operating hours as options available to reduce SO_2 emissions at GVEA's two affected facilities and presents three proposed alternatives in order of descending preference below.

Alternative SO_2 BACT Option 1
Existing Fuels and Good Combustion Practices for North Pole and Zehnder

Current Fuel Supplies

GVEA currently receives all fuel from Petro Star Inc. (PSI) with the majority coming from the local North Pole Refinery adjacent to the North Pole Power Plant. In 2017 the combined cycle turbine at North Pole (EU ID 5) began receiving a Light Straight Run (LSR) naphtha product directly from the Petro Star North Pole Refinery (PSI) via pipeline. The sulfur content of this fuel

[1] At this time, GVEA has no comment on ADEC's modifications to the NOx control calculations.

was specified to be below 30 ppm and extensive testing conducted in 2018 showed a maximum sulfur content of 27 ppm. Less than two percent of the fuel received is composed of other naphtha fuels that have sulfur contents less than 50 ppm. Assuming a maximum fuel sulfur content of 50 ppm would conservatively change the potential SO_2 emissions from this unit and the proposed second LM6000 (EU ID 6) from 6 to 10.1 tons per year (TPY). Tables 1-2 and 1-5 in GVEA's North Pole BACT analysis would be affected by this change and are included in Attachment 1.

High sulfur diesel (HSD) is trucked from the pipe rack at PSI's North Pole facility across the street to a 50,000 gallon holding tank that supplies the two GE Frame 7 gas turbines at the North Pole Plant (EU IDs 1 and 2). Similarly, HSD is trucked from PSI North Pole to the Zehnder Plant GE Frame 5's (EU IDs 1 and 2). The large majority of the fuel is No. 2 HSD that is blended with No. 1 in the winter to lower the pour point. No. 1 HSD is received on rare occasions. ULSD is trucked from PSI's Valdez refinery for use as a starting fuel and is used in smaller quantities. During times when the North Pole refinery is down for planned maintenance outages, additional ULSD is trucked to Fairbanks for production fuel.

BACT Capital Cost Assumptions

GVEA's original BACT and ADEC's proposed BACT evaluated switching to ULSD to reduce SO_2 emissions. These analyses included capital costs for bulk fuel storage to maintain reliability and security of fuel supply; these costs were apportioned between the North Pole and Zehnder plants.

If GVEA were to use ULSD for both starting and production fuel in the Frame 7's and Frame 5's, as considered for SO_2 BACT, the addition of bulk fuel storage would be required to guarantee availability of fuel for the generation units since there is no locally refined source of ULSD[2]. Fuel can be imported from the Valdez area using trucks, or from the Anchorage area using trucks or rail. Both transportation corridors are subject to disruptions from avalanches, flooding, snow storms, forest fires, or earthquakes that could delay fuel delivers. For example, a video clip available online[3] shows a massive avalanche caused ice dam that closed the single road connecting Valdez in January 2014, an avalanche accompanying record snow fall closed the road to Valdez in December 6, 2017, the 2002 Denali Fault earthquake (7.9 on the Richter scale) damaged more than 20 miles of the roadbed between Fairbanks and Valdez[4], and flooding in 2006 closed the Parks Highway near Anchorage for several days[5].

During the short annual PSI maintenance outages (occurring during summer months) GVEA has experienced near outages of fuel when it is delivered solely through long haul trucking,

[2] GVEA uses "neat" fuel for generation that does not contain the additives that are added to most fuel currently stored locally.
[3] https://www.youtube.com/watch?v=X3XzRHLYE0Y video footage of avalanche ice dam isolating Valdez.
[4] https://www.fhwa.dot.gov/publications/publicroads/03nov/05.cfm Denali Fault earthquake.
[5] https://www.matsugov.us/news/4-a-m-flood-and-road-updates Parks highway closure for flooding.

largely because the long haul (700 miles round trip versus .5 miles) complicates the timing of truck offloading. This experience with supply issues, and the potential for transportation disruption, raises concerns with the reliability of year round long hauled fuel supplies on a "just in time" basis from either Valdez or Anchorage, and particularly during the coldest winter months. In 2017, GVEA hired PDC Engineering of Fairbanks to assist in developing a concept design and cost estimate for a bulk fuel tank farm and terminal facility adjacent to the North Pole Power Plant. The technical memo presenting the conceptual study is included as Attachment 2.

As part of the BACT analyses, GVEA sought input from Delma Bratvold, an Energy Analyst with Leidos Engineering, to help extrapolate the PDC concept design. Ms. Bratvold has a long history of assisting GVEA with strategic fuel evaluations and her BACT specific summary is included as Attachment 3, presenting the estimated costs of strategic bulk fuel storage for both the North Pole Plant and Zehnder Facilities based on both potential to emit (PTE) run hours and historic run hours.

Fuel Cost Assumptions

In preparing the original BACT analyses, GVEA used actual fuel costs incurred from August 2015 through April 2016 to obtain a cost differential of $0.2668 per gallon between ULSD and No. 2 HSD. Attachment 4 shows updated pricing data for fuel received between January 2017 and October 2018 and shows an updated weighted average cost differential of $0.424 per gallon between No. 2 HSD and ULSD[6].

Cost Effectiveness

Appling the updated incremental fuel pricing increases the cost effectiveness of SO_2 removal for all primary generating units. Table 1 summarizes the cost effectiveness of switching to ULSD for the primary generating units and compares the iterations in calculations, from GVEA's original, the ADEC's to GVEA's updated. The updated cost effectiveness tables from the BACT analyses are included in Attachment 5[7].

[6] A digital version of Attachment 4 is included on the enclosed DVD.

[7] Tables referenced in this correspondence refer to similarly numbered tables in GVEA's original BACT analyses. ADEC returned to GVEA proposed modifications to the BACT tables as Excel files following ADEC's preliminary review. GVEA's most current updates are applied to ADEC's version. Updates described here are attached in hard copy and included on the accompanying DVD.

Table 1. Cost Effectiveness, $/Ton of SO_2 removal[1]			
	GVEA's 2017 BACT Cost Effectiveness ($/Ton) [2]	ADEC's Cost Effectiveness ($/Ton) [3]	GVEA's 2018 Alternative BACT Cost Effectiveness ($/Ton) [4]
North Pole			
EU ID 1	$10,025	$9,139	$13,942
EU ID 2	$10,204	$9,233	$14,037
EU ID 5/6	$9,282,151	$9,282,151	$4,844,020 [5]
Zehnder			
EU ID 1/2	$9,701	$9,050 [6]	$14,250

[1] Capital costs of $30,425,000 to install fuel storage are apportioned between North Pole and Zehnder and the cost effectiveness calculations for both plants are based on the Potential to Emit. The cost effectiveness based on actual emissions and on the conversion of SO2 to PM2.5 is significantly higher.
[2] Tables 5-4, 5-5, and 5-6 in GVEA's original BACT for North Pole and Table 5-4 in the original BACT for Zehnder.
[3] Tables 5-4, 5-5, and 5-6 in ADEC's modified BACT tables for North Pole and Table 5-4 for ADEC's modified Zehnder BACT calculations
[4] Updated Tables 5-4, 5-5, and 5-6 are included in Attachment 5. The Excel file is included on the enclosed DVD.
[5] As shown on included tables and discussed above, increasing the naphtha fuel from 30 ppm to 50 ppm sulfur content increases the potential annual SO_2 emissions from 6 to 10.1 tons and decreases the cost effectiveness.
[6] ADEC's proposed cost effectiveness for Zehnder was based on avoiding 597 tons SO_2 per year. Condition 9 of Permit No. AQ0109TVP03 already places an Owner Requested Limit (ORL) on SO_2 Emissions of 580 tons per rolling 12-month period for the Zehnder Facility. Considering the ORL, the cost effectiveness is $9,340 per ton removed.

With a cost effectiveness above $13,000 per ton of SO_2 removed, GVEA contends that switching to ULSD is not economically feasible and BACT would be the existing fuels and good combustion practices for all units at North Pole and Zehnder.

ADEC has suggested No. 1 HSD with a sulfur content of 900 ppm be considered as an alternative to No. 2 HSD. Currently, No. 1 HSD produced locally by PSI is not available in large enough quantities to be used as a production fuel. PSI is undertaking engineering studies to identify ways to expand their local production of No. 1 HSD, however they have indicated there will be competing demands; the military use is forecast to increase by 50%, and there is the projected conversion of home heating to No. 1 HSD. Production fuel for GVEA would be a non-dedicated supply and last on the priority list behind the military and home heating demands. PSI has indicated they would likely import fuel from Valdez to meet GVEA's full demands. To have a guaranteed fuel supply, this would place GVEA in a situation similar to importing ULSD with similar pricing and reliability constraints. To fully switch to No. 1 HSD would have a cost effectiveness similar to ULSD.

Alternative SO_2 BACT Option 2
North Pole - No. 1 HSD (EU IDs 1&2) on Air Quality Stage 1 and 2 Curtailment Days
Zehnder - Existing Fuels and Good Combustion Practices

North Pole Power Plant Option 2

GVEA wishes to be a constructive contributor to improving regional $PM_{2.5}$ concentrations with practical solutions that do not unfairly burden our cooperative members with negligible benefit.

As such, GVEA proposes as SO_2 BACT for North Pole EU ID's 1 and 2, the continued use of No. 2 HSD during normal operating days, with a switch to receiving No. 1 HSD (when available) when the units operate on air quality curtailment days (during Stage 1 and Stage 2 air quality alerts for the North Pole area). It will take an estimated 5 to10 operating hours to fully transition fuel. With the recent addition of Healy Unit 2 to the generation fleet, which economically produces electricity outside the NAA, GVEA anticipates the actual operation of EU ID's 1 and 2 to be reduced. New Tables 5-4a and 5-5a in Attachment 6 evaluate the cost effectiveness of targeted operation on No. 1 HSD, assuming 10% of the time, at $1,904 per ton of SO_2 avoided.

GVEA proposes as SO_2 BACT for EU ID's 5 and 6, the continued use of the current or equivalent fuels with a sulfur content of 50 ppm or less.

Zehnder Facility Option 2

GVEA proposes as SO_2 BACT the existing fuels and good combustion practices for all units at Zehnder. Condition 9 of Permit No. AQ0109TVP03 already places an Owner Requested Limit (ORL) on SO_2 Emissions of 580 tons per rolling 12-month period for the Zehnder Facility[8]. EU ID's 1 and 2 are the least economical units to run and are run only when absolutely necessary. Attachment 7 shows the 2017 actual operating hours and emissions for the Zehnder Facility as presented in the March 2018 assessable emissions estimates. These emissions are representative of operations from 2012 through 2018 (year to date) where the total SO_2 emissions have been slightly over 30 tons per year. As mentioned above, with the addition of Healy Unit 2 the Zehnder Units are modeled to run even fewer hours.

[8] If the ORL was reduced to 350 tons per year, the cost effectiveness of ULSD as evaluated in Table 1 goes to $21,989 per ton of SO_2 reduced.

Alternative SO_2 BACT Option 3
North Pole - No. 1 HSD (EU IDs 1&2) on Air Quality Stage 1 and 2 Curtailment Days
Zehnder - ORL to Remove Zehnder as a Major Source of SO_2

North Pole Power Plant Option 3 (same as Option 2)
Similar to Option 2, GVEA proposes to supply No. 1 HSD to EU ID's 1 and 2 when they are operating during air quality Stage 1 and Stage 2 alerts in the North Pole area. SO_2 BACT for EU ID's 5 and 6, would again be the continued use of the current or equivalent fuels with a sulfur content of 50 ppm or less.

Zehnder Facility Option 3
GVEA recognizes the traditional BACT process evaluates the potential to emit pollutants of concern, and the Zehnder Facility has the potential to emit many more tons of SO_2 than it historically has. The Zehnder units are the least economical to run and are run only when necessary, however, they are a critical piece to the overall system reliability and their operation is necessary in cases when other generating units are down, or the transmission Intertie with the Anchorage area is down.

As a third option, GVEA proposes to take an additional ORL on SO_2 emissions to limit them to less than 70 tons per year, thus removing the Zehnder Facility as a major source of SO_2. GVEA proposes to submit the request for permit modification by June 1, 2019 and would structure the modification to allow for operation in emergency situations. The health and welfare of GVEA's members are of upmost importance and in consideration of the extreme temperatures and winter conditions that can be experienced in the FNSB, GVEA must be able to supply electrical power to members when other sources are unavailable. Attachment 8 shows a guide used internally to prioritize outage response. For a range of outside temperatures it tabulates the time to a complete house freeze up after the loss of a heat source. With an external temperature of -30 F, a house starting with an internal temperature of 70 F can be expected to freeze after seven hours.

Other Measures

Though not measurable, enforceable, or appropriate for inclusion in the SIP, GVEA is exploring other alternatives that will help minimize emissions from power generation within the non-attainment area.

With the successful restart of Healy Unit 2, the consumption of No. 2 HSD in the North Pole and Zehnder Units has dropped from 12.4 million gallons in 2017, to an estimated 9 million gallons in 2018, to a projected 5.5 million gallons in 2019. In 2019, total SO_2 emissions in the NAA from GVEA's plants is expected to drop 192 tons over 2017. GVEA has modeled the effect of retiring Healy Unit 1 and power would be made up with both purchases from the Anchorage area and generation within the NAA. With the removal of Healy Unit 1, modeling shows an increase in NAA SO_2 emissions from the North Pole and Zehnder Plants of 28%. Options for continuing the

operation of Healy Unit 1 are being evaluated.

GVEA is also exploring options that may assist the Interior Gas Utility (IGU) in providing economical natural gas to the Fairbanks area. If feasible, GVEA may be able to convert North Pole EU ID 5 to also burn natural gas, which could help stabilize demand, or help reach some economies of scale for gas supply.

All the sources within FNSB NAA are integrally related and requirements for one source may have unintended consequences for another. As GVEA is the sole purchaser of Aurora Energy's electrical production, any BACT capital investment Aurora makes can potentially affect GVEA's member rates. Knowing that the exact accounting and correlation between the major source SO_2 stack emissions, the at-the-monitor measurements, and the modeling are inconsistent, GVEA encourages ADEC to pursue a Major Source SO_2 precursor demonstration and to work further to explain the sulfate contribution inconsistencies.

Summary

In conclusion, GVEA would like to make meaningful contributions to reducing SO_2 emissions without disproportionally burdening our member owners or sacrificing electrical system reliability. Three BACT options have been presented, in all cases for North Pole's existing EU ID 5 and proposed EU ID 6 (the combined cycle plants at North Pole) GVEA proposes to burn the existing or equivalent fuel with a sulfur content of 50 ppm or less.

As a first option, using updated fuel pricing and the actual differential costs between No. 2 HSD and ULSD, GVEA is submitting updated cost effectiveness calculations for SO_2 reductions at both the North Pole and Zehnder plants that show costs over $13,000 per ton of SO_2 reduced. GVEA proposes as SO_2 BACT the continued use of current fuels and good combustion practices for all units at North Pole and Zehnder.

As a second option, to make reductions in SO_2 emissions during times when they are needed, For EU ID's 1 and 2, the older simple cycle plants at North Pole, GVEA proposes to continue burning No. 2 HSD during normal operations, but to take delivery of No. 1 HSD[9] while operating during air quality curtailment periods.

As a final option, in addition to receiving No. 1 HSD during curtailment periods at North Pole, GVEA proposes to take an additional ORL at the Zehnder Facility to reduce annual SO_2 emissions to less than 70 tons, except in emergency situations.

[9] Subject to availability as GVEA would be third in line of preference behind Military demands and proposed home heating demands.

Sincerely,



Naomi Morton Knight, P.E.
Environmental Health & Safety Officer

Attachments/Enclosures:

- Attachment 1 - North Pole BACT Section 1 Tables
- Attachment 2 - Technical Memo from PDC Regarding Bulk Fuel Storage
- Attachment 3 - Leidos Strategic Fuel Evaluation
- Attachment 4 - January 2017 through October 2018 Fuel Prices
- Attachment 5 - Updated Cost Effectiveness Tables North Pole and Zehnder
- Attachment 6 - Tables 5-4a and 5-5a, North Pole EU ID 1 and 2 Cost Effectiveness with Selective use of No. 1 HSD
- Attachment 7 - Zehnder FY2019 Assessable Emissions Summary
- Attachment 8 - House Freeze Up Time Estimates.
- DVD

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Attachment 1
North Pole BACT Section 1 Tables

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Table 1-2. Significant Emission Unit Potential Emission Inventory

Emission Unit			Fuel	Rating	Maximum	Allowable Annual	Construction	Life	Potential Emissions (tpy)			
ID	Description	Make/Model	Type		Capacity	Operation	Date	Span	NO_X [1]	$PM_{2.5}$	SO_2 [2,3]	VOC
1	Simple Cycle Gas Turbine	GE Frame 7, Series 7001, Model BR	Fuel Oil	60.5 MW	672 MMBtu/hr	8,760 hr/yr	1976	10 years	1,600.0	35.3	1,486.4	1.2
2	Simple Cycle Gas Turbine	GE Frame 7, Series 7001, Model BR	Fuel Oil	60.5 MW	672 MMBtu/hr	7,992 hr/yr[4]	1977	10 years	2,363.1	32.2	1,356.1	1.1
3	Fuel Storage Tank	N/A	HAGO/LAGO/ Fuel Oil[5]	50,000 Gallons	50,000 Gallons	8,760 hr/yr	1995	10 years	0	0	0	0.04
4	Fuel Storage Tank	N/A	HAGO/LAGO/ Fuel Oil[5]	50,000 Gallons	50,000 Gallons	8,760 hr/yr	1995	10 years	0	0	0	0.06
5	Combined Cycle Gas Turbine	GE LM6000PC	GVEA LSR Turbine Fuel/GVEA Naphtha[6]	43 MW	455 MMBtu/hr	8,760 hr/yr	2005	10 years	478.3	23.9	10.1	0.8
6	Combined Cycle Gas Turbine	GE LM6000PC	GVEA LSR Turbine Fuel/GVEA Naphtha[6]	43 MW	455 MMBtu/hr	8,760 hr/yr	N/A	10 years	478.3	23.9	10.1	0.8
7	Emergency Generator Engine	Generac 5231150100	Fuel Oil	400 kW	461.6 kW	52 hr/yr[7]	2005	10 years	0.5	0.04	0.01	0.0
11	Boiler	Bryan Steam RV500	Gas Fuel/Propane	5.0 MMBtu/hr	5.0 MMBtu/hr	8,760 hr/yr	2005	10 years	3.1	0.2	0.0003	0.2
12	Boiler	Bryan Steam RV500	Gas Fuel/Propane	5.0 MMBtu/hr	5.0 MMBtu/hr	8,760 hr/yr	2005	10 years	3.1	0.2	0.0003	0.2
								Total Potential Emissions	3,969.8	115.7	2,862.6	4.5

[1] Combined emissions from EU IDs 1, 5, and 6 are limited to 1,600 tpy emissions of NO_X on a 12-month rolling basis per Permit AQ0110TVP03, Condition 13. Each emission unit can operate individually up to the potential NO_X emissions shown above.

[2] EU IDs 1 and 2 can combust No. 1 and No. 2 fuel oil, which (by specification) can have a maximum sulfur content of 0.5 wt. pct. The two emission units may emit no more than 24,500 pounds of SO_2 per day, combined, per Permit AQ0110TVP03, Condition 14. The fuel oil sulfur content specification of 0.5 wt. pct. S is more restrictive. Each unit could be operated individually up to the potential SO_2 emissions shown above.

[3] EU IDs 5 and 6 are limited to a combined 12-month rolling total consumption of 1.5 million gallons of startup fuel per Permit AQ0110TVP03, Condition 16.1. Each unit could be operated individually up to that limit.

[4] EU ID 2 is limited to operating no more than 7,992 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 12.

[5] HAGO and Lago are listed for completeness, but those fuels are no longer available due to the closure of the Flint Hills Refinery in North Pole.

[6] GVEA LSR Turbine Fuel (LSR) is currently being combusted in EU ID 5. This fuel is obtained from directly from the Petro Star Inc. (PSI) refinery via pipeline. PSI is supplying this fuel under a long-term contract with GVEA.

[7] EU ID 7 is limited to operating no more than 52 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 10.

Table 1-3. Significant Emission Unit Potential NO_X Emissions

Significant Emission Units		Factor	NO_X Emission	Maximum	Maximum	Regulatory Limits	Existing Control Technology		Potential NO_X
ID	Description	Reference	Factor	Capacity	Operation		Description	Efficiency (pct.)	Emissions
1	Simple Cycle Gas Turbine	AP-42 Table 3.1-1	0.88 lb/MMBtu	672 MMBtu/hr	8,760 hr/yr	NA	Regenerative System	Unknown	1,600 tpy [1]
2	Simple Cycle Gas Turbine	AP-42 Table 3.1-1	0.88 lb/MMBtu	672 MMBtu/hr	7,992 hr/yr[2]	NA	Regenerative System	Unknown[6]	2,363.1 tpy
3	Fuel Storage Tank	NA	NA	50,000 Gallons	8,760 hr/yr	NA	NA		0 tpy
4	Fuel Storage Tank	NA	NA	50,000 Gallons	8,760 hr/yr	NA	NA		0 tpy
5	Combined Cycle Gas Turbine	AP-42 Table 3.1-1	0.24 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	Subpart GG 146 ppmvd at 15 pct. O_2	Water Injection	73 [3]	478.3 tpy [1]
6	Combined Cycle Gas Turbine	AP-42 Table 3.1-1	0.24 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	Subpart KKKK 74 ppm at 15 pct. O_2 or 3.6 lb/MWh	Water Injection	73 [3]	478.3 tpy [1]
7	Emergency Generator Engine	AP-42 Table 3.3-1	0.031 lb/hp-hr	461.6 kW	52 hr/yr[5]	NA	Turbocharger and Aftercooler + Limited Operation	99	0.5 tpy
11	Boiler	AP-42 Table 1.5-1	13 lb/10^3gal	5.0 MMBtu/hr	8,760 hr/yr	NA	NA		3.1 tpy
12	Boiler	AP-42 Table 1.5-1	13 lb/10^3gal	5.0 MMBtu/hr	8,760 hr/yr	NA	NA		3.1 tpy
							Total Potential Emissions		3,969.8 tpy[4]

Sample Calculations:

Turbine Emissions, tpy= (Emission factor, lb/MMBtu) * (Capacity, MMBtu/hr) * (Operation, hr/yr) / (2,000 lb/ton)

Engine Emissions, tpy= (Emission factor, lb/hp-hr) * (Capacity, kW) * (Conversion, 1.341 hp/kW) * (Operation, hr/yr) / (2,000 lb/ton)

Heater (Boiler) Emissions, tpy= (Emission factor, lb/10^3gal) * (Conversion, 10^3gal/91.5 MMBtu) * (Capacity, MMBtu/hr) * (Operation, hr/yr) / (2,000 lb/ton)

- Propane heat content is assumed to equal 91.5 MMBtu/10^3 gallon per AP-42 Table 1.5-1.

Notes:

[1] Combined emissions from EU IDs 1, 5, and 6 are limited to 1,600 tpy NO_X emissions on a 12-month rolling basis per Permit AQ0110TVP03, Condition 13. Each unit can operate individually up to the potential emissions shown above.

[2] EU ID 2 is limited to operating no more than 7,992 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 12.

[3] AP-42, Table 3.1-1 infers a control efficiency of 73 pct. for water injection. While 77 pct. was listed in recent Emission Unit Inventory submittals, 73 pct. is used in this analysis. Permit AQ0110TVP03, Condition 13.2 requires water injection for EU IDs 5 and 6.

[4] Total potential emissions have been adjusted to reflect ORL restrictions.

[5] EU ID 7 is limited to operating no more than 52 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 10.

[6] The EU ID 2 regenerative system was rebuilt during 2012-2013 and is expected to be more effective than the regenerative system on EU ID 1 but has not been quantified.

Table 1-4. Significant Emission Unit Potential $PM_{2.5}$ Emissions

Significant Emission Units		Factor	PM Emission	Maximum	Maximum	Regulatory Limits	Existing Control Technology		Potential $PM_{2.5}$
ID	Description	Reference	Factor	Capacity	Operation		Description	Efficiency (pct.)	Emissions
1	Simple Cycle Gas Turbine	AP-42 Table 3.1-2a	0.012 lb/MMBtu	672 MMBtu/hr	8,760 hr/yr	NA	NA		35.3 tpy
2	Simple Cycle Gas Turbine	AP-42 Table 3.1-2a	0.012 lb/MMBtu	672 MMBtu/hr	7,992 hr/yr[1]	NA	Limited Operation	9	32.2 tpy
3	Fuel Storage Tank	NA	NA	50,000 Gallons	8,760 hr/yr	NA	NA		0 tpy
4	Fuel Storage Tank	NA	NA	50,000 Gallons	8,760 hr/yr	NA	NA		0 tpy
5	Combined Cycle Gas Turbine	AP-42 Table 3.1-2a	0.012 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	NA	NA		23.9 tpy
6	Combined Cycle Gas Turbine	AP-42 Table 3.1-2a	0.012 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	NA	NA		23.9 tpy
7	Emergency Generator Engine	AP-42 Table 3.3-1	0.0022 lb/hp-hr	461.6 kW	52 hr/yr[2]	NA	Limited Operation + Positive Crankcase Ventilation	99	0.035 tpy
11	Boiler	AP-42 Table 1.5-1	0.7 $lb/10^3$gal	5.0 MMBtu/hr	8,760 hr/yr	NA	NA		0.2 tpy
12	Boiler	AP-42 Table 1.5-1	0.7 $lb/10^3$gal	5.0 MMBtu/hr	8,760 hr/yr	NA	NA		0.2 tpy
							Total Potential Emissions		115.7 tpy

Sample Calculations:

Turbine Emissions, tpy= (Emission factor, lb/MMBtu) * (Capacity, MMBtu/hr) * (Operation, hr/yr) / (2,000 lb/ton)

Engine Emissions, tpy= (Emission factor, lb/hp-hr) x (Capacity, kW) * (Conversion, 1.341 hp/kW) * (Operation, hr/yr) / (2,000 lb/ton)

Heater (Boiler) Emissions, tpy= (Emission factor, $lb/10^3$gal) * (Conversion, 10^3gal/91.5 MMBtu) * (Capacity, MMBtu/hr) * (Operation, hr/yr) / (2,000 lb/ton)

- Propane heat content is assumed to equal 91.5 MMBtu/10^3 gallon per AP-42 Table 1.5-1.

Notes:

[1] EU ID 2 is limited to operating no more than 7,992 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 12.

[2] EU ID 7 is limited to operating no more than 52 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 10.

Table 1-5. Significant Emission Unit Potential SO_2 Emissions

Significant Emission Units		Factor	Maximum Fuel	SO_2 Emission	Maximum	Maximum	Regulatory Limits	Existing Control Technology		Potential SO_2
ID	Description	Reference	Sulfur Content	Factor	Capacity	Operation		Description	Efficiency (pct.)	Emissions
1	Simple Cycle Gas Turbine	AP-42 Table 3.1-2a	0.50 wt. pct. S[1]	0.51 lb/MMBtu	672 MMBtu/hr	8,760 hr/yr	Permit AQ0110TVP03 Combined emission limit of 24,500 lb/day[1]	NA		1,486.4 tpy[1]
2	Simple Cycle Gas Turbine	AP-42 Table 3.1-2a	0.50 wt. pct. S[1]	0.51 lb/MMBtu	672 MMBtu/hr	7,992 hr/yr[2]		Limited Operation	9	1,356.1 tpy[1]
3	Fuel Storage Tank	NA	NA	NA	50,000 Gallons	8,760 hr/yr	NA	NA		0 tpy
4	Fuel Storage Tank	NA	NA	NA	50,000 Gallons	8,760 hr/yr	NA	NA		0 tpy
5	Combined Cycle Gas Turbine	AP-42 Table 3.1-2a (non-startup)	0.005 wt. pct. S[3]	0.005 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	Subpart GG 150 ppmvd at 1 5 pct. O_2 or 0.8 wt. pct. S	Low Sulfur Fuel (0.05 pct by weight)	N/A	10.1 tpy
		Mass Balance (startup)	0.3 wt. pct. S[4]	0.037 lb/gal		1,500,000 gal/yr		NA		N/A[4]
		Total								10.1 tpy
6	Combined Cycle Gas Turbine	AP-42 Table 3.1-2a (non-startup)	0.005 wt. pct. S[3]	0.005 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	Subpart KKKK 0.9 lb/MWh emissions	Low Sulfur Fuel (0.05 pct by weight)	N/A	10.1 tpy
		Mass Balance (startup)	0.3 wt. pct. S[4]	0.037 lb/gal		1,500,000 gal/yr	Subpart KKKK 0.06 lbSO_2/MMBtu fuel	NA		N/A[4]
		Total								10.1 tpy
7	Emergency Generator Engine	Mass Balance	0.1 wt. pct. S[5]	0.014 lb/gal	32 gal/hr[6]	52 hr/yr[7]	NA	Limited Operation	99	0.01 tpy
11	Boiler	AP-42 Table 1.5-1	0.012 wt. pct. S[8]	0.0012 lb/10^3gal	5.0 MMBtu/hr	8,760 hr/yr	NA	Low Sulfur Fuel (propane - 120 ppmv)	Unknown	0.0003 tpy
12	Boiler	AP-42 Table 1.5-1	0.012 wt. pct. S[8]	0.0012 lb/10^3gal	5.0 MMBtu/hr	8,760 hr/yr	NA	Low Sulfur Fuel (propane - 120 ppmv)	Unknown	0.0003 tpy
									Total Potential Emissions	2,862.6 tpy[9]

Sample Calculations:

Molar mass ratio is 32 lb S/mol : 64 lb SO_2/mol

Stoichiometry: 1 mol S = 1 mol SO_2

Mass Balance Emission Factor, lb/gal = (Molar mass ratio, 2 lb SO_2:1 lb S) * (wt. pct. S in fuel) * (density of fuel, lb/gal) / 100%

Turbine Emissions (Normal Operation), tpy= (Emission factor, lb/MMBtu) * (Capacity, MMBtu/hr) x (Operation, hr/yr) / (2,000 lb/ton)

Turbine Emissions (Startup), tpy= (Emission factor, lb/gal) * (Throughput, gal/yr) / (2,000 lb/ton)

Engine Emissions, tpy= (Emission factor, lb/gal) * (Capacity, gal/hr) * (Operation, hr/yr) / (2,000 lb/ton)

Heater (Boiler) Emissions, tpy= (Emission factor, lb/10^3gal) * (Conversion, 10^3gal / 91.5 MMBtu) * (Capacity, MMBtu/hr) * (Operation, hr/yr) / (2,000 lb/ton)

wt. pct. S (in diesel) = (Sulfur compound emission limit, ppmv SO_2) * (Conversion, 1.66E-7 lb SO_2/scf / ppm SO_2) x (F-factor, 9,190 scf/MMBtu) * (Conversion, 0.0193 MMBtu/lb) * (Conversion, mole SO_2/64 lb SO_2) x (Conversion, mole S/mole SO_2) * (Conversion, 32 lb S/ mole S)

-Turbine startup fuel is assumed to have an average density of 6.2 lb/gal. Emergency generator fuel is assumed to equal 7.1 lb/gal per note (a) of AP-42 Table 3.4-1.

- Propane heat content is assumed to equal 91.5 MMBtu/10^3 gallon per AP-42 Table 1.5-1.

Notes:

[1] EU IDs 1 and 2 can combust No. 1 and No. 2 fuel oil, which (by specification) can have a maximum sulfur content of 0.5 wt. pct. The two emission units may emit no more than 24,500 pounds of SO_2 per day, combined, per Permit AQ0110TVP03, Condition 14. The fuel oil sulfur content specification of 0.5 wt. pct. S is more restrictive. Each unit could be operated individually up to the potential SO_2 emissions shown above.

[2] EU ID 2 is limited to operating no more than 7,992 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 12.

[3] The normal operating fuel for EU IDs 5 and 6 is LSR Naphtha obtained from PSI under a long-term contract. The sulfur content of the LSR is limited to no more than 30 ppmw by the terms of that contract, a small percentage (<2%) of fuel may be made up with other naphtha blends with sulfur content no more than 50 ppmw. A conservative fuel sulfur content of 50 ppm is used for calculating SO_2 emissions from EU IDs 5 and 6.

[4] EU ID 5 is a "base-load" unit that is operated continuously for extended periods of time. EU ID 6, if constructed, will be operated in the same manner. As a result, startups on No. 1 or No. 2 fuel oil are infrequent, so potential emissions from startups are not included.

[5] EU ID 7 is limited to a fuel sulfur content of 0.1 wt. pct per Permit AQ0110TVP03, Condition 9.

[6] The engine specification datasheet indicates a maximum fuel throughput of 32 gal/hr.

[7] EU ID 7 is limited to operating no more than 52 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 10.

[8] EU IDs 11 and 12 are limited to a fuel sulfur content of 0.012 wt. pct. per Permit AQ0110TVP03, Condition 11.

[9] Total potential emissions have been adjusted to reflect annual operating hour restrictions.

Table 1-6. Significant Emission Unit Potential VOC Emissions

Significant Emission Units		Factor	VOC Emission	Maximum	Maximum	Regulatory Limits	Existing Control Technology		Potential VOC
ID	Description	Reference	Factor	Capacity	Operation		Description	Efficiency (pct.)	Emissions
1	Simple Cycle Gas Turbine	AP-42 Table 3.1-2a	0.00041 lb/MMBtu	672 MMBtu/hr	8,760 hr/yr	NA	NA		1.2 tpy
2	Simple Cycle Gas Turbine	AP-42 Table 3.1-2a	0.00041 lb/MMBtu	672 MMBtu/hr	7,992 hr/yr[1]	NA	Limited Operation	9	1.1 tpy
3	Fuel Storage Tank	TANKS 4.0.9d	-	50,000 Gallons	8,760 hr/yr	NA	NA		0.04 tpy
4	Fuel Storage Tank	TANKS 4.0.9d	-	50,000 Gallons	8,760 hr/yr	NA	NA		0.06 tpy
5	Combined Cycle Gas Turbine	AP-42 Table 3.1-2a	0.00041 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	NA	NA		0.8 tpy
6	Combined Cycle Gas Turbine	AP-42 Table 3.1-2a	0.00041 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	NA	NA		0.8 tpy
7	Emergency Generator Engine	AP-42 Table 3.3-1	0.003 lb/hp-hr	461.6 kW	52 hr/yr[2]	NA	Limited Operation	99	0.0 tpy
11	Boiler	AP-42 Table 1.5-1	0.8 lb/10^3gal	5.0 MMBtu/hr	8,760 hr/yr	NA	NA		0.2 tpy
12	Boiler	AP-42 Table 1.5-1	0.8 lb/10^3gal	5.0 MMBtu/hr	8,760 hr/yr	NA	NA		0.2 tpy
							Total Potential Emissions		4.5 tpy

Sample Calculations:

Turbine Emissions, tpy= (Emission factor, lb/MMBtu) * (Capacity, MMBtu/hr) * (Operation, hr/yr) / (2,000 lb/ton)

Engine Emissions, tpy= (Emission factor, lb/hp-hr) * (Capacity, kW) * (Conversion, 1.341 hp/kW) * (Operation, hr/yr) / (2,000 lb/ton)

Heater (Boiler) Emissions, tpy= (Emission factor, lb/10^3gal) * (Conversion, 10^3gal/91.5 MMBtu) * (Capacity, MMBtu/hr) * (Operation, hr/yr) / (2,000 lb/ton)

- Propane heat content is assumed to equal 91.5 MMBtu/10^3 gallon per AP-42 Table 1.5-1.

Notes:

[1] EU ID 2 is limited to operating no more than 7,992 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 12.

[2] EU ID 7 is limited to operating no more than 52 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 10.

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Attachment 2
Technical Memo from PDC Regarding Bulk Fuel Storage

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Transforming Challenges into Solutions

TECHNICAL MEMORANDUM

Client #	PO 201751812	**Date**	June 28, 2017
PDC #	17099FB	**Prepared by**	David Sandberg, EIT, Karen Brady, PE
Project Name	North Pole Fuel Storage Facility	**Reviewed by**	Keith Hanneman, PE
Subject	***Concept Design Alternative Site Layout***		

Topic	Discussion
Summary	The proposed Bulk Fuel Tank Farm and Terminal Facility at the GVEA site in North Pole will provide a dependable fuel source for GVEA's critical power generation operations. The purpose of this technical memorandum is to present the requirements for the facility along with alternatives (including costs) for the site arrangement and recommendation. The various functions of this facility would include storing fuel for the existing power generating systems, with the ability to load and unload fuel from tanker trucks and to unload rail cars on site. It will also provide GVEA with the ability to receive both ultra-low sulfur diesel (ULSD) and QB naphtha from Petro Star to fill the tanks. The facility arrangement will accommodate Interior Gas Utility's (IGU) future needs for liquid natural gas storage, regasification for distribution and GVEA power use. Additionally, it will provide space for a Petro Star rail loading and unloading rack with driveway access to H&H Road and Old Richardson Highway through the GVEA 138 kV right-of-way. This memo was developed based on information provided from the following: • PDC Engineers has developed the site arrangements and general coordination between the various stake holders including GVEA, Petro Star, Alaska Railroad, and Interior Gas Utility (IGU). • Great Northern Engineers (GNE) has developed the design criteria and details for the fuel tanks, containment, controls, pumping, and fuel piping. The costs associated with these items were estimated by GNE. • Shannon & Wilson has provided a soils analysis and general recommendations based on historical data and recent borings. • CHI has provided thermal exclusion zones for the future IGU storage facilities. • HMS, Inc. provided the overall estimate for the three alternatives incorporating the fuel infrastructure pricing that GNE provided, along with additive alternates. Following the review of these concepts with GVEA and consensus on the preferred alternative, the design team may be given notice to prepare construction documents.

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General Facility Requirements

The major components of this facility are summarized below. For further details see the attached Basis of Design.

Fuel Storage Tanks

The overall volume for fuel storage is being evaluated by others. Based on the initial evaluation this concept is to provide a total of 3 million gallons (MMG) storage in two tanks. GVEA will have the ability to store either ULSD or QB Naphtha with one tank having a fixed roof and the other a floating roof (as required for QB Naptha).

Based on soils information there is approximately 6 to 10 feet of silt overlying alluvial sands and gravels that would need to be removed and replaced with gravel following deep dynamic compaction beneath the proposed tank foundations.

The tanks would be constructed within a 6- to 7-foot-high containment dike that would hold 110% of the capacity of a single tank plus precipitation and freeboard. They would be surrounded by a 7-foot-tall security fence that would have gated vehicle access.

Fire Suppression

The fuel tanks would be protected from fire with a fire suppression system, as required by the Fire Marshall since each diesel tank will exceed 1,500 SF of surface area (a much smaller 364,000-gallon tank about 44 feet in diameter would have 1,500 SF surface area). This system would consist of aqueous film forming foam (AFFF) water supply lines originating from a room in the Pump Building that would route to shell mounted foam chambers on each tank.

This automated foam system, which will respond when triggered by an alarm, will be housed in the pump building. Additional firefighting infrastructure will be installed around the tank farm, truck rack and rail facility.

Truck Unloading/ Loading

The truck unloading/loading facility would allow for filling or receiving fuel from two A-train double fuel tanker trucks simultaneously at two stations at a maximum rate of 600 gpm per station. It will be a paved surface with a concrete drive-on lane provided with spill containment and drive-off protection. Surface water will be routed to an oil/water separator which would discharge clean water to surface and oily water to the City of North Pole's industrial wastewater line along H&H Road.

Railroad Unloading

A rail spur would be constructed to support the proposed rail rack. This would provide two spurs, with a combined capability of receiving up to 20 23,500-gallon tanker cars. These are the same size cars used for rail distribution at the Flint Hills Terminal Facility. The volume will vary with the site layout, from 423,000 to 470,000 gallons. The rail rack would support unloading ULSD from two rail tanks simultaneously at a maximum rate of 600 gpm. Containment would be provided for potential spills to hold the volume of one car (23,500 gallons).

In order for the rail cars to be positioned for unloading, a Trackmobile would be provided along with a 30'x45' CMU structure for housing it at the end of the spur. The trackmobile would be operated by GVEA. A small, heated, wood-framed structure would be provided for operators unloading train cars to warm up in during the winter.

The cost of the rail tracks is included in the estimates for this project and is broken into GVEA, IGU, and Petro Star Rail facilities.

Fuel Metering and Quality Assurance

Liquid metering systems will be provided for all fuels entering and leaving GVEA custody. Meters will be used to deliver a determined flow rate and comply with standard local and federal codes for fuel handling.

Instrumentation will be Ovation or at least compatible with the existing Ovation Terminal Management System. Meters will be periodically tested with a prover system to ensure they accurately record the quantity of fuels transferred.

Fuels quality can be assured through on-site laboratory analysis. The fuels quality control lab will be located in the control building and have the necessary equipment to verify all fuel cargo and inventory meet the standards required, particularly for low sulfur fuel.

Buildings

A 30'x40' pump house building would be provided to house four centrifugal pumps along with small transfer pumps associated with tank fill/suction, and supply to the fuel transfer facility. It would also contain a pair of filter trains for particulate and water removal for fuels entering and leaving the storage tanks. The building would house two oil water separators. One to treat surface water from the tank containment and unloading facilities. The other to treat water removed from the storage tanks. This building would also house the AFFF support system. The building would be approximately 1,200 sf constructed of CMU block. It would be heated to maintain a comfortable working temperature during the winter utilizing heat from the control building.

The 30'x40' control building would house controls, a single office space, storage dedicated to the maintenance and operation of this facility, and a bathroom. This will be the central point of operation of the facility but will integrate with the facility operations by means of a packaged terminal management system. This building would be similar size and construction to the pump house building.

Exterior Fuel Piping

The fuel piping would be ASTM A53 Gr. B, Sch. 40 steel pipe rated for an ANSI Class 150 system. It would be fabricated and installed in accordance with ASME B31.3 standards for welding and non-destructive examination requirements.

Piping systems shall be buried where appropriate, adequately supported when above ground, and designed to withstand the maximum stresses in accordance with ASME required load combinations such as pressure, thermal expansion, gravity loads and seismic loading.

All piping will include a three-coat exterior field coating consisting of an appropriate epoxy system with a urethane topcoat to prevent chalking and UV degradation.

Security

Physical security would be provided at the facility with a 7-foot chain link fence topped with razor wire to surround the fuel tanks, rail and truck facilities. Access would be provided to vehicles with electronic proximity readers. Building access would also utilize electronic proximity readers and Best type "TC" keying standard.

Tanks will be located to provide separation distances and vegetated buffers. CCTV surveillance would be provided through video monitoring at vehicle gates, building entrances, perimeter fence, pump control rooms, truck unloading area, and rail area. Intrusion detection would be provided using infrared sensors for motion detection in addition to magnetic switches at doors.

Alarming and monitoring will be provided from a central panel to dispatch local police to potential trespassers should an alarm get triggered.

Access Road

A new paved access road to the power plant would allow GVEA to enter the NPEP and NPG property off of H&H Road without going through Petro Star or Flint Hills. The alignment would be south of the existing traveled way to provide a corridor for the fuel piping between the road and the existing infrastructure. It will be a 30-foot wide, paved, and have gated access off of H&H road. This road would also allow access fuel storage in Alternatives 1A and 1B.

Interior Gas Utility Shared Use of Land East of H&H Road

GVEA has committed to shared use of their land east of H&H with IGU to support IGU development of LNG offloading, storage, and re-gasification to support GVEA power generation and IGU's distribution system. To make sure that the alternatives developed for the GVEA fuels were compatible with code/safety requirements, CHI Engineering performed a planning level analysis on the storage volumes required for the following scenarios as discussed during the project kick-off meeting:

1. Short Term: 3 years to support IGU growth into Phases 1-3
   a. Distribution 100 psi maximum – odorized
   b. 150,000 gallon storage (three 75,000 gallon horizontal tanks to provide (N+1))
   c. 5 day storage needed for residential
2. Long Term: After 3 years to meet long-term growth for IGU into Phase 1-3 and GVEA power generation
   a. May want to increase residential to 7 day supply or 300,000 gallons
   b. 700,000 gallons of LNG storage (7 day supply at 100,000 gallons per day) as previously discussed by GVEA as potential.
   c. 1,000,000 gallons of LNG storage for combined GVEA and residential.
3. Ultimate Plan
   a. IGU is required to provide 5 days of storage for firm customers and will work with GVEA on shared storage. As additional IGU customers are added, the storage will increase. Ultimate storage quantity is undefined at this time so it is important to have room for expansion.

Based on the above storage volumes, the offsets required for the 10,000 kBTU/hr/ square foot LNG thermal exclusion zone to property lines or facilities that are not under IGU's control are:

- Short Term 75k Gallon horizontal tanks and LNG unloading station: 184-foot radius
- 1.0 MMG Single Containment: 439' radius
- 1.0 MMG Full Containment: 134' radius

In addition to the tanks, the IGU use will include the "balance of plant," which includes:

- Two low-pressure vaporization trains for distribution
- One high-pressure vaporization train for GVEA powerplant needs
- Truck unloading stations for unloading two trucks simultaneously.
- Plant control building
- boil-off system
- control and hazard detection systems
- send-out metering
- pressure regulation and odorization
- fire protection
- plant utilities
- hazard detection systems.

The planning also included parallel rail spurs to stage railcars for LNG ISO tank offloading. The offset for the railcar unloading to property line and buildings for the 10,000 kBTU/hr/square foot LNG thermal exclusion zone was assumed to be 125 feet but needs detailed coordination with the ARRC before being finalized.

At this planning level, it appears there is sufficient space along the H&H side of the large trapezoidal parcel for the short-term horizontal storage and the balance of plant while allowing room for the future 1MMG single containment storage tank. This is the preferred configuration by IGU as it reduces their development costs.

The final determination of space requirements will require performing a Facility Plan study for the IGU operations at this site. In case the Facility Plan shows that the truck unloading facility or short-term horizontal storage will not fit, the triangle parcel north of the GVEA fuel lines should be reserved for this potential use.

City of North Pole Water Source Protection

The City of North Poles water supply wells are located approximately ¾ of a mile from the proposed fuel facility. Groundwater modeling that was performed for the ADEC Approval to Construct the wells shows that the boundary for the 2-year area of influence crosses through the proposed site. This is shown in the Site Layouts C1-C3.

There are two boundary lines shown on the drawing. The minimum area crosses through the parcel of land east of H&H Road. This assumes that the ground is free of permafrost. The maximum area boundary is located just west of H&H Road. Construction of the fuel storage facility within the area of influence will likely require mitigation to show the City that the wells are protected from potential spills. Additional coordination with ADEC, the City, soil investigation, and groundwater modeling would be needed for placement of tanks within this area. Also, additional soil testing may be required to verify if permafrost is present within the area of influence.

Alternatives

Three alternatives were developed to evaluate the best use of space. The alternatives are described below and shown in attached Site Layouts C1-C3. The cost breakdowns

are also attached. Based on the estimates, there is only a 2% difference in cost associated with the alternatives; therefore they should be considered equal at this stage. There is a 50% contingency included in the costs for budgeting.

Alternative 1 ***Fuel Storage Tanks West of H&H Road***

The Tank Farm is sited west of H&H Road and located inside a perimeter that is already fenced. Pump and control buildings are located adjacent to tank farm. The rail facility is located east of H&H. The future peaker plant may be located north of the future rail facility, and future fuels expansion would be possible adjacent to Old Richardson Hwy.

There are two variations with this alternative. In **Alternate 1A** the truck facility would be located adjacent to the fuel facility on the west side of H&H Road and would require the purchase of additional land from Flint Hills. In **Alternative 1B** the tanks would be rotated 90° to keep them within the limits of GVEA property and the truck facility would be located on the east side of H&H Road.

- Cost: $26,800,000
- Pros
  - Tanks (and truck facility in Alt 1A) would be located away from future IGU infrastructure reducing impacts associated with those unknowns
  - Maintains all future items east of H&H Road
  - Fuel storage tanks would be located outside of the 2-year area of influence for the City of North Poles water supply wells.
- Cons
  - Property must be acquired from Flint Hills Resources (FHR) for Alt 1A
  - No room for future fuels storage west of H&H
  - Cold storage tent demolition required for construction of the tanks
  - Potential demolition of existing FHR structures and obstructions requirement (foundations, abandoned piping, conduit, pavement, etc.)

Alternative 2 ***Fuel Storage Tanks East of H&H Road***

Tank Farm is sited east of H&H Road, north of rail facilities. Pump and control buildings are located in-between the tank farm and H&H. The future peaker plant may be located west of H&H, closer to the North Pole Expansion Plant , and future fuels expansion would be possible adjacent to Old Richardson Hwy.

- Cost: $26,500,000
- Pros
  - All existing and future power generation occurs west of H&H Road; would allow for future Peaker Plant to be near other turbine plants
  - No additional property acquisition from FHR required
  - One less pipe crossing H&H Road
  - Room for additional fuels storage. If the tank farm needed additional capacity in future the tanks would be grouped together and could share spill containment/drainage, fire suppression, piping, etc.
  - Cold Storage Building demolition not required for fuel storage construction

- Cons
  - Less efficient tank farm dimensions to fit site
  - Truncated north GVEA rail spur to site Tank Farm (2 less rail cars)
  - More congestion sharing space with Petro Star & IGU
  - Potentially increased soils improvement requirement
  - Mitigation will likely be required to protect City of North Poles water supply wells.

Alternative 3 ***Fuel Storage Tanks Adjacent to Old Richardson Highway***

Similar to Alternative 2, Tank Farm is sited east of H&H Road, north of rail facilities. Pump and control buildings are located in-between the tank farm and H&H. Future peaker plant may be located west of H&H, closer to the North Pole Expansion Plant, and more convenient future fuels expansion would be possible to the west of the Tank Farm.

- Cost: $27,400,000
- Pros
  - Similar to Alternative 2, as all power generation occurs west of H&H Road and Cold Storage does not require demolition for fuel storage construction,but allows easier access for future construction equipment if additional tanks were added and is more flexible if desired tank size increases.
  - Simplifies access to Petro Star Rail Facility
  - Does not bottleneck future development of GVEA land from the west
- Cons
  - Less efficient tank farm dimensions to fit site
  - Greater earthwork requirement for deeper overburden on east side of site
  - Potentially increased soils improvement requirement
  - Greater length of piping than Alternative 2
  - Mitigation will likely be required to protect the City of North Poles water supply wells.

Recommendation

Each alternative is technically viable; however Alternative 1 would keep the fuel storage tanks out of the City of North Poles 2-year Area of Influence which would simplify the permitting process.

Alternative 1A would keep all future facilities east of H&H allowing for the need, sizing, and layout to be further developed with little impact to the storage facility. The other alternatives do not have any significant operational or future expansion benefits. There is also a chance that the peaker plant may not be installed in North Pole. In the event that GVEA wants it to be closer to the other generation facilities in North Pole there is a possibility of that to be installed east to of the Old Turbine Building.

Attachments

1. Basis of Design
2. Alternative Site Layouts
3. Piping Schematics
4. Tank Flow Diagram
5. Fuel Piping List
6. Soils Report
7. CHI LNG Memo
8. Cost Estimate

Transforming Challenges into Solutions

TECHNICAL MEMORANDUM

Client #	PO 201751812	**Date**	June 28, 2017
PDC #	17099FB	**Prepared by**	David Sandberg, EIT, Karen Brady, PE
Project Name	North Pole Fuel Storage Facility	**Reviewed by**	Keith Hanneman, PE
Subject	***Basis Of Design***		

Topic	Discussion
Introduction	The purpose of this technical memorandum is to present the basis of design for the proposed North Pole Fuel Storage Facility.

Design Criteria

- API-650 Standard, *Welded Tanks for Oil Storage*
- ASME B31.3, *Process Piping*
- NFPA 59A
- 2012 IFC
- ADEC
- 2015 IBC
- AASHTO
- ADOT&PF Driveway Standards
- Alaska Railroad – *Technical Standards for Roadway, Trail, and Utility Facilities in the ARRC Right of Way*
- MUTCD 2016 Edition – *Manual on Uniform Traffic Control Devices*
- City of North Pole standards and ordinances
- 49CFR Part 193 Liquefied Natural Gas Facilities: Federal Safety Standards

Fuel Storage Tanks

Size

- Two (2) 36,000 bbl welded steel tanks, for a total storage capacity of 3 million gallons
- Constructed in accordance with the API-650 Standard, *Welded Tanks for Oil Storage*
- 85 feet in diameter and 40 feet tall.
- 36-foot nominal fill height

Configuration

- One (1) internal floating-roof tank for storing more volatile QB Naphtha which Petro Star currently supplies to GVEA. This will prevent vapor emissions from exiting the tank for product conservation and air quality and safety.
- One (1) external fixed-roof tank will store ULSD,
- The construction scope for the tanks would include fabrication, delivery, erection, non-destructive examination, internal appurtenances, hydrostatic testing, and field coating of the tank interior bottom and exterior.
- The tanks would be entirely field fabricated, although shell plates could be rolled, sandblasted and primed prior to delivery to the job site. Field striping of shell welds and final coatings would be performed after erection.
- The Contractor would erect the tanks on the already completed foundations and corrosion protection beds.

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Topic	Discussion

- Appurtenances for the tanks would consist of cargo and service nozzles, water draw-off system, auto gauge level controls, level switches for overfill prevention and pump protection, pressure/vacuum conservation venting, shell mounted AFFF supports, and double block and bleed plug valves on cargo and service tank nozzles.

Foundations

- Soil conditions and geotechnical engineer's recommendation, based on the tank loads, will govern. (See attached "Geotechnical Findings Report.")
- As is common in the Fairbanks area, proposed sites have significant liquefaction hazard, primarily loss of shear strength and settlement during seismic events, due to unconsolidated alluvial deposits at depth.
- Site preparation for all structures will require removal of surficial silty frost susceptible soils and replacement with compacted structural fills.
- Ground improvement will include the entire structure footprint and extend out beyond the outside edge of all foundations a minimum of 25 feet.
- Depth of ground improvement is between 30 to 35 feet below grade.
- Deep dynamic compaction (DDC) is recommended for ground improvement.
- Consider future site expansion/development when defining limits of ground improvement.
- Consider ground improvement during periods of low groundwater to maximize depth of improvement (spring, typically).
- Excavation for tank foundations assumes 10 feet of native soils will be removed and NFS structural backfill imported, per geotechnical report.
- Tank foundations would be nominally 5 feet deep concrete ring wall and be constructed in a typical stem ring wall/footer configuration.
- Tank foundation will have significant amounts of steel reinforcement (typical)
- Tank stem walls will be nominally 16 to 20 inches thick with footers that are approximately 6 feet wide (typical)
- Given the ratio of the height to diameter tank anchoring to the foundation is likely not required.

Setbacks

- Minimum distance to nearest property line that is or can be built upon including the opposite side of a public way: 1/2 tank diameter or 42.5 feet
- Minimum shell-to-shell tank spacing: 1/6 times sum of adjacent tank diameters or 28.5 feet
- Setback from tank and rail car loading/offloading to tanks, buildings, property lines: 25 feet
- Minimum distance from nearest side of any public way or from nearest important building on the same property: 14.17'
- Construction and maintenance clearances: Minimum 20 feet clear between the tank shell and inside toe of the adjacent dike walls is desirable.
- Homeland Security does not have criteria that apply to this facility. However, the site arrangement will be sent for review.

Topic	Discussion
	• General setbacks used for the alternatives match those used by Flint Hills on the adjacent property. ***Containment*** • The tanks would be constructed within an earthen containment dike that is capable of holding a minimum of 110% of the largest tank volume in the event of a release, with an allowance for local precipitation and freeboard. • The containment area would allow for controlled drainage via a subgrade collection system consisting of catch basins, perforated pipe within the porous backfill, and heat traced arctic pipe routed to a central Oily Water Separator (OWS) which also will handle oily water from the rail and truck loading racks before discharging into the city sewer system. • The berm is assumed to be constructed to approximately 6-7 feet above tank farm finished grade. • The berm would have a minimum 3-4 foot flat top (10 feet desirable for ease of construction and maintenance) where the containment liner membrane would be anchored. • This berm would have an outside toe to toe dimension of approximately 28 feet at a 2H:1V slope, which is suitable to maintain vegetation • The containment dike will be underlain with a geo-membrane that is impervious to the petroleum products being stored. The geo-membrane liner will be seam welded and would be installed with a layer of bedding sand and geotextile protective fabric on either side to prevent tearing or puncturing the liner during installation or compaction efforts. The liner would be continuous underneath the tank ring wall foundations. • Tank foundations would be constructed with a separate membrane underneath and within them. This would contain a tank bottom leak inside the foundation system without impacting the rest of the site. • A leak detection system within the foundation containment will allow for notification if a tank leak has occurred. • Excavation for areas not directly underneath tanks is assumed to require the removal of 4 feet of native soils. A geotextile liner will be installed with a minimum 12 inches of bedding material above and below it for protection ***Corrosion Protection*** • Sacrificial anode grid system installed in the bedding beneath each tank to protect the underside from corrosion by means of an impressed current system that requires an external power supply and a rectifier. This is the most common system utilized for tanks of this size and type • Tanks will be externally coated with a three component coating system consisting of prime, intermediate, and top coat. The first two coats are assumed to be a polyamide epoxy and the top coat, polyurethane to prevent chalking of the epoxy when exposed to UV light for extended periods of time. ***Testing*** • The tanks would be hydrostatically tested with water in accordance with API 650 prior to turn over to the Owner.

Topic	Discussion
	• This water will require a permit from ADEC and the City in order to discharge it to the city sewer system.
Rail Offloading	***Rate*** • 600 gallons of ULSD per minute per railcar • Ability to unload two rail cars simultaneously ***Rail Spurs*** • Based on 55'-7-1/8" Tanker Cars (23,500 gallons per car) used at FHR • No. 11 switch from main railroad track • No. 9 switches on rail spurs • Parallel rail spurs to stage railcars for the offloading process. • Gated at eastern end of primary GVEA rail spur • Capacity for 20 railcars in Alternatives 1 & 3 • Reducedcapacity 18 railcars in Alternative 2 ***Rail Unloading Rack*** • Heated building for personnel and fuels equipment and metering/operations • Design spill containment: 30,000 gallons • Trackmobile used to stage railcars during unloading operations • Heated building at west end of rail spur for Track mobile storage and maintenance • Capacity of 470,000 gallons of fuel per delivery in Alternatives 1 & 3 • Capacity of 423,000 gallons of fuel per delivery in Alternative 2 ***Piping*** • One directional flow from unloading rack • Process piping will run between the rail spur with inlet points directed to each of the two rail spur lines. • Avoid running pipes beneath rails if possible • Multiple 10-inch pipelines from rail rack to filtration equipment for redundancy. • All fuel received will pass through filtration equipment consisting of particulate filters prior to entering the storage tanks. ***Oily Water Collection System*** • System of sumps beneath rail unloading rack will collect spills and pass through a central OWS which also will handle oily water from tank farm and truck loading racks before discharging into the industrial wastewater line along H&H Road. ***Trackmobile Building (New)*** • The Trackmobile building will be an approximately 30'x45' structure with a concrete slab on grade capable to support the weight of the Trackmobile unit. • The walls will be CMU block. • Eave height will be approximately 18 feet to allow for an approximate 14'Wx16'H overhead door. • Roof to be wood trusses on 3:12 pitch. • Install 2-ton underhung trolley

Topic	Discussion
	• Building heat to come from shared heat of Control Room Building and Pump House Building ***GVEA Rail Facility Warm-Up Hut (New)*** • Warm-up hut to be 8'x12' wood framed building with concrete slab on grade floor • Walls to be supported by thickened edge slab • Eave height will be approximately 8' • Roof will consist of wood trusses with 4:12 pitch • Building will have single man door and three windows on non-door walls • Building to have electric heat
Truck Loading and Unloading	***General Description*** • Designed to accommodate two (2) "A-Train" double fuel tanker truck configurations for both fuel loading/unloading simultaneously at 600 GPM each • 40 foot minimum turning radius • Two fueling positions for ULSD. Naphtha will not be sent or received by truck. • Currently we have the costs captured to: 1) Offload two tankers simultaneously. 2) Load two tankers simultaneously 3) Offload and load two tankers simultaneously with the same product. • Located adjacent to a concrete drive-on lane, that is depressed in its center to provide the code required containment during transfers. • This concrete slab would be heat traced to allow removal of ice in winter. Waste heat with heating source will be used. • Sump will connect to oily water collection system, pass through a central OWS, which also connects to the tank farm and the rail rack, and then discharge into the industrial wastewater line along H&H Road. • The truck loading rack would not be covered and no structure is included. • The system would contain the necessary primary and secondary shutoff valves, metering, overfill prevention system, drive-off protection, and terminal management system. • Each loading station on the truck loading rack would consist of a meter with a totalizer and reset. • A flow control valve would be used to control the flow into the tanker trucks to a set point and would provide the dead-man shutoff point. ***Loading*** • Loading product will be drawn from the respective tank, through a service header pipeline and into the suction of the diesel supply pumps located in the pump building. The fuel will be pumped to the Truck Loading Rack. • The system would also include an overfill prevention system. We have assumed that vapor recovery is not required, and do not believe that it is due to the relatively small throughput planned for the facility • Two loading arms ***Offloading***

Topic	Discussion
	• Offloading would consist of a 4-inch hose feeding an 8-inch pipeline that leads into the suction of the offloading pump in the pump building.
Waste Heat	• To add efficiencies into this project, waste heat from NPEP will be used to heat structures and the truck loading slab, with secondary source to be used when the turbines are not in operation.
Facility Buildings	***Pump House/Filtration Building*** • 30'x40' CMU block with metal roof, insulated and heated • Waste heat used as primary heat source with backup secondary source • Clearance to other structures: Minimum 25 feet from loading/unloading racks and 14.17 feet from the tanks • Parking for maintenance staff • Foundation designed to contain fuel releases and drain them to a common collection area with the associated alarms to notify the facility operators. • Overhead door • Four (4) large centrifugal pumps, along with smaller transfer pumps with a combined horsepower of nominally 250 HP. • Steel piping, small volume product recovery system, valves, and vessels • A pair of filter trains located within the building to provide particulate and water removal as needed for incoming and outgoing fuel. • Overhead crane rail for equipment maintenance • Structural access walkways • Lighting and Equipment power • Ventilation • AFFF fire suppression system equipment • Controls suitable for use in a hazardous environment • All other associated services necessary to ensure safe and reliable function and access for maintenance and operations. ***Control Building (Controls, AFFF, Maintenance, and Storage Building)*** • 30'x40' CMU block with metal roof, insulated and heated • Waste heat used as primary heat source with backup secondary. • Clearance to other structures: Minimum 25 feet from loading/unloading racks and 14.17 feet from the tanks • Parking for office and maintenance staff • Single office shared fuels control room • Single unisex bathroom • Water, sewer, and electrical service • Heated fueling support equipment storage with overhead door • Mechanical room • Concrete foundation that is designed to suit the soil conditions and is based on the outcome of the geotechnical soils report. Spread Footing and stem wall on improved ground located below frost line is typical. • The offices would be finished in typical office environment fashion and in

Topic	Discussion
	accordance with the occupancy requirements determined by the International Building Code, and will contain document storage • The shop and storage areas of the building would consist of relatively unfinished interiors typical of maintenance and storage shops in arctic environments, and will contain spare parts associated with the facility • The fuel quality control lab would have the necessary ventilation hoods, and the necessary lab equipment would be adequately supported by the building infrastructure, i.e. power, lighting, heat, and ventilation.
Fuel Metering and Quality Assurance	• Liquid metering systems will be provided for all fuels entering and leaving GVEA custody. Meters will be used to deliver a determined flow rate and comply with standard local and federal codes for fuel handling. • Instrumentation will be Ovation or compatible with Ovation as part of the Terminal Management System. Meters will be periodically tested with a prover system to ensure they accurately record the quantity of fuels transferred. • Fuels quality will be assured through on-site laboratory analysis. The fuels quality control lab will be located in the control building and have the necessary equipment to verify all fuel cargo and inventory meet the standards required, particularly for low sulfur fuel.
Fuel Piping	• See attached pipe schedule. • All fuel piping will be ASTM A53 Gr. B, Sch. 40 steel pipe rated for an ANSI Class 150 system. • Piping will be fabricated and installed in accordance with ASME B31.3 standards for welding and NDE requirements. • All piping will include a three (3) coat exterior field coating consisting of an appropriate epoxy system with a urethane topcoat to prevent chalking and UV degradation where exposed. • Cathodic protection will be provided. The selection will take into account the proximity of existing piping and its interaction. This will likely be a passive anode system. • Piping systems shall be buried where appropriate, adequately supported when aboveground, and designed to withstand the maximum stresses in accordance with ASME required load combinations such as pressure, thermal expansion, gravity loads and seismic loading. • Pipe Slopes – o Fuel piping will be graded to slope towards drain points for defueling lines for maintenance where possible. o Offloading piping will be sloped towards pump to allow for system clearing between cargo deliveries. o AFFF piping shall be sloped to meet code with low point drains.
Security	***Access Control – Physical and Electronic*** • Chain link fence with minimum fabric height of 7 feet around tank farm, rail and truck facility. All perimeter fence shall be topped with razor wire.

Topic	Discussion
	• Crash barriers as required by industry best practices • Powered gates will be provided at all access points to tank farm, truck and rail facility, and North Pole Expansion Plant Campus • Personnel gates • Door Hardware – Best type "TC" keying standard • Electronic access at building entrances: Proximity – close read which is currently used at GVEA. • Electronic access at vehicle gates: Proximity – large gap read range which is currently used at GVEA. • Electronic access at locations where additional verification level is desired: Proximity with PIN to open the door without an alarm. ***CCTV Surveillance*** • 4 Megapixel video monitoring at vehicle gates, building entrances, pump control rooms, perimeter fence, truck loading area, and at the tank farm near controls and valves • 3-7 day local video storage if central connection disrupted • Centralized security monitoring office located in the Illinois Street headquarters campus with redundant monitoring available at North Pole Expansion Plant. • Central storage facility that is expandable • Duration of video saved: 30 days ***Intrusion Detection*** • Perimeter motion detection (infrared) • Wide gap balanced magnetic switches used at gates and overhead doors which are less susceptible to spoofing • Magnetic door contracts for interior applications • Motion detection (Infrared) used as backup for magnetic door contracts ***Alarming and Monitoring*** • Central alarm • Central logging • Remote alarm monitoring; since the facility is monitored remotely, this is preferred to dispatch police to detain potential trespassers.
Electrical	• The largest facility loads will be the fuel transfer pumps located in the pump building. • Facility lighting would be installed to provide illumination necessary for operators to have safe access for maintenance and routine functions. • All lighting would likely utilize LED fixtures and will strictly adhere to dark-sky requirements and airport regulations. • Below-grade conduit runs will be routed from the tank farm electrical to a main distribution point at a location to be determined. • Hazardous Area Classification will need to be defined and the device ratings would comply with the NEC regulations relative to their locations.

Topic	Discussion
Controls	• Controls shall be integrated into the facility operations by means of a packaged Terminal Management System (TMS) compliant with the current Ovation system in operation at GVEA. • Any auxiliary controls required to control functions unique to the fuels facility is assumed to be compatible with the existing Ovation system. • Electrical controls required for the tank farm include data transmission from the tank auto gauge system, level and pump flow switches, and alarms. • Additional tank alarms will consist of a high-high level alarm, low level alarm and level indication based on the gauging system. • The conduit, devices and wiring required for the installation will be listed intrinsically safe in accordance with NEC requirements.
Fire Suppression	• Fire Marshal requires that any diesel tank that exceeds 1500 SF (a 364,000 gallon tank about 44 feet diameter) of fuel surface area requires an AFFF system. • Aqueous Film Forming Foam (AFFF) system will be supplied and housed in the Control Building. • The system will be automated. • The AFFF system would consist of foam water supply pipelines that originate in the AFFF room of the Control Building and are routed to shell mounted foam chambers on each tank. • The AFFF supply manifold, located in the AFFF building, would be designed for the future expansion and have provisions for the new supply lines to any new tanks. • The pipe would be painted galvanized steel. All piping would be constructed in accordance with industry standards for welding and NDE requirements. • The piping would be supported from the tank shell as required with welded tabs installed by the tank fabricator. • All piping would also include a three-coat exterior field coating consisting of an appropriate epoxy system with a urethane topcoat to prevent chalking and UV degradation. • The perimeter AFFF system would consist of foam water supply pipelines that originate in the pump house building and are routed around the perimeter of the tank farm on the outside of the dike. • Hose connection points are located nominally every 200’ to allow for fire department connection in fighting tank fires from outside the containment area. • The piping would be supported on vertical supports as required along the dike.
Access Road	• New access road would allow GVEA to enter the NPEP and NPG from H&H Road without having to drive through Flint Hills or Petro Star. • Required to be built for Alternatives 1A and 1B • Not necessary to construct fuel storage for Alternatives 2 and 3 • Alignment chosen will provide room for a piping corridor between the road and existing infrastructure on the north. • 30-foot-wide paved access road west of H&H to GVEA North Pole Expansion Plant

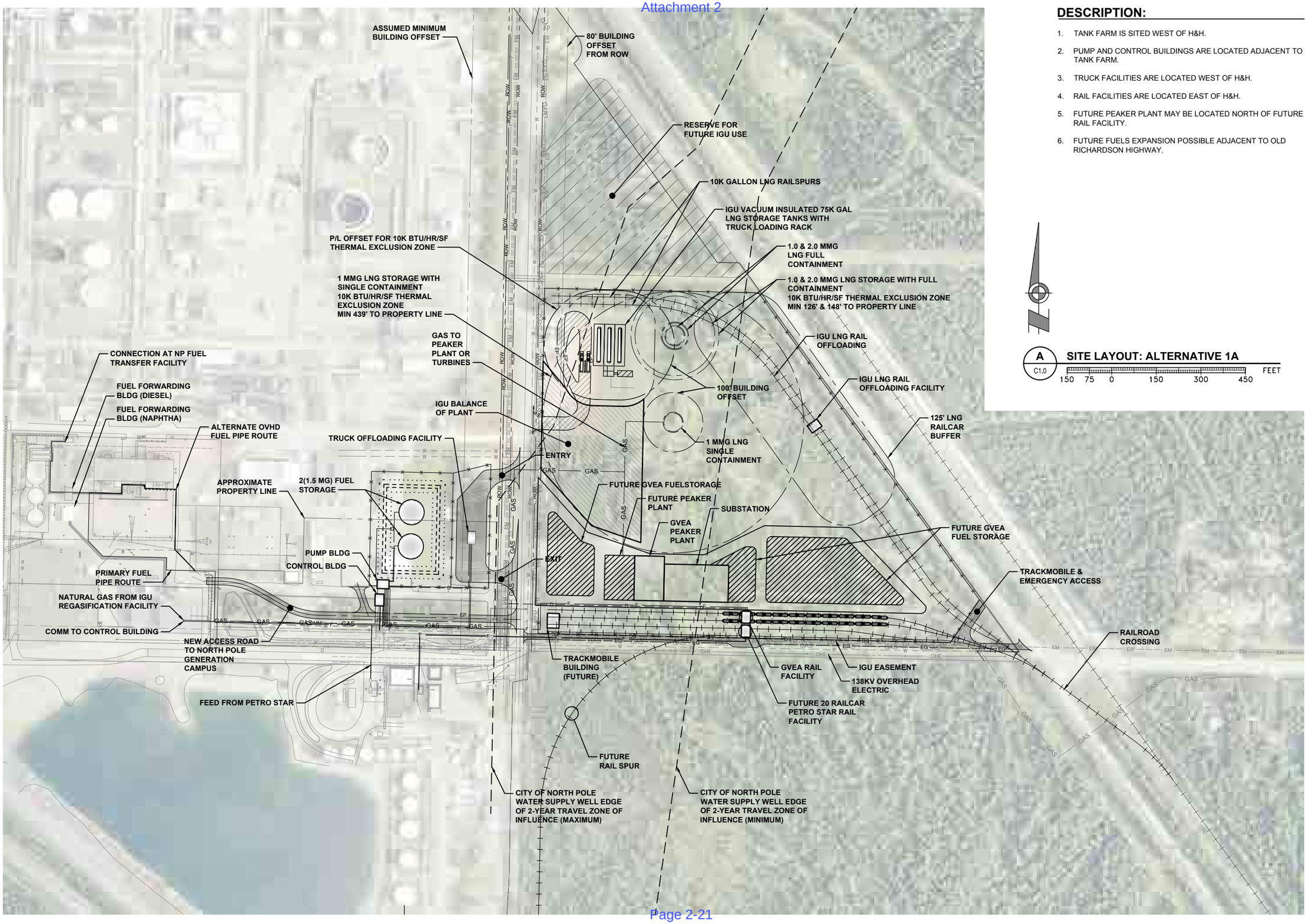
Topic	Discussion
	• Connects H&H to northwest corner of North Pole Expansion Plant yard • Gated at H&H Road
Future Peaker Plant	• Future Peaker Plant has been considered in all conceptual site layouts. ***Potential Location*** • North Pole Generation Campus and Illinois St. Campus have been considered for Peaker plant location. ***Sizing*** • Peaker plant size based on Four (4) Wärtsilä units • Future peaker plant expansion based on another Four (4) Wärtsilä units • Additional space allocated for future Peaker Plant expansion • Substation size is based on other substations located nearby ***Fuel Consumption Rates*** • ULSD: 580 gallons/hr/Wärtsilä unit • Natural Gas: 70,000 scf/hr @ 85 psig + 6 gallons ULSD/hr/Wärtsilä unit
IGU	***LNG Storage Needs*** • Short Term (3 years for phases 1-3): ..... 150k Gallon Storage • Long Term (>3 years to meet long term growth): .. 700k Gallon Storage • Ultimate: 1.0 MMG Storage ***Offsets to Property Line and Buildings for 10,000 BTU/hr/square foot LNG Tank Thermal Exclusion Zone*** • Short Term 75k Gallon horizontal tanks with N+1 Availability: 184-foot radius • 1.0 MMG Single Containment: ..... 439' radius • 1.0 MMG Full Containment: ..... 134' radius ***Future Rail Unloading Facility*** • Parallel rail spurs to stage railcars for the LNG offloading process. • Gated at southern end of primary IGU rail spur • Shared road crossing with GVEA and Petro Star rail facilities • Offset from railcar to property line and buildings for 10,000 BTU/hr/square foot LNG tank thermal exclusion zone: 184 feet
Petro Star	***Pipelines*** • Existing Naphtha to GVEA • 10-inch steel pipeline from Petro Star to GVEA Fuel Forwarding building • Future pipeline to Petro Star Rail Loading Facility ***Future Rail Loading*** • Parallel rail spurs to stage railcars for loading and unloading 20 rail cars • Gated at eastern end of primary Petro Star rail spur • Shared road crossing with GVEA and IGU rail facilities
Soils and	• Relatively flat terrain

Topic	Discussion
Topography	• 2-10 feet of silty soils underlain with sandy gravel and gravels at depth. • High groundwater table, 2-12 feet BGS • High potential for liquefaction settlement during seismic event • No permafrost encountered in preliminary soils exploration

Attachments:

1. Piping Schedule by GNE

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DESCRIPTION:

1. TANK FARM IS SITED WEST OF H&H.
2. PUMP AND CONTROL BUILDINGS ARE LOCATED ADJACENT TO TANK FARM.
3. TRUCK FACILITIES ARE LOCATED WEST OF H&H.
4. RAIL FACILITIES ARE LOCATED EAST OF H&H.
5. FUTURE PEAKER PLANT MAY BE LOCATED NORTH OF FUTURE RAIL FACILITY.
6. FUTURE FUELS EXPANSION POSSIBLE ADJACENT TO OLD RICHARDSON HIGHWAY.

A C1.0 **SITE LAYOUT: ALTERNATIVE 1A**

150 75 0 150 300 450 FEET

CONSULTANT :

PDC ENGINEERS
PLAN • DESIGN • CONSTRUCT
1028 Aurora Drive, Fairbanks, Alaska 99709
907.452.1414 | AECC605

PROJECT :
GOLDEN VALLEY ELECTRIC ASSOCIATION
3M GALLON STORAGE TANK FOR NORTH POLE GENERATION CAMPUS
NORTH POLE, ALASKA

SHEET TITLE :
SITE LAYOUT
ALTERNATIVE 1A
CONCEPT DEVELOPMENT

DESIGN	DES
DRAWN	RJP
CHECKED	KAB
DATE	JUNE 28, 2017

PROJECT No. 17099FB

SHEET NUMBER C1.0 OF . SHEETS

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DESCRIPTION:

1. TANK FARM IS SITED WEST OF H&H.
2. PUMP AND CONTROL BUILDINGS ARE LOCATED ADJACENT TO TANK FARM.
3. TRUCK AND RAIL FACILITIES ARE LOCATED EAST OF H&H.
4. FUTURE PEAKER PLANT MAY BE LOCATED NORTH OF FUTURE RAIL FACILITY.
5. FUTURE FUELS EXPANSION POSSIBLE ADJACENT TO OLD RICHARDSON HIGHWAY.

A C1.1 **SITE LAYOUT: ALTERNATIVE 1B**

150 75 0 150 300 450 FEET

ASSUMED MINIMUM BUILDING OFFSET
80' BUILDING OFFSET FROM ROW
RESERVE FOR FUTURE IGU USE
10K GALLON LNG RAILSPURS
IGU VACUUM INSULATED 75K GAL LNG STORAGE TANKS WITH TRUCK LOADING RACK
P/L OFFSET FOR 10K BTU/HR/SF THERMAL EXCLUSION ZONE
1.0 & 2.0 MMG LNG FULL CONTAINMENT
1 MMG LNG STORAGE WITH SINGLE CONTAINMENT 10K BTU/HR/SF THERMAL EXCLUSION ZONE MIN 439' TO PROPERTY LINE
1.0 & 2.0 MMG LNG STORAGE WITH FULL CONTAINMENT 10K BTU/HR/SF THERMAL EXCLUSION ZONE MIN 126' & 148' TO PROPERTY LINE
GAS TO PEAKER PLANT OR TURBINES
IGU LNG RAIL OFFLOADING
CONNECTION AT NP FUEL TRANSFER FACILITY
FUEL FORWARDING BLDG (DIESEL)
FUEL FORWARDING BLDG (NAPHTHA)
100' BUILDING OFFSET
IGU LNG RAIL OFFLOADING FACILITY
IGU BALANCE OF PLANT
125' LNG RAILCAR BUFFER
ALTERNATE OVHD FUEL PIPE ROUTE
1 MMG LNG SINGLE CONTAINMENT
ENTRY
APPROXIMATE PROPERTY LINE
2(1.5 MG) FUEL STORAGE
TRUCK OFFLOADING FACILITY
FUTURE PEAKER PLANT
SUBSTATION
GVEA PEAKER PLANT
FUTURE GVEA FUEL STORAGE
PUMP BLDG
EXIT
TRACKMOBILE & EMERGENCY ACCESS
PRIMARY FUEL PIPE ROUTE
NATURAL GAS FROM IGU REGASIFICATION FACILITY
COMM TO CONTROL BUILDING
NEW ACCESS ROAD TO NORTH POLE GENERATION CAMPUS
CONTROL BLDG
TRACKMOBILE BUILDING (FUTURE)
RAILROAD CROSSING
GVEA RAIL FACILITY
IGU EASEMENT
138KV OVERHEAD ELECTRIC
FEED FROM PETRO STAR
FUTURE 20 RAILCAR PETRO STAR RAIL FACILITY
FUTURE RAIL SPUR
CITY OF NORTH POLE WATER SUPPLY WELL EDGE OF 2-YEAR TRAVEL ZONE OF INFLUENCE (MAXIMUM)
CITY OF NORTH POLE WATER SUPPLY WELL EDGE OF 2-YEAR TRAVEL ZONE OF INFLUENCE (MINIMUM)

CONSULTANT :

PDC ENGINEERS
PLAN • DESIGN • CONSTRUCT
1028 Aurora Drive, Fairbanks, Alaska 99709
907.452.1414 | AECC605

PROJECT :
GOLDEN VALLEY ELECTRIC ASSOCIATION
3M GALLON STORAGE TANK FOR NORTH POLE GENERATION CAMPUS
NORTH POLE, ALASKA

SHEET TITLE :
SITE LAYOUT
ALTERNATIVE 1B
CONCEPT DEVELOPMENT

DESIGN	DES
DRAWN	RJP
CHECKED	KAB
DATE	JUNE 28, 2017

PROJECT No. 17099FB

SHEET NUMBER C1.1 OF . SHEETS

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DESCRIPTION:

1. TANK FARM IS SITED EAST OF H&H.
2. PUMP AND CONTROL BUILDINGS ARE LOCATED IN-BETWEEN THE TANK FARM AND H&H.
3. TRUCK AND RAIL FACILITIES ARE LOCATED EAST OF H&H.
4. FUTURE PEAKER PLANT MAY BE LOCATED WEST OF H&H, CLOSER TO THE NORTH POLE EXPANSION PLANT.
5. FUTURE FUELS EXPANSION POSSIBLE ADJACENT TO OLD RICHARDSON HIGHWAY.

A C2.0 **SITE LAYOUT: ALTERNATIVE 2**

150 75 0 150 300 450 FEET

ASSUMED MINIMUM BUILDING OFFSET
80' BUILDING OFFSET FROM ROW
RESERVE FOR FUTURE IGU USE
10K GALLON LNG RAILSPURS
IGU VACUUM INSULATED 75K GAL LNG STORAGE TANKS WITH TRUCK LOADING RACK
P/L OFFSET FOR 10K BTU/HR/SF THERMAL EXCLUSION ZONE
1.0 & 2.0 MMG LNG FULL CONTAINMENT
1 MMG LNG STORAGE WITH SINGLE CONTAINMENT 10K BTU/HR/SF THERMAL EXCLUSION ZONE MIN 439' TO PROPERTY LINE
1.0 & 2.0 MMG LNG STORAGE WITH FULL CONTAINMENT 10K BTU/HR/SF THERMAL EXCLUSION ZONE MIN 126' & 148' TO PROPERTY LINE
IGU LNG RAIL OFFLOADING
CONNECTION AT NP FUEL TRANSFER FACILITY
FUEL FORWARDING BLDG (DIESEL)
FUEL FORWARDING BLDG (NAPHTHA)
ALTERNATE OVHD FUEL PIPE ROUTE
100' BUILDING OFFSET
IGU LNG RAIL OFFLOADING FACILITY
IGU BALANCE OF PLANT
125' LNG RAILCAR BUFFER
FUTURE PLANT EXPANSION
GAS TO PEAKER PLANT OR TURBINES
1 MMG LNG SINGLE CONTAINMENT
GVEA PEAKER PLANT
ENTRY
100' BUILDING OFFSET
APPROXIMATE PROPERTY LINE
CONTROL BLDG
PUMP BLDG
SUBSTATION
TRUCK OFFLOADING FACILITY
2(1.5 MG) FUEL STORAGE
PEAKER PLANT ACCESS
FUTURE GVEA FUEL STORAGE
TRACKMOBILE & EMERGENCY ACCESS
PRIMARY FUEL PIPE ROUTE
EXIT
NATURAL GAS FROM IGU REGASIFICATION FACILITY
RAILROAD CROSSING
COMM TO CONTROL BUILDING
NEW ACCESS ROAD TO NORTH POLE GENERATION CAMPUS
TRACKMOBILE BUILDING (FUTURE)
GVEA RAIL FACILITY
IGU EASEMENT
138KV OVERHEAD ELECTRIC
FEED FROM PETRO STAR
FUTURE 20 RAILCAR PETRO STAR RAIL FACILITY
FUTURE RAIL SPUR
CITY OF NORTH POLE WATER SUPPLY WELL EDGE OF 2-YEAR TRAVEL ZONE OF INFLUENCE (MAXIMUM)
CITY OF NORTH POLE WATER SUPPLY WELL EDGE OF 2-YEAR TRAVEL ZONE OF INFLUENCE (MINIMUM)

CONSULTANT :

PDC ENGINEERS
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PROJECT :
GOLDEN VALLEY ELECTRIC ASSOCIATION
3M GALLON STORAGE TANK FOR NORTH POLE GENERATION CAMPUS
NORTH POLE, ALASKA

SHEET TITLE :
SITE LAYOUT ALTERNATIVE 2
CONCEPT DEVELOPMENT

DESIGN	DES
DRAWN	RJP
CHECKED	KAB
DATE	JUNE 28, 2017

PROJECT No. 17099FB
SHEET NUMBER C2.0
OF . SHEETS

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DESCRIPTION:

1. SIMILAR TO ALTERNATIVE 2, TANK FARM IS SITED EAST OF H&H.
2. PUMP AND CONTROL BUILDINGS ARE LOCATED IN-BETWEEN THE TANK FARM AND H&H.
3. TRUCK AND RAIL FACILITIES ARE LOCATED EAST OF H&H.
4. FUTURE PEAKER PLANT MAY BE LOCATED WEST OF H&H, CLOSER TO THE NORTH POLE EXPANSION PLANT.
5. FUTURE FUELS EXPANSION POSSIBLE TO THE WEST OF THE TANK FARM.

A C3.0 **SITE LAYOUT: ALTERNATIVE 3**

150 75 0 150 300 450 FEET

ASSUMED MINIMUM BUILDING OFFSET
80' BUILDING OFFSET FROM ROW
RESERVE FOR FUTURE IGU USE
10K GALLON LNG RAILSPURS
IGU VACUUM INSULATED 75K GAL LNG STORAGE TANKS WITH TRUCK LOADING RACK
P/L OFFSET FOR 10K BTU/HR/SF THERMAL EXCLUSION ZONE
1.0 & 2.0 MMG LNG FULL CONTAINMENT
1 MMG LNG STORAGE WITH SINGLE CONTAINMENT 10K BTU/HR/SF THERMAL EXCLUSION ZONE MIN 439' TO PROPERTY LINE
1.0 & 2.0 MMG LNG STORAGE WITH FULL CONTAINMENT 10K BTU/HR/SF THERMAL EXCLUSION ZONE MIN 126' & 148' TO PROPERTY LINE
GAS TO PEAKER PLANT OR TURBINES
CONNECTION AT NP FUEL TRANSFER FACILITY
FUEL FORWARDING BLDG (DIESEL)
FUEL FORWARDING BLDG (NAPHTHA)
ALTERNATE OVHD FUEL PIPE ROUTE
100' BUILDING OFFSET
IGU LNG RAIL OFFLOADING FACILITY
IGU BALANCE OF PLANT
125' LNG RAILCAR BUFFER
FUTURE PLANT EXPANSION
1 MMG LNG SINGLE CONTAINMENT
100' BUILDING OFFSET
GVEA PEAKER PLANT
ENTRY
CONTROL BLDG
APPROXIMATE PROPERTY LINE
PUMP BLDG
FUTURE GVEA FUEL STORAGE
2(1.5 MG) FUEL STORAGE
TRUCK OFFLOADING FACILITY
SUBSTATION
PEAKER PLANT ACCESS
TRACKMOBILE & EMERGENCY ACCESS
PRIMARY FUEL PIPE ROUTE
EXIT
NATURAL GAS FROM IGU REGASIFICATION FACILITY
RAILROAD CROSSING
COMM TO CONTROL BUILDING
NEW ACCESS ROAD TO NORTH POLE GENERATION CAMPUS
TRACKMOBILE BUILDING (FUTURE)
GVEA RAIL FACILITY
IGU EASEMENT
138KV OVERHEAD ELECTRIC
FUTURE 20 RAILCAR PETRO STAR RAIL FACILITY
FEED FROM PETRO STAR
FUTURE RAIL SPUR
CITY OF NORTH POLE WATER SUPPLY WELL EDGE OF 2-YEAR TRAVEL ZONE OF INFLUENCE (MAXIMUM)
CITY OF NORTH POLE WATER SUPPLY WELL EDGE OF 2-YEAR TRAVEL ZONE OF INFLUENCE (MINIMUM)

CONSULTANT :

PDC ENGINEERS
PLAN • DESIGN • CONSTRUCT
1028 Aurora Drive, Fairbanks, Alaska 99709
907.452.1414 | AECC605

PROJECT :
GOLDEN VALLEY ELECTRIC ASSOCIATION
3M GALLON STORAGE TANK FOR NORTH POLE GENERATION CAMPUS
NORTH POLE, ALASKA

SHEET TITLE :
SITE LAYOUT ALTERNATIVE 3
CONCEPT DEVELOPMENT

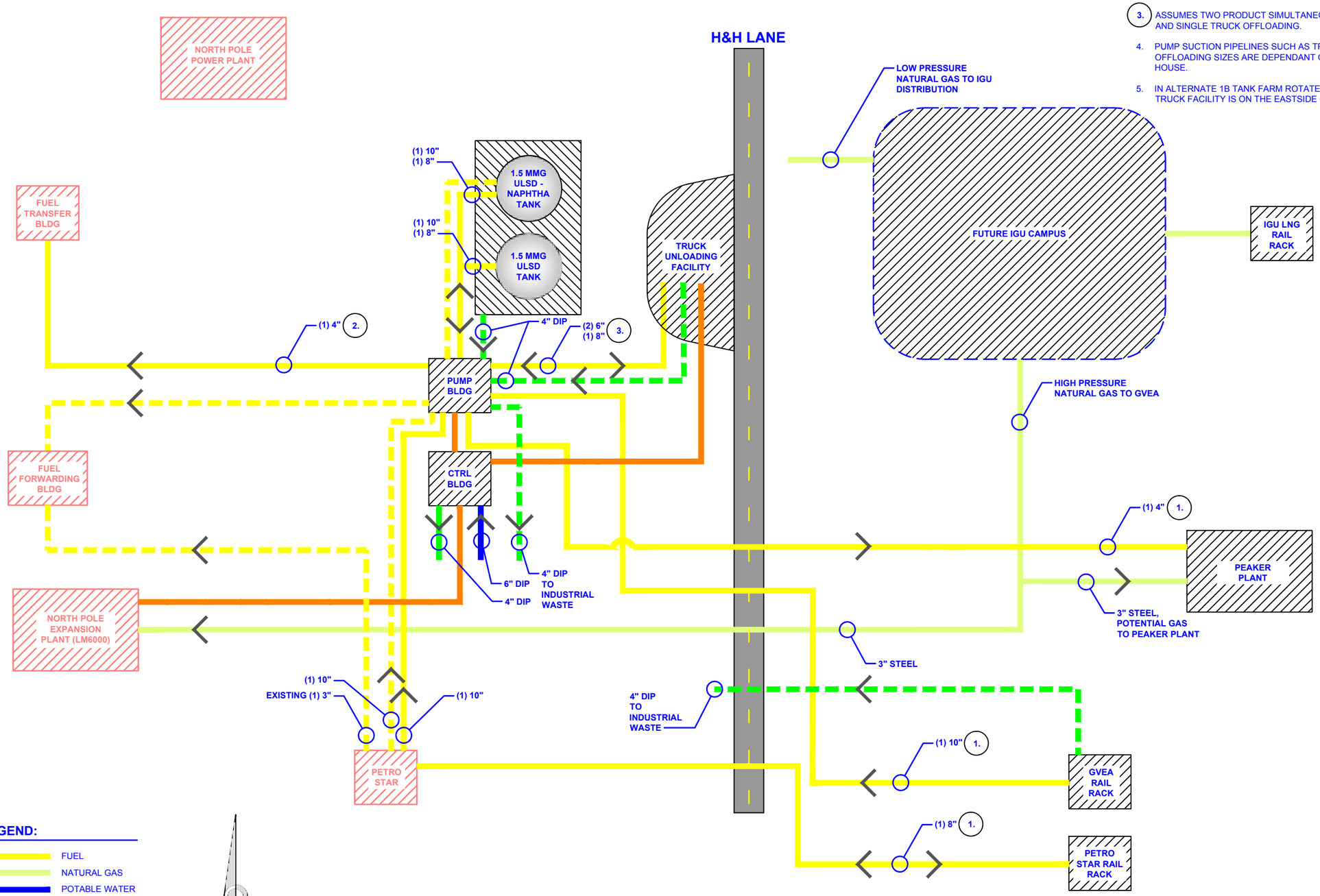
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DATE	JUNE 28, 2017
PROJECT No.	17099FB
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NOTES:

1. ASSUMES SINGLE PIPELINE CAN BE USED FOR ALL PRODUCTS.
2. SIZE ASSUMED BASED ON MAX FLOW RATE OF APPROXIMATELY 400 GPM.
3. ASSUMES TWO PRODUCT SIMULTANEOUS TRUCK LOADING, AND SINGLE TRUCK OFFLOADING.
4. PUMP SUCTION PIPELINES SUCH AS TRUCK AND RAIL OFFLOADING SIZES ARE DEPENDANT ON DISTANCE TO PUMP HOUSE.
5. IN ALTERNATE 1B TANK FARM ROTATED 90 DEGREES AND TRUCK FACILITY IS ON THE EASTSIDE OF H&H.



LEGEND:

- FUEL
- NATURAL GAS
- POTABLE WATER
- SEWER / STORM
- COMM
- OILY WATER
- NAPHTHA

CONSULTANT :

PDC Engineers
1028 Aurora Drive, Fairbanks, Alaska 99709
907.452.1414 | AECC605

PROJECT : GOLDEN VALLEY ELECTRIC ASSOCIATION
3M GALLON STORAGE TANK FOR NORTH POLE GENERATION CAMPUS
NORTH POLE, ALASKA

SHEET TITLE : SCHEMATIC - FUEL PIPING ALTERNATIVE 1A
CONCEPT DEVELOPMENT

DESIGN	DES
DRAWN	RJP
CHECKED	KAB
DATE	JUNE 28, 2017

PROJECT No. 17099FB

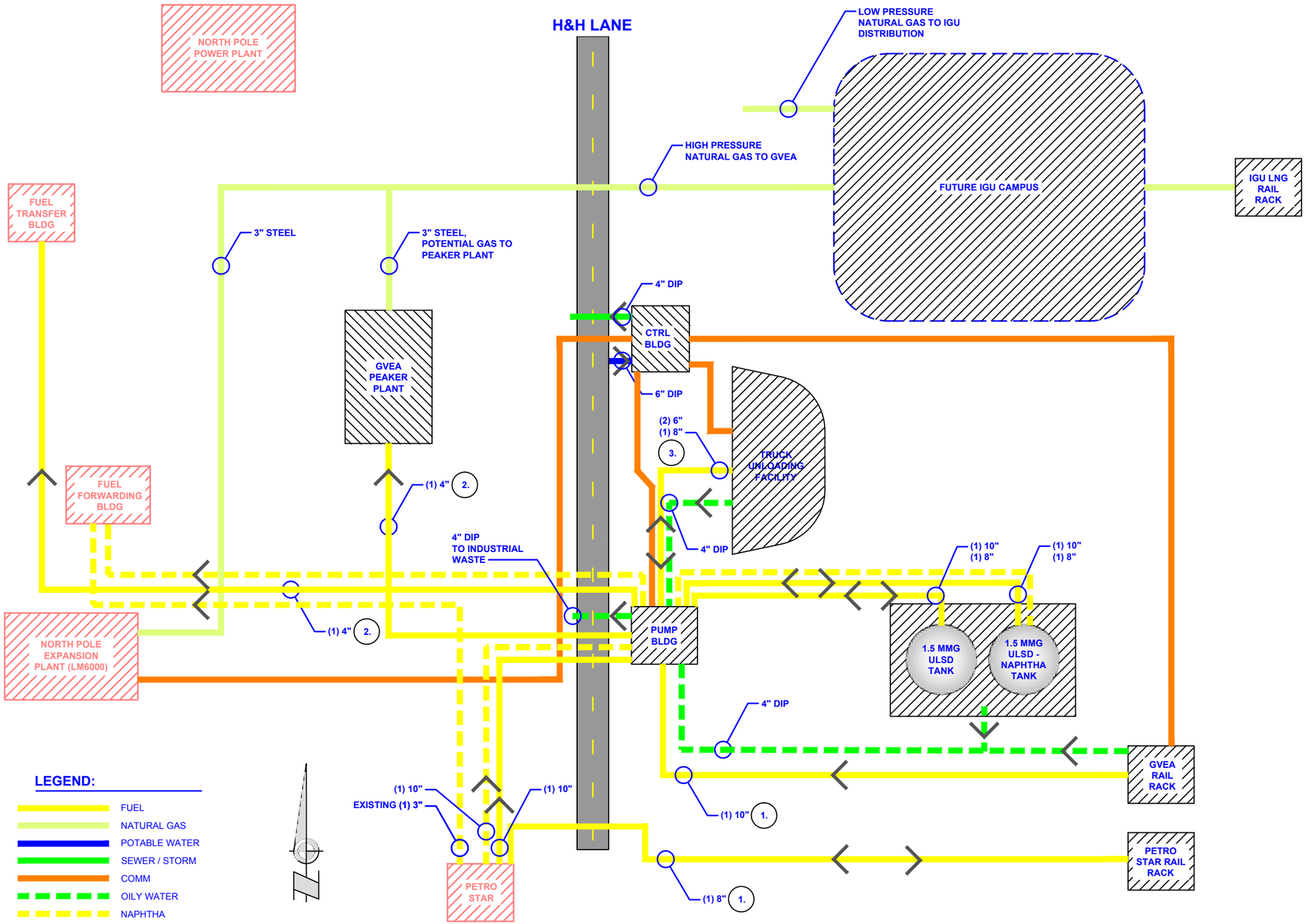
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NOTES:

1. ASSUMES SINGLE PIPELINE CAN BE USED FOR ALL PRODUCTS.
2. SIZE ASSUMED BASED ON MAX FLOW RATE OF APPROXIMATELY 400 GPM.
3. ASSUMES TWO PRODUCT SIMULTANEOUS TRUCK LOADING, AND SINGLE TRUCK OFFLOADING.
4. PUMP SUCTION PIPELINES SUCH AS TRUCK AND RAIL OFFLOADING SIZES ARE DEPENDANT ON DISTANCE TO PUMP HOUSE.



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CONSULTANT :

PDC Engineers
1028 Aurora Drive, Fairbanks, Alaska 99709
907.452.1414 | AECC605

PROJECT :
GOLDEN VALLEY ELECTRIC ASSOCIATION
3M GALLON STORAGE TANK FOR NORTH POLE GENERATION CAMPUS
NORTH POLE, ALASKA

SHEET TITLE :
SCHEMATIC - FUEL PIPING ALTERNATIVE 2
CONCEPT DEVELOPMENT

DESIGN	DES
DRAWN	RJP
CHECKED	KAB
DATE	JUNE 28, 2017

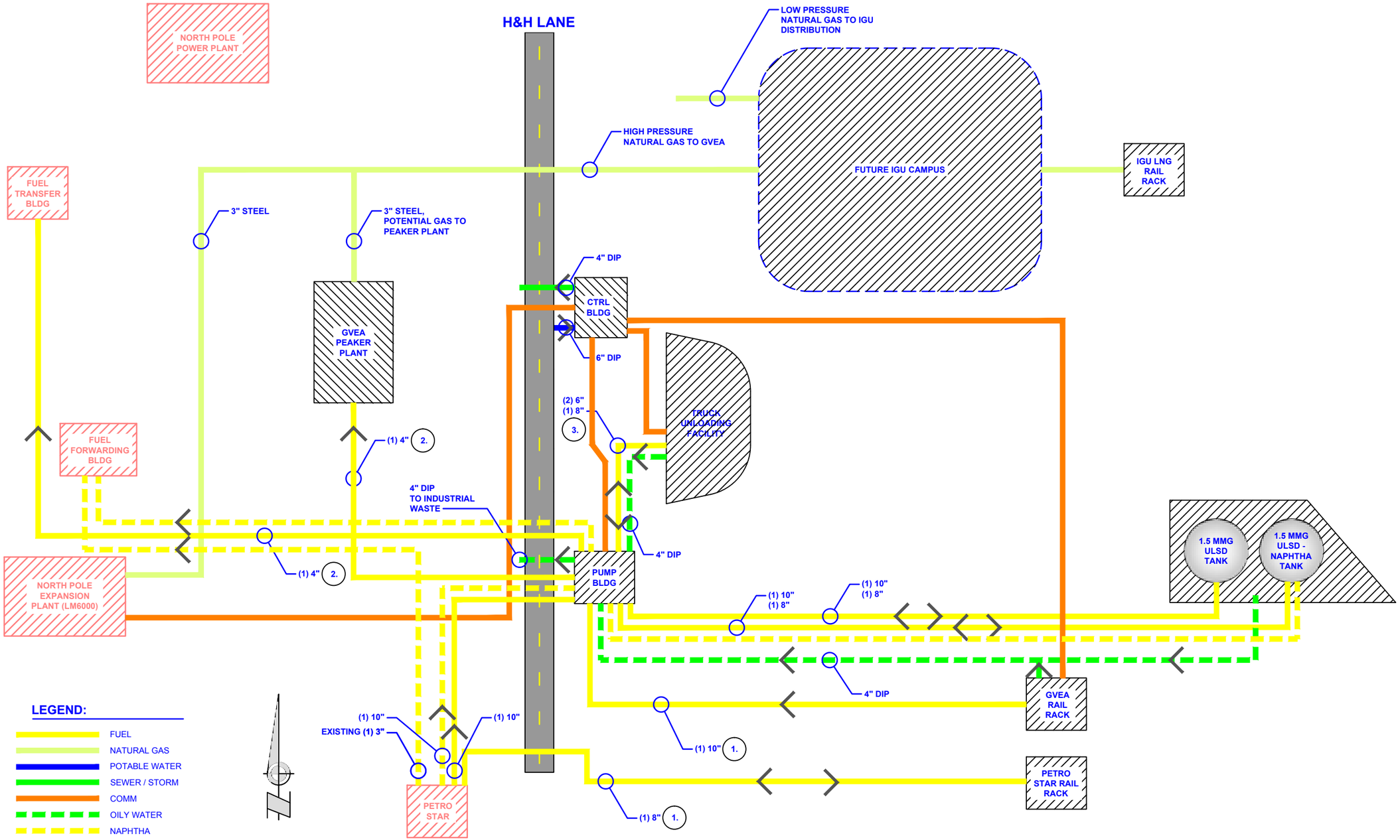
PROJECT No.
17099FB

SHEET NUMBER
C2.3
OF - SHEETS

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NOTES:

1. ASSUMES SINGLE PIPELINE CAN BE USED FOR ALL PRODUCTS.
2. SIZE ASSUMED BASED ON MAX FLOW RATE OF APPROXIMATELY 400 GPM.
3. ASSUMES TWO PRODUCT SIMULTANEOUS TRUCK LOADING, AND SINGLE TRUCK OFFLOADING.
4. PUMP SUCTION PIPELINES SUCH AS TRUCK AND RAIL OFFLOADING SIZES ARE DEPENDANT ON DISTANCE TO PUMP HOUSE.



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CONSULTANT :

PDC Engineers
1028 Aurora Drive, Fairbanks, Alaska 99709
907.452.1414 | AECC605

PROJECT :
GOLDEN VALLEY ELECTRIC ASSOCIATION
3M GALLON STORAGE TANK FOR NORTH POLE GENERATION CAMPUS
NORTH POLE, ALASKA

SHEET TITLE :
SCHEMATIC - FUEL PIPING ALTERNATIVE 3
CONCEPT DEVELOPMENT

DESIGN	DES
DRAWN	RJP
CHECKED	KAB
DATE	JUNE 28, 2017

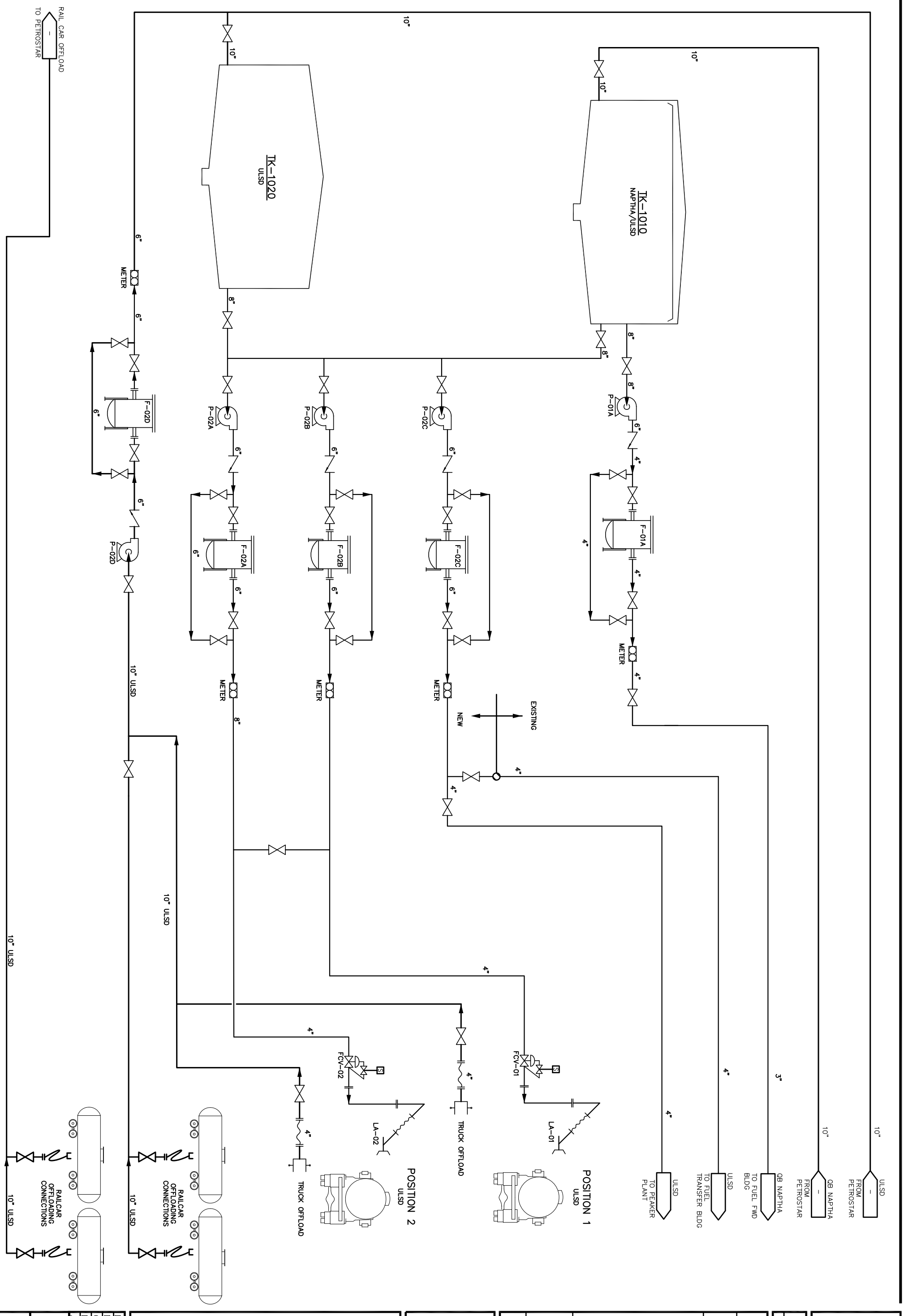
PROJECT No.
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SHEET NUMBER
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Attachment 2



B	06/27/17	ISSUED FOR REVIEW	DK	DK
REV	DATE	REVISION DESCRIPTION	DWN	CHK

DATE SIGNED

FLOW DIAGRAM
SYSTEM OVERVIEW
3MM GALLON TANK FARM
GOLDEN VALLEY ELECTRIC ASSOC.
NORTH POLE, ALASKA

GREAT NORTHERN ENGINEERING
1300 E. ARCTIC, SUITE 101
PALMER, AK 99645
(907) 745-6988

DATE: 05/26/17
DRAWN: JM
CHECKED: DK
DESIGNED: DK
APPROVED: DK

PD-01 DWG NO.
B REV.
17013 PROJECT NO.

LINE LIST

Line No.	Service	Description	From	To	Size (in)	Schedule	ANSI Class	Design Flow Rate (gpm)	Velocity (ft/s)	Dual Flow Direction (Y/N)
FA-010	ULSD	Truck Offload	Truck Load Rack	Pump Bldg	10	Std	150	1200	4.89	N
FA-020	ULSD	Truck Loading	Pump Bldg	Truck Load Rack	6	Std	150	600	6.79	N
FA-030	ULSD	Truck Loading	Pump Bldg	Truck Load Rack	6	Std	150	600	6.79	N
FA-040	ULSD	GVEA RR Offload	GVEA Rail Rack	Pump Bldg	10	Std	150	1200	4.89	N
FA-050	ULSD	Cargo from Petro Star	Petro Star Facility	Pump Bldg	10	Std	150	2000	8.15	N
FA-060	Naptha	Cargo from Petro Star	Petro Star Facility	Pump Bldg	10	Std	150	2000	8.15	N
FA-070	ULSD	Cargo to Tank 1	Pump Bldg	Tank 1	10	Std	150	1200	4.89	N
FA-080	ULSD	Service from Tank 1	Tank 1	Pump Bldg	8	Std	150	1200	7.64	N
FA-090	ULSD	Cargo to Tank 2	Pump Bldg	Tank 2	10	Std	150	1200	4.89	N
FA-100	ULSD	Service from Tank 2	Tank 2	Pump Bldg	8	Std	150	1200	7.64	N
FA-110	Naptha	Cargo to Tank 2	Pump Bldg	Tank 2	10	Std	150	1200	4.89	N
FA-120	Naptha	Service from Tank 2	Tank 2	Pump Bldg	8	Std	150	1200	7.64	N
FA-130	ULSD	Service to Fuel Transfer Bldg	Pump Bldg	Fuel Transfer Bldg	4	Std	150	400	10.19	N
FA-140	ULSD	Service to Peaker Plant	Pump Bldg	Peaker Plant	4	Std	150	400	10.19	N
FA-150	Naptha	Service to Fuel Fwd Bldg	Pump Bldg	Fuel Fowarding Bldg	3	Std	150	250	11.32	N
FA-160	ULSD	*Petro Star RR Load/Offload	Petro Star Rail Rack	Petro Star Facility	10	Std	150	1200	4.89	Y
FA-170	Naptha	**Service to Fuel Fwd Bldg	Petro Star Facility	Fuel Fowarding Bldg	3	Std	150	250	11.32	N

* This pipeline is NIC
** This pipeline is exsting and may be tied into outside of Fuel Forwarding Bldg

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

June 2017

Submitted To:
PDC Engineers, Inc.
1028 Aurora Drive
Fairbanks, Alaska 99709

By:

Shannon & Wilson, Inc.
2355 Hill Road
Fairbanks, Alaska 99709
AECC125

Phone: (907) 479-0600
Fax: (907) 479-5691

31-1-20006-001R1

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- 1.2 Scope of Services 2

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- 2.1 Field Exploration and Drilling Methods 3
- 2.2 Geotechnical Laboratory Testing 4

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FIGURE

1 Site Plan and Approximate Boring Locations

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A Soil Classification and Boring Logs
B Geotechnical Laboratory Data
C Project Photographs
D *Important Information About Your Geotechnical/Environmental Report*

GEOTECHNICAL FINDINGS REPORT
GVEA FUEL STORAGE FACILITY
NORTH POLE, ALASKA

1.0 INTRODUCTION

This report presents the results of our concept phase geotechnical services for the proposed fuel storage facility project in North Pole, Alaska. The purpose of our services was to explore subsurface conditions and provide a report of our geotechnical findings to assist in evaluation of conceptual site development plans.

Our services were performed consistent with our proposal dated February 17, 2017. Per your June 26, 2017 request, we have revised our report submitted on June 2, 2017 to include additional ground improvement discussion. This report was prepared for the exclusive use of PDC Engineers, Inc. and their representatives for the fuel storage tank project.

1.1 Project Understanding

We understand GVEA plans to construct a fuel-storage facility to support their power-generation plant in North Pole. GVEA requested a concept phase preliminary assessment of available land and development of three siting options. Future detailed design phases will be conducted to provide detailed exploration of the selected site and concept, and to prepare a final design of the fuel facility. This report presents the results of our concept phase preliminary explorations and a discussion of potential geotechnical site development and design concerns.

We understand two parcels are being considered for the fuel-storage facility site: the 33.8-acre Lot 2 of H&H Industrial Subdivision, and the southeast portion of Lot F1A of the ASLS 2003-50 Subdivision. Based on our previous discussions with GVEA, we also understand the southwest corner of Lot 2 has been considered a primary area of focus for this fuel storage development. We also understand these sites may include a future gasification plant and an additional power plant, as part of an energy campus.

The proposed fuel storage development is planned to include 3 million gallons of fuel storage, a surrounding catch basin, unloading area, and connection to the existing GVEA facility. The intent of this phase of services is to evaluate concepts plans and for site development, as well as to develop a preliminary geotechnical evaluation of likely geotechnical requirements for site development.

Our services are based on:

- The limitations of our approved scope, schedule, and budget.
- Our understanding of the project and information provided by Enterprise Engineering, Inc.
- The results of testing performed on samples we collected from the explorations.

The explorations were performed to evaluate geotechnical conditions at the project area. Our observations are specific to the locations, depths, and dates noted on the boring logs, and may not be applicable to all areas of the site. No amount of explorations or testing can precisely predict the characteristics, quality, or distribution of subsurface and site conditions. Potential variation includes, but is not limited to:

- The conditions between and below explorations may be different.
- The passage of time or intervening causes (natural and manmade) may result in changes to site and subsurface conditions.
- Groundwater levels and flow directions may fluctuate due to seasonal variations.
- Penetration test results in frozen or gravelly soils may be unrealistic. Actual soil density may be lower than estimated if the test was performed on a gravel or cobble.
- Contaminant concentrations may change in response to natural conditions, chemical reactions, and/or other event.
- The presence, distribution, and concentration of contaminants may vary from our sampling locations. Our tests may not represent the highest contaminant concentrations at the site.

If conditions different from those described herein are encountered during construction, we should review our description of the subsurface conditions and reconsider our recommendations and conclusions.

1.2 Scope of Services

Our scope of services included site subsurface explorations, geotechnical laboratory testing of select soil samples, preliminary liquefaction analyses, and preparation of this findings report.

The authorized scope of services was based on your objectives, schedule, and budget. Our scope of services did not include an environmental site assessment or wetland delineation for the project site, or for any of the contaminated sites near the proposed facility. It also did not include research or evaluating the presence of cultural resources at or around the site. If a service is not specifically indicated in this report, do not assume that it was performed.

2.0 FIELD EXPLORATION AND LABORATORY ANALYSES

Our field work consisted of drilling and sampling 5 exploratory borings, designated 17-01 through 17-05, within the proposed project area. Boring 17-01 through 17-04 were located on Lot 2 of H&H Subdivision and boring 17-05 was located on Lot F1A of the ASLS 2003-50 Subdivision. Field explorations were conducted between May 15, 2017 and May 18, 2017. We subcontracted Homestead Drilling of Fairbanks (Homestead) to perform the exploratory drilling.

Peter Grey, a geotechnical staff member with our firm, observed drilling operations, logged subsurface conditions, and collected geotechnical soil samples for soil classification and laboratory testing. The approximate location of the borings are shown in Figure 1; boring logs are presented in Appendix A.

2.1 Field Exploration and Drilling Methods

Homestead advanced the borings using a Mobile B61 track-mounted and Mobile B61 truck-mounted drill rig both of which were equipped with continuous-flight hollow-stem augers. Homestead advanced and sampled the borings to 61.5 feet below the ground surface (bgs). As the borings progressed, we generally collected a grab sample from the surface to 2 feet bgs, and split-spoon samples at 2.5-foot intervals to 20 feet bgs, 5 foot intervals to 50 feet, and 10 foot intervals thereafter, using a 2½-inch inside-diameter split-spoon sampler.

The split-spoon samples were obtained by driving the sampler into the soils at the base of the auger using a 340-pound automatic hammer falling 30 inches onto the drill rods. The number of blows required to advance the sampler 6 inches is recorded over three intervals, resulting in 18 inches of penetration. For each sample, the number of blows required to advance the sampler the final 12 inches is termed the penetration resistance, a measure of the relative consistency of unfrozen fine-grained soils and relative density of unfrozen granular soils. We classified soil samples recovered using these techniques in the field, sealed them in airtight containers, and returned them to our laboratory for testing.

We performed field screening of split-spoon samples above the groundwater table using a hand-held photoionization detector (PID). Soil observations and PID readings are included in the boring logs presented in Appendix A.

The explorations were performed to evaluate subsurface conditions at the site for the proposed fuel facility and associated structures. Our observations are specific to the locations, depths, and dates noted on the logs, and may not be applicable to all areas of the site.

2.2 Geotechnical Laboratory Testing

We visually reviewed field soil classifications in our laboratory and selected samples for testing. We performed moisture-content analyses on frozen samples and samples collected above the water table, and grain-size distribution analyses on select samples. Moisture-content results are plotted on the boring logs in Appendix A. Grain-size distribution curves are shown in Appendix B. Photographs of samples we collected are presented in Appendix C.

3.0 SITE CONDITIONS

3.1 Geological Setting

North Pole is within the Tanana Lowlands physiographic province, which forms a large arcuate band of alluvial sediments between the Alaska Range and the Yukon-Tanana Uplands. The Lowlands consist of vegetated floodplains and low benches cut by the Tanana River, and sloughs and oxbow lakes representing former channel positions of the Tanana or Chena Rivers. Soils in the Lowlands consist of interbedded alluvial sand and gravel covered by silty overbank deposits. The thickness of the alluvial sediments overlying bedrock in the project area is unknown.

Although the depth of alluvial sediments has not been well established in North Pole, it has been established to be as great as 400 feet to 500 feet in the Fairbanks area. We anticipate the thickness of alluvial deposits in North Pole would be similar to Fairbanks. Former slough channels are commonly filled with organic silt and peat deposits. These deposits are laterally discontinuous and vary in thickness. The portion of the Tanana Lowlands in which the site is located has not been glaciated.

The North Pole area is in a subarctic zone underlain by discontinuous permafrost. Permafrost is defined as ground that has remained at a temperature of 32 degrees Fahrenheit or less for two or more years. Although the depth of permafrost has not been well established in North Pole, the maximum depth of permafrost measured in the Fairbanks area is in excess of 250 feet. We anticipate the depth of permafrost in North Pole would be similar to Fairbanks. The thickness of the “active layer,” the portion of the ground at or near the surface that undergoes an annual freeze-thaw cycle, is largely dependent on the type of ground cover and snow depth. Seasonal frost-penetration commonly exceeds 10 feet beneath roads or parking areas kept free of snow during winter. In areas covered by thick mats of tundra or organic material, the thickness of the active zone is often 2 feet or less.

3.2 Seismicity

The North Pole area lies between two right-lateral shear systems: the Denali Fault System approximately 60 miles to 80 miles south of Fairbanks, and the Kaltag and Tintina Fault Systems, approximately 80 miles north. The shear along these systems is believed to be the result of crustal adjustments in the North American Plate due to convergence with the Pacific Plate along the Gulf of Alaska.

Within the past century, the area has been subjected to four large earthquakes. On July 22, 1937, a magnitude 7.3 (M_S) event occurred about 23 miles southeast of Fort Wainwright. This event, widely felt throughout central Alaska, produced extensive ground failures in the epicentral area (Page, and others, 1995). Two other earthquakes were an October 15, 1947, M_s 7.2 event about 41 miles south-southwest of Fairbanks, and an August 27, 1904, M_s 7.3 event about 17 miles southwest. A November 3, 2002, M_s 7.9 event on the Denali Fault, approximately 90 miles south of Fairbanks, was felt widely throughout central and southern Alaska, and resulted in minor liquefaction in the Fairbanks area. The peak horizontal ground acceleration of this event recorded on bedrock at the UAF campus was 0.09g.

3.3 Surface Conditions

The Lot 2 parcel is located east of H&H Road and historic photos and studies indicate previous development activity from farmland in the 1970s to initial site development for a refinery in the early 1980s. We evaluated aerial images, and past studies, and portions of the parcel have been cleared and fill materials were placed, but structures were not constructed and vegetation including birch, aspen, and spruce trees and scrub brush has regrown. We also note an abandoned slough that runs approximately from north to south in the middle of the lot.

The Lot F1A parcel is located west of H&H Road and is has been developed by previous owners. The site is generally flat, and includes structures, paving, and landscaped areas.

3.4 Subsurface Conditions

We observed similar conditions in some of our borings. We observed approximately 6 feet to 9.5 feet of silty, frost susceptible soils overlying alluvial sands and gravels to the depths explored. In Boring 17-02, we observed gravel with silt from approximately 2 feet bgs to 4.5 feet bgs that we believe is imported fill material.

We observed groundwater at depths ranging of approximately 3.5 feet bgs to 12 feet bgs at the time of drilling. We did not observe permafrost during exploration; a layer of remnant seasonal frost was observed from approximately 2 feet bgs to 4.5 feet bgs at the time of drilling.

4.0 EARTHQUAKE HAZARDS ANALYSIS

The project is in a seismic area where major earthquakes can and have occurred. Earthquake-induced geologic hazards that may affect a site include ground-surface fault rupture, and liquefaction and associated effects (e.g., loss of shear strength, bearing-capacity failures, loss of lateral support, ground oscillation, and lateral spreading). An associated effect of earthquake shaking is densification of the soils and potential ground settlement. Due to the presence of relatively loose soils and a shallow water table, the primary seismic hazard at the site is liquefaction. In borings drilled for the project, several samples from below the water table had uncorrected penetration resistance values (blow counts) of less than 20; some had blow counts of less than 10.

It has been our experience that soils in the Fairbanks area with blow counts as low as these are susceptible to liquefaction and dynamically induced densification if subjected to earthquake ground motions implied by the 2015 IBC. Densification of granular soils above and below the water table during earthquake shaking could result in significant ground settlement at the site. Associated effects of liquefaction may include a loss of soil shear strength, potential bearing-capacity failures, and lateral spreading. Our preliminary analysis of earthquake ground motions and earthquake-induced geologic hazards that may affect the site are described below.

4.1 Earthquake Ground Motion

Structural design performed in seismic regions for essential facilities generally requires a site-specific seismic analysis. For this concept phase study, we based our analyses on published seismic parameters. A site specific seismic analysis is being conducted for this project based on 150-foot-deep shear wave velocity testing conducted for the GVEA power plant, and will be presented as part of our final studies.

We developed seismic ground motions for the liquefaction analyses in general accordance with the 2015 NEHRP Provisions. The 5 percent damped design spectral response acceleration is defined as two-thirds of the site-adjusted maximum considered earthquake (MCE). The MCE was determined using maps for Site Class B published by the U.S. Geological Survey for ground motions with a two percent chance of occurrence in 50 years. We adjusted these values assuming Site Class D conditions at the site; sample penetration resistance values from our

explorations suggest that Site Class D soil conditions prevail at the site without regard for liquefaction. The mapped MCE geometric mean peak ground acceleration (PGA_M) was derived using 2010 ASCE 7 (with 2013 errata).

The following table summarizes earthquake ground motion parameters for this site.

Description	Parameter	Value
Site Class		D
Mapped spectral accelerations for 0.2 seconds (Site Class B, 5% damping)	S_s	0.99g
Mapped spectral accelerations for 1 second (Site Class B, 5% damping)	S_1	0.38g
S_s adjusted for site class	S_{MS}	1.09g
S_1 adjusted for site class	S_{M1}	0.73g
Design spectral response acceleration at short periods	S_{DS}	0.73g
Design spectral response acceleration at 1-second period	S_{D1}	0.49g
Peak ground acceleration	PGA_M	0.48g

4.2 Geologic Hazard Analyses

Earthquake-induced geologic hazards that we reviewed include landsliding, fault rupture, and liquefaction and its associated effects (e.g., loss of shear strength, bearing capacity failures, loss of lateral support, ground oscillation, lateral spreading, and settlement). In our opinion, due to the flat topography at the site, the risk of landsliding is low.

Seismicity in the Fairbanks-North Pole area has historically been concentrated in clusters or bands with a northeast-southwest trend that indicates active faulting, although no faults with Holocene displacement have been recognized in the area. An assessment of geologic maps reveals no conclusive evidence of faulting or fault-related geomorphic structures in the area; however, the absence of obvious fault-related geomorphic structures does not preclude the possibility of active faults in the area. In our opinion, the risk for surface-fault rupture at the project site is low.

4.3 Liquefaction Analyses

Liquefaction of loose, saturated, cohesionless soils occurs when excess pore pressures are generated as a result of earthquake shaking. Additionally, densification of the granular soils above and below the water table could occur when subject to earthquake shaking, resulting in

ground settlement at the site. The most widely used methods to evaluate liquefaction potential are empirical and based on correlations between Standard Penetration Test (SPT) resistance (N-value), PGA, and earthquake magnitude. We assumed a magnitude 7.3 for our analyses based on recent earthquakes that have occurred near the area and a peak ground acceleration (PGA_M) of 0.48g in the analyses.

We used three empirical procedures to evaluate liquefaction potential at this site:

- Youd and others (2001)
- Cetin and others (2004)
- Idriss and Boulanger (2014)

In these procedures, the N-value (blow count) is correlated to the liquefaction resistance of the soil (expressed as cyclic resistance ratio). The soil resistance is compared to the earthquake-induced loading (expressed as cyclic stress ratio), and a corresponding factor of safety (FS) against liquefaction is calculated.

In accordance with Section C11.8.3 in ASCE 07, we considered the soil to be potentially liquefiable if the calculated factor of safety is less than or equal to 1. The primary effect of liquefaction at the site is a reduction in the soil shear strength, settlement, and a reduction in bearing capacity.

We used the relationships by Tokimatsu and Seed (1987) and Ishihara and Yoshimine (1992), relating earthquake ground motion and penetration resistance with volumetric strain, to estimate the potential for free-field ground settlement in the borings we considered in the liquefaction analyses.

Using these relationships, in conjunction with the three procedures used to evaluate liquefaction potential in the borings we advanced at the site, we estimate 6 to 8 inches or more of free-field settlement could occur at the ground surface. In our opinion, the ground settlement may not occur uniformly over the project area and could be differential across the site.

4.4 Lateral Spreading

Liquefaction in gently sloping ground or ground adjacent to a free face can result in permanent lateral ground displacement in a phenomenon known as lateral spreading. Lateral spreading ground movement can occur toward a free face during or after seismic shaking in saturated, loose to medium dense, granular soil. Because the proposed structure is more than several hundred

feet from the nearest body of water, we believe the risk of lateral spreading for the project site is low.

5.0 DISCUSSION

We observed silty frost susceptible soils overlying alluvial sands and gravels to the depths explored. These silty soils are potentially compressible and frost-susceptible, and may contain organic slough deposits. Site development for structures will require replacing these soils down to relatively clean sands and gravels to improve bearing conditions and reduce the potential for consolidation- related settlement.

Our analyses show potential for widespread liquefaction in the soil mass below the groundwater table during the design earthquake. As a result, 6 inches to 8 inches or more of total and differential ground settlement along with reduction in soil strength could occur. We understand the project is an essential facility and ground improvement will be required to mitigate the liquefaction hazards. Soil improvement has two objectives: 1) to reduce potential dynamic settlement; and 2) improve soil shear strength during a seismic event and reduce the potential for a bearing-capacity failure during liquefaction.

5.1 Ground Improvement

Our approach to ground improvement is to densify the soil sufficiently both above and below the water table to reduce settlement and increase residual soil strength during a design seismic event. The increased residual soil strength will reduce the potential for a punching-type bearing-capacity failure and liquefaction-induced settlement.

In our opinion, deep dynamic compaction (DDC) and vibro-compaction ground improvement are both appropriate techniques that could be used to densify and improve soil conditions at this site.

DDC produces low frequency vibrations that could exceed peak particle velocities of 0.75 inches per second at distances of 75 feet or more from the improvement area. Vibrocompaction produces higher frequency vibrations which may produce peak particle velocities of 0.75 inches per second, or more, up to 30 feet from the point of ground improvement. Vibrocompaction ground improvement can be 3 to 5 times more expensive than DDC. If existing structures and improvements are 100 feet to 150 feet or more from the proposed site(s), DDC may be an appropriate method of ground improvement.

The soil improvement we recommend considering has two components:1) excavating the surficial silty soils and replacing with a relatively thick section of compacted sand and gravel

(i.e., structural fill) beneath foundation systems; and 2) densifying the soils below the water table using DDC techniques.

DDC, as referred to in this report, is a ground-improvement technique whereby a large tamper/weight (usually 6 tons to 40 tons) is dropped from a specified height (usually 30 feet to 120 feet) to compact materials in-place. We believe ground improvement may be performed using DDC techniques, based on our successful experience with DDC on multiple projects in similar soil conditions.

DDC soil improvement has been used for several projects in Fairbanks, including the FTW373A Warm Storage Hangar on Fort Wainwright, Hangar 6 on Fort Wainwright, the Carlson Center, the Bureau of Land Management (BLM) building on University Avenue, the FTW357 GSAB Hangar, and the FTW348A AAC Hangar. Soil improvement using vibro-compaction was completed for the University of Fairbanks Combined Heat and Power Plant, the Fairbanks Memorial Hospital Surgery Addition, Bassett Hospital on Fort Wainwright and the Alaska Department of Fish and Game Sport Fish Hatchery in Fairbanks.

5.2 Ground Vibration Monitoring

Visual pre-and post-condition surveys and vibration monitoring during ground improvement is recommended. At a minimum, vibration monitoring and pre-and-post condition surveys are recommended for building structures and utilities within a 150-foot radius of the proposed ground improvement areas, if anticipated ground vibrations exceed 2 inches per second when the frequency is 40 Hz or greater, or 0.75 inches per second when the frequency is less than 40 Hz at structures of concern.

Our experience suggests the frequency of DDC-induced ground motions, generated by a 15-ton weight dropped 50 feet, ranged from 5 to 18 Hz, and were typically less than 10 Hz. Recorded vibrations were about 0.75 inches per second 55 feet from the source, 0.5 inches per second 75 feet from the source, and 0.2 inches per second 150 feet from the source. We anticipate similar vibration levels and frequency for DDC-induced ground motions for this project; however, vibrations are dependent on several factors including depth to groundwater, density of soils, and soil type. We recommend intermittently monitoring ground vibrations within 150 feet of the improvement area to assess frequency and vibration levels and verify thresholds are not exceeded outside the 150-foot radius.

6.0 GEOTECHNICAL CONSIDERATIONS FOR SITE DEVELOPMENT

The following key geotechnical site development and design considerations have been identified during this concept phase study.

- The proposed sites have a significant seismic liquefaction hazard; primarily loss of shear strength and settlement during design seismic events.

- Site preparation for all structures will require removal of surficial silty frost susceptible soils and replacement with compacted structural fills.

- Ground improvement will be required for all essential facilities. Ground improvement will include the entire structure footprint and extend out beyond the outside edge of all foundations a minimum of 25 feet. The depth of required improvement, based on the initial subsurface findings, is about 30 to 35 feet below grade.

- Considerations should be given to performing ground improvement for future planned structure sites as well as initial site development. Future developments near initial planned developments could require more costly ground improvement techniques.

- Site preparation and DDC ground improvement should be performed during periods of low groundwater to maximize the depth of ground improvement. Low groundwater typically occurs in the spring.

7.0 CLOSING

This geotechnical findings report was prepared for the exclusive use of PDC Engineers, Inc. and their representatives for the design of the GVEA Fuel Storage Facility in North Pole, Alaska. This report should not be used without our approval if any of the following occurs:

- Conditions change due to natural forces or human activity under, at, or adjacent to the site.
- Assumptions stated in this report have changed.
- Project details change or new information becomes available such that our conclusions and recommendations may be affected.
- If the site ownership or land use has changed.
- More than one year has passed since the date of this report.

If any of these occur, we should be retained to review the applicability of our recommendations.

Shannon & Wilson, Inc., has prepared the document *"Important Information About Your Geotechnical/Environmental Report"* in Appendix D to assist you and others in understanding the uses and limitations of our reports. Please read this document to learn how you can lower your risks for this project.

Geotechnical Findings:
SHANNON & WILSON, INC.

Stephen Adamczak, Jr. P.E.
Vice President



Image provided courtesy of Pictometry International 2012

0 200 400 600

Feet

LEGEND

- Approximate Boring Location
- Alternative 1 Tank Location
- Alternative 3 Tank Location
- Alternative 2 Tank Location

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

SITE PLAN AND APPROXIMATE BORING LOCATIONS

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC. GEOTECHNICAL AND ENVIRONMENTAL CONSULTANTS

Figure 1

APPENDIX A

SOIL BORING LOGS AND SOIL CLASSIFICATION

APPENDIX A

SOIL BORING LOGS AND SOIL CLASSIFICATION

TABLES

A-1 Summary of Frozen Soil Classification System

FIGURES

A-1 Soil Description and Log Key
A-2 Log of Boring 17-01
A-3 Log of Boring 17-02
A-4 Log of Boring 17-03
A-5 Log of Boring 17-04
A-6 Log of Boring 17-05

TABLE A-1
SUMMARY OF FROZEN SOIL CLASSIFICATION SYSTEM

Description			Designation
Segregated ice is not visible by eye	Friable, poorly bonded Material is easily broken up		Nf
	Well bonded – Soil particles strongly held together by ice	No excess ice	Nbn
		Excess ice	Nbe
Segregated ice is visible by eye (less than 1 inch thick)	Individual ice crystals or inclusions		Vx
	Ice coatings on soil particles		Vc
	Stratified or distinctly oriented ice formations		Vs
	Randomly or irregularly oriented ice formations		Vr
Ice greater than 1 inch thick	Ice with soil inclusions		ICE + soil type
	Ice without soil inclusions		ICE

Note:
Based on Linell, K.A. and C.W. Kaplar, 1966, Description and Classification of Frozen Soils, U.S. Army Cold Regions Research Engineering Laboratory, Technical Report 150, Hanover, N.H.

Shannon & Wilson, Inc. (S&W), uses a soil identification system modified from the Unified Soil Classification System (USCS). Elements of the USCS and other definitions are provided on this and the following pages. Soil descriptions are based on visual-manual procedures (ASTM D2488) and laboratory testing procedures (ASTM D2487), if performed.

S&W INORGANIC SOIL CONSTITUENT DEFINITIONS

CONSTITUENT[2]	FINE-GRAINED SOILS (50% or more fines)[1]	COARSE-GRAINED SOILS (less than 50% fines)[1]
Major	***Silt, Lean Clay, Elastic Silt,*** or ***Fat Clay***[3]	***Sand*** or ***Gravel***[4]
Modifying (Secondary) Precedes major constituent	30% or more coarse-grained: ***Sandy*** or ***Gravelly***[4]	More than 12% fine-grained: ***Silty*** or ***Clayey***[3]
Minor Follows major constituent	15% to 30% coarse-grained: ***with Sand*** or ***with Gravel***[4]	5% to 12% fine-grained: ***with Silt*** or ***with Clay***[3]
	30% or more total coarse-grained *and* lesser coarse-grained constituent is 15% or more: ***with Sand*** or ***with Gravel***[5]	15% or more of a second coarse-grained constituent: ***with Sand*** or ***with Gravel***[5]

[1]All percentages are by weight of total specimen passing a 3-inch sieve.
[2]The order of terms is: *Modifying Major with Minor*.
[3]Determined based on behavior.
[4]Determined based on which constituent comprises a larger percentage.
[5]Whichever is the lesser constituent.

MOISTURE CONTENT TERMS

Dry	Absence of moisture, dusty, dry to the touch
Moist	Damp but no visible water
Wet	Visible free water, from below water table

STANDARD PENETRATION TEST (SPT) SPECIFICATIONS

Hammer:	140 pounds with a 30-inch free fall. Rope on 6- to 10-inch-diam. cathead 2-1/4 rope turns, > 100 rpm NOTE: If automatic hammers are used, blow counts shown on boring logs should be adjusted to account for efficiency of hammer.
Sampler:	10 to 30 inches long Shoe I.D. = 1.375 inches Barrel I.D. = 1.5 inches Barrel O.D. = 2 inches
N-Value:	Sum blow counts for second and third 6-inch increments. Refusal: 50 blows for 6 inches or less; 10 blows for 0 inches.

NOTE: Penetration resistances (N-values) shown on boring logs are as recorded in the field and have not been corrected for hammer efficiency, overburden, or other factors.

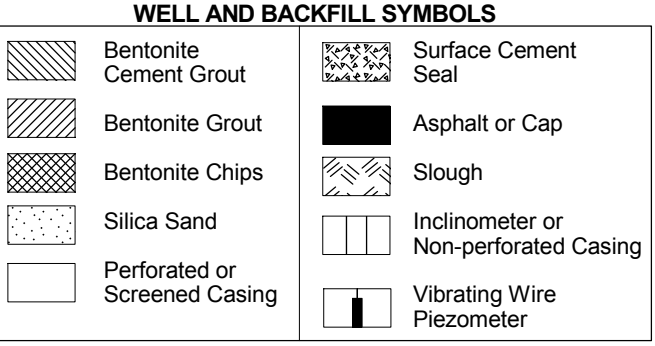
PARTICLE SIZE DEFINITIONS

DESCRIPTION	SIEVE NUMBER AND/OR APPROXIMATE SIZE
FINES	< #200 (0.075 mm = 0.003 in.)
SAND	
Fine	#200 to #40 (0.075 to 0.4 mm; 0.003 to 0.02 in.)
Medium	#40 to #10 (0.4 to 2 mm; 0.02 to 0.08 in.)
Coarse	#10 to #4 (2 to 4.75 mm; 0.08 to 0.187 in.)
GRAVEL	
Fine	#4 to 3/4 in. (4.75 to 19 mm; 0.187 to 0.75 in.)
Coarse	3/4 to 3 in. (19 to 76 mm)
COBBLES	3 to 12 in. (76 to 305 mm)
BOULDERS	> 12 in. (305 mm)

RELATIVE DENSITY / CONSISTENCY

COHESIONLESS SOILS		COHESIVE SOILS	
N, SPT, BLOWS/FT.	RELATIVE DENSITY	N, SPT, BLOWS/FT.	RELATIVE CONSISTENCY
< 4	Very loose	< 2	Very soft
4 - 10	Loose	2 - 4	Soft
10 - 30	Medium dense	4 - 8	Medium stiff
30 - 50	Dense	8 - 15	Stiff
> 50	Very dense	15 - 30	Very stiff
		> 30	Hard

WELL AND BACKFILL SYMBOLS



PERCENTAGES TERMS [1, 2]

Trace	< 5%
Few	5 to 10%
Little	15 to 25%
Some	30 to 45%
Mostly	50 to 100%

[1]Gravel, sand, and fines estimated by mass. Other constituents, such as organics, cobbles, and boulders, estimated by volume.

[2]Reprinted, with permission, from ASTM D2488 - 09a Standard Practice for Description and Identification of Soils (Visual-Manual Procedure), copyright ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA 19428. A copy of the complete standard may be obtained from ASTM International, www.astm.org.

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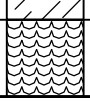
SOIL DESCRIPTION AND LOG KEY

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FIG. A-1
Sheet 1 of 3

2013_BORING_CLASS1_31-1-20006-001.GPJ_SHAN_WIL.GDT 6/1/17

UNIFIED SOIL CLASSIFICATION SYSTEM (USCS) (Modified From USACE Tech Memo 3-357, ASTM D2487, and ASTM D2488)					
MAJOR DIVISIONS			**GROUP/GRAPHIC SYMBOL**		**TYPICAL IDENTIFICATIONS**
COARSE-GRAINED SOILS *(more than 50% retained on No. 200 sieve)*	Gravels *(more than 50% of coarse fraction retained on No. 4 sieve)*	Gravel *(less than 5% fines)*	GW		Well-Graded Gravel; Well-Graded Gravel with Sand
			GP		Poorly Graded Gravel; Poorly Graded Gravel with Sand
		Silty or Clayey Gravel *(more than 12% fines)*	GM		Silty Gravel; Silty Gravel with Sand
			GC		Clayey Gravel; Clayey Gravel with Sand
	Sands *(50% or more of coarse fraction passes the No. 4 sieve)*	Sand *(less than 5% fines)*	SW		Well-Graded Sand; Well-Graded Sand with Gravel
			SP		Poorly Graded Sand; Poorly Graded Sand with Gravel
		Silty or Clayey Sand *(more than 12% fines)*	SM		Silty Sand; Silty Sand with Gravel
			SC		Clayey Sand; Clayey Sand with Gravel
FINE-GRAINED SOILS *(50% or more passes the No. 200 sieve)*	Silts and Clays *(liquid limit less than 50)*	Inorganic	ML		Silt; Silt with Sand or Gravel; Sandy or Gravelly Silt
			CL		Lean Clay; Lean Clay with Sand or Gravel; Sandy or Gravelly Lean Clay
		Organic	OL		Organic Silt or Clay; Organic Silt or Clay with Sand or Gravel; Sandy or Gravelly Organic Silt or Clay
	Silts and Clays *(liquid limit 50 or more)*	Inorganic	MH		Elastic Silt; Elastic Silt with Sand or Gravel; Sandy or Gravelly Elastic Silt
			CH		Fat Clay; Fat Clay with Sand or Gravel; Sandy or Gravelly Fat Clay
		Organic	OH		Organic Silt or Clay; Organic Silt or Clay with Sand or Gravel; Sandy or Gravelly Organic Silt or Clay
HIGHLY-ORGANIC SOILS	Primarily organic matter, dark in color, and organic odor		PT		Peat or other highly organic soils (see ASTM D4427)

NOTE: No. 4 size = 4.75 mm = 0.187 in.; No. 200 size = 0.075 mm = 0.003 in.

NOTES

1. Dual symbols *(symbols separated by a hyphen, i.e., SP-SM, Sand with Silt)* are used for soils with between 5% and 12% fines or when the liquid limit and plasticity index values plot in the CL-ML area of the plasticity chart. Graphics shown on the logs for these soil types are a combination of the two graphic symbols (e.g., SP and SM).

2. Borderline symbols *(symbols separated by a slash, i.e., CL/ML, Lean Clay to Silt; SP-SM/SM, Sand with Silt to Silty Sand)* indicate that the soil properties are close to the defining boundary between two groups.

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SOIL DESCRIPTION AND LOG KEY

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FIG. A-1
Sheet 2 of 3

2013_BORING_CLASS2_31-1-20006-001.GPJ_SHAN_WIL.GDT 6/1/17

GRADATION TERMS

Poorly Graded	Narrow range of grain sizes present or, within the range of grain sizes present, one or more sizes are missing (Gap Graded). Meets criteria in ASTM D2487, if tested.
Well-Graded	Full range and even distribution of grain sizes present. Meets criteria in ASTM D2487, if tested.

CEMENTATION TERMS[1]

Weak	Crumbles or breaks with handling or slight finger pressure.
Moderate	Crumbles or breaks with considerable finger pressure.
Strong	Will not crumble or break with finger pressure.

PLASTICITY[2]

DESCRIPTION	VISUAL-MANUAL CRITERIA	APPROX. PLASITICITY INDEX RANGE
Nonplastic	A 1/8-in. thread cannot be rolled at any water content.	< 4
Low	A thread can barely be rolled and a lump cannot be formed when drier than the plastic limit.	4 to 10
Medium	A thread is easy to roll and not much time is required to reach the plastic limit. The thread cannot be rerolled after reaching the plastic limit. A lump crumbles when drier than the plastic limit.	10 to 20
High	It takes considerable time rolling and kneading to reach the plastic limit. A thread can be rerolled several times after reaching the plastic limit. A lump can be formed without crumbling when drier than the plastic limit.	> 20

ADDITIONAL TERMS

Mottled	Irregular patches of different colors.
Bioturbated	Soil disturbance or mixing by plants or animals.
Diamict	Nonsorted sediment; sand and gravel in silt and/or clay matrix.
Cuttings	Material brought to surface by drilling.
Slough	Material that caved from sides of borehole.
Sheared	Disturbed texture, mix of strengths.

PARTICLE ANGULARITY AND SHAPE TERMS[1]

Angular	Sharp edges and unpolished planar surfaces.
Subangular	Similar to angular, but with rounded edges.
Subrounded	Nearly planar sides with well-rounded edges.
Rounded	Smoothly curved sides with no edges.
Flat	Width/thickness ratio > 3.
Elongated	Length/width ratio > 3.

ACRONYMS AND ABBREVIATIONS

ATD	At Time of Drilling
Diam.	Diameter
Elev.	Elevation
ft.	Feet
FeO	Iron Oxide
gal.	Gallons
Horiz.	Horizontal
HSA	Hollow Stem Auger
I.D.	Inside Diameter
in.	Inches
lbs.	Pounds
MgO	Magnesium Oxide
mm	Millimeter
MnO	Manganese Oxide
NA	Not Applicable or Not Available
NP	Nonplastic
O.D.	Outside Diameter
OW	Observation Well
pcf	Pounds per Cubic Foot
PID	Photo-Ionization Detector
PMT	Pressuremeter Test
ppm	Parts per Million
psi	Pounds per Square Inch
PVC	Polyvinyl Chloride
rpm	Rotations per Minute
SPT	Standard Penetration Test
USCS	Unified Soil Classification System
q_u	Unconfined Compressive Strength
VWP	Vibrating Wire Piezometer
Vert.	Vertical
WOH	Weight of Hammer
WOR	Weight of Rods
Wt.	Weight

STRUCTURE TERMS[1]

Interbedded	Alternating layers of varying material or color with layers at least 1/4-inch thick; singular: bed.
Laminated	Alternating layers of varying material or color with layers less than 1/4-inch thick; singular: lamination.
Fissured	Breaks along definite planes or fractures with little resistance.
Slickensided	Fracture planes appear polished or glossy; sometimes striated.
Blocky	Cohesive soil that can be broken down into small angular lumps that resist further breakdown.
Lensed	Inclusion of small pockets of different soils, such as small lenses of sand scattered through a mass of clay.
Homogeneous	Same color and appearance throughout.

[1]Reprinted, with permission, from ASTM D2488 - 09a Standard Practice for Description and Identification of Soils (Visual-Manual Procedure), copyright ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA 19428. A copy of the complete standard may be obtained from ASTM International, www.astm.org.

[2]Adapted, with permission, from ASTM D2488 - 09a Standard Practice for Description and Identification of Soils (Visual-Manual Procedure), copyright ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA 19428. A copy of the complete standard may be obtained from ASTM International, www.astm.org.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

SOIL DESCRIPTION AND LOG KEY

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

FIG. A-1
Sheet 3 of 3

2013_BORING_CLASS3_31-1-20006-001.GPJ_SHAN_WIL.GDT 6/1/17

Total Depth:	61.5 ft.	Northing:		Drilling Method:	Hollow Stem Auger	Hole Diam.:	8 in.
Top Elevation:	~	Easting:		Drilling Company:	Homestead Drilling	Rod Diam.:	
Vert. Datum:	NAD 83, Zone 3	Station:		Drill Rig Equipment:	B61 Tracked Rig	Hammer Type:	Automatic
Horiz. Datum:	NAD 83, Zone 3	Offset:		Other Comments:			

SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

Gray-brown, *Poorly Graded Gravel with Sand (GP)*; moist.

2.0

Loose, gray-brown, *Sandy Silt (ML)*; moist; trace organics.

8.5

Loose, gray-brown, *Silty Sand (SM)*; moist; trace organics.

9.5

Loose to medium-dense, gray-brown, *Poorly Graded Gravel with Silt and Sand (GP-GM) to Well-Graded Gravel with Sand (GW) to Poorly Graded Gravel with Sand (GP)*; moist to 12.0 feet, wet below 12.0 feet; fractured gravel up to 3 inches present in some samples.

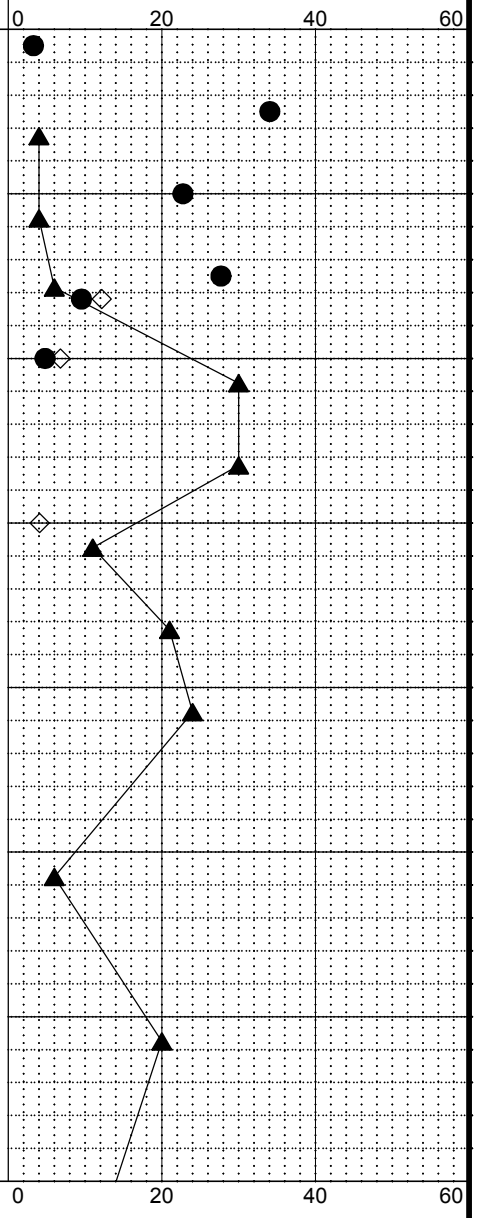
CONTINUED NEXT SHEET

Depth, ft.	PID, ppm	Samples
	0.6	1
	0.3	2
	0.6	3
	0.4	4a
	0.6	4b
	0.6	5
		6
		7
		8
		9
		10
		11

Ground Water Depth, ft.: During Drilling ▽

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: 300 lbs / 30 inches



LEGEND

* Sample Not Recovered

▽ Ground Water Level ATD

Grab Sample

3" O.D. Split Spoon Sample

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-01

June 2017 31-1-20006-001R1

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Geotechnical and Environmental Consultants

FIG. A-2
Sheet 1 of 2

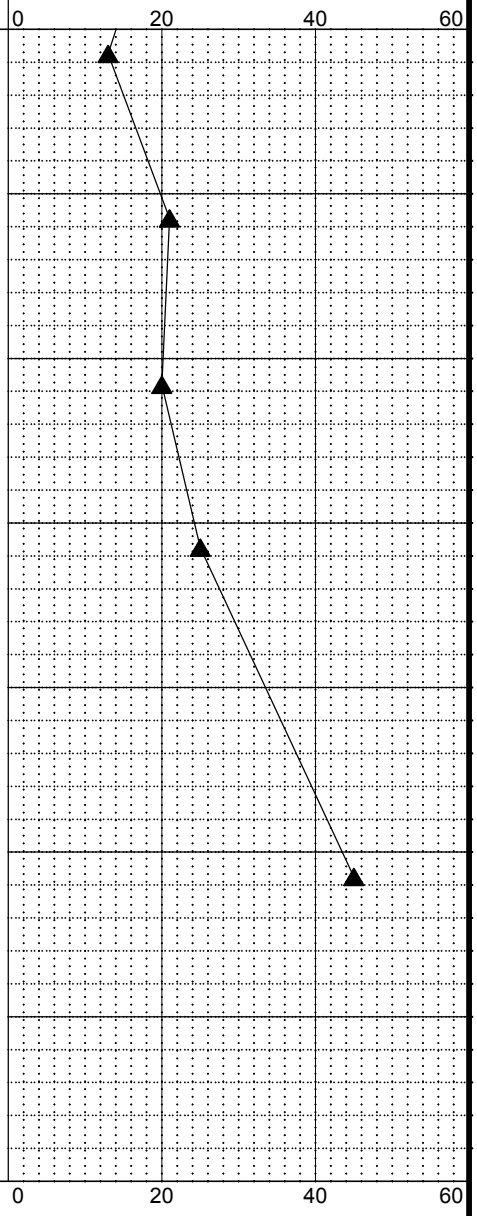
MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/4/17 Rev: IAS Typ: Dym Pxg

Total Depth:	*61.5 ft.*	Northing:		Drilling Method:	*Hollow Stem Auger*	Hole Diam.:	*8 in.*
Top Elevation:	*~*	Easting:		Drilling Company:	*Homestead Drilling*	Rod Diam.:	
Vert. Datum:	*NAD 83, Zone 3*	Station:		Drill Rig Equipment:	*B61 Tracked Rig*	Hammer Type:	*Automatic*
Horiz. Datum:	*NAD 83, Zone 3*	Offset:		Other Comments:			

SOIL DESCRIPTION	Depth, ft.	Symbol	PID, ppm	Samples	Ground Water	Depth, ft.
Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.						
				12		
				13		
				14		
				15		
				16		
BOTTOM OF BORING BORING COMPLETED 5/15/2017	61.5					

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: *300 lbs / 30 inches*



LEGEND

* Sample Not Recovered

Grab Sample

3" O.D. Split Spoon Sample

▽ Ground Water Level ATD

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-01

June 2017 31-1-20006-001R1

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FIG. A-2
Sheet 2 of 2

MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/27/17 Rev: IAS Typ: Dym

Total Depth:	61.5 ft.	Northing:		Drilling Method:	Hollow Stem Auger	Hole Diam.:	8 in.
Top Elevation:	~	Easting:		Drilling Company:	Homestead Drilling	Rod Diam.:	
Vert. Datum:	NAD 83, Zone 3	Station:		Drill Rig Equipment:	B61 Tracked Rig	Hammer Type:	Automatic
Horiz. Datum:	NAD 83, Zone 3	Offset:		Other Comments:			

SOIL DESCRIPTION	Depth, ft.
Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.	
Brown, *Poorly Graded Sand with Silt (SP-SM)*; moist; trace gravel.	
Gray-brown, *Well-Graded Gravel with Silt and Sand (GW-GM)*; wet to 3.5 feet; frozen, Nbn from 3.5 feet to 4.5 feet.	2.0
Loose to medium-dense, gray-brown, *Poorly Graded Gravel with Sand (GP)*; wet; trace fines.	4.5
Loose to medium-dense, gray-brown, *Poorly Graded Sand (SP)*; wet; trace to few gravel, trace fines.	12.0
Loose to dense, gray-brown, *Poorly Graded Gravel with Sand (GP)*; wet; gravel up to 3 inches present in sample 12; trace fines.	17.0

Frozen =

Symbol

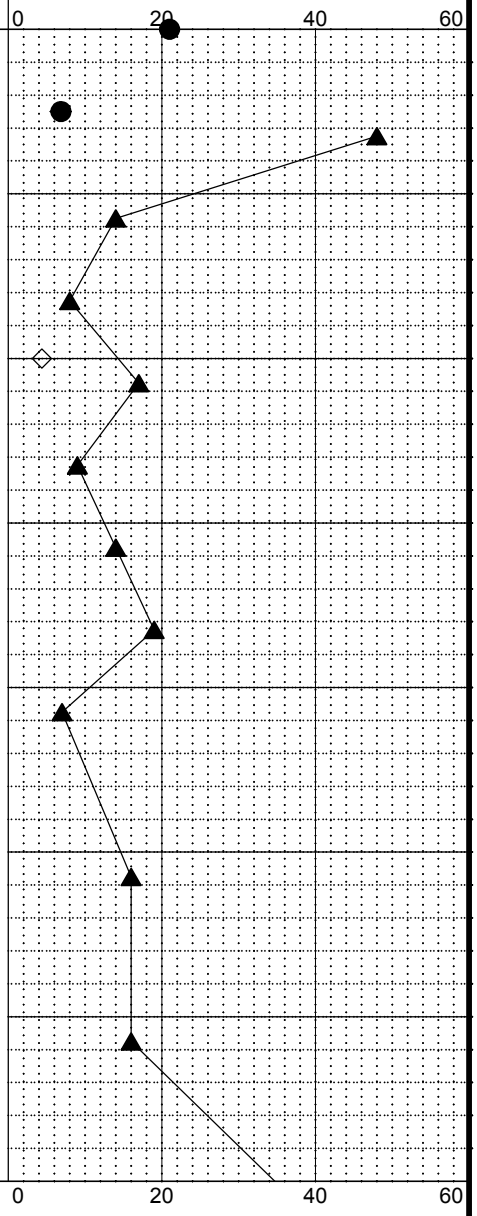
PID, ppm: 0.2, 0.1, 0.3

Samples: 1 (G), 2, 3, 4, 5, 6, 7, 8, 9, 10, 11

Ground Water Depth, ft.: During Drilling ▽

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: *300 lbs / 30 inches*



CONTINUED NEXT SHEET

LEGEND

* Sample Not Recovered

▽ Ground Water Level ATD

Grab Sample

3" O.D. Split Spoon Sample

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-02

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

FIG. A-3
Sheet 1 of 2

MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/27/17 Rev: IAS Typ: Dym

Total Depth:	*61.5 ft.*	Northing:		Drilling Method:	*Hollow Stem Auger*	Hole Diam.:	*8 in.*
Top Elevation:	*~*	Easting:		Drilling Company:	*Homestead Drilling*	Rod Diam.:	
Vert. Datum:	*NAD 83, Zone 3*	Station:		Drill Rig Equipment:	*B61 Tracked Rig*	Hammer Type:	*Automatic*
Horiz. Datum:	*NAD 83, Zone 3*	Offset:		Other Comments:			

SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

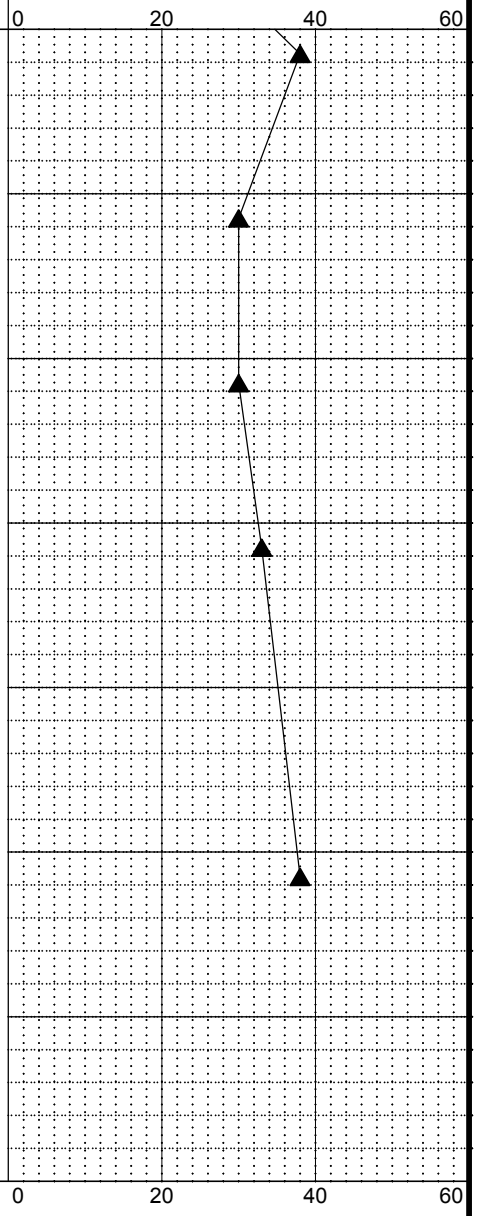
Frozen = ■

Depth, ft.	Symbol	PID, ppm	Samples	Ground Water	Depth, ft.
61.5			12, 13, 14, 15, 16		

BOTTOM OF BORING
BORING COMPLETED 5/16/2017

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: *300 lbs / 30 inches*



LEGEND

* Sample Not Recovered
Grab Sample
3" O.D. Split Spoon Sample
▽ Ground Water Level ATD

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-02

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
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FIG. A-3
Sheet 2 of 2

MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/27/17 Rev: IAS Typ: Dym

Total Depth:	61.5 ft.	Northing:		Drilling Method:	Hollow Stem Auger	Hole Diam.:	8 in.
Top Elevation:	~	Easting:		Drilling Company:	Homestead Drilling	Rod Diam.:	
Vert. Datum:	NAD 83, Zone 3	Station:		Drill Rig Equipment:	B61 Tracked Rig	Hammer Type:	Automatic
Horiz. Datum:	NAD 83, Zone 3	Offset:		Other Comments:			

SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

Frozen =

Gray-brown, *Poorly Graded Sand with Silt (SP-SM)*; moist to 2.0 feet; frozen, Nbn to Nf from 2.0 feet to 4.5 feet.

4.5

Loose, gray-brown, *Poorly Graded Sand with Silt (SP-SM)*; moist.

7.0

Loose to dense, gray-brown, *Well-Graded Gravel with Sand (GW) to Poorly Graded Gravel with Sand (GP)*; moist to 7.0 feet, wet below 7.0 feet; fractured gravel up to 3 inches present in some samples; trace fines.

CONTINUED NEXT SHEET

Depth, ft. | Symbol | PID, ppm | Samples | Ground Water Depth, ft.

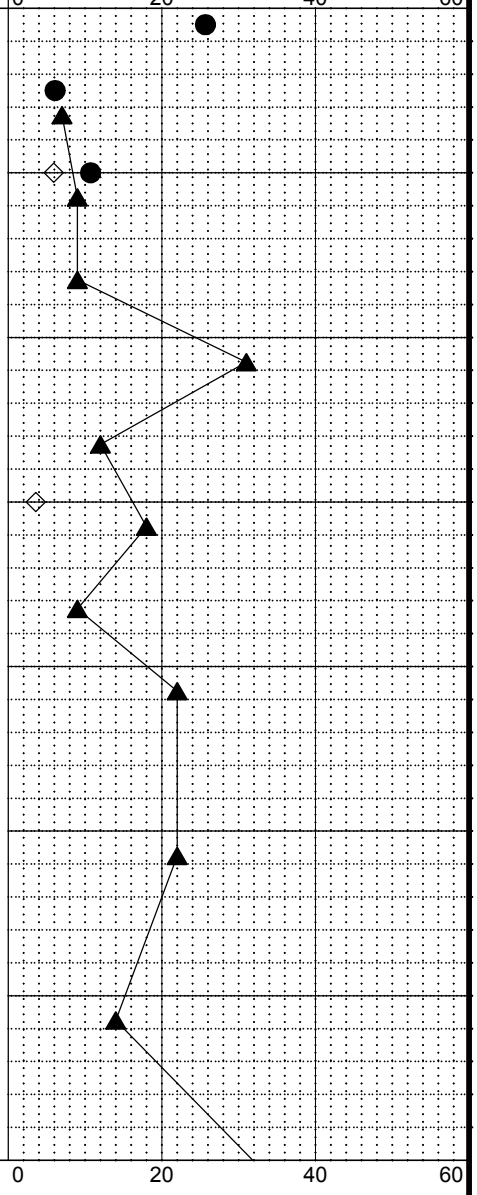
PID, ppm: 0.3, 0.6, 0.2, 0.4

Samples: 1 (G), 2, 3, 4, 5, 6, 7, 8, 9, 10, 11

During Drilling ▽

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: 300 lbs / 30 inches



LEGEND

* Sample Not Recovered

Grab Sample

3" O.D. Split Spoon Sample

▽ Ground Water Level ATD

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-03

June 2017 31-1-20006-001R1

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FIG. A-4
Sheet 1 of 2

MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/4/17 Rev: IAS Typ: Dym

Total Depth:	*61.5 ft.*	Northing:		Drilling Method:	*Hollow Stem Auger*	Hole Diam.:	*8 in.*
Top Elevation:	*~*	Easting:		Drilling Company:	*Homestead Drilling*	Rod Diam.:	
Vert. Datum:	*NAD 83, Zone 3*	Station:		Drill Rig Equipment:	*B61 Tracked Rig*	Hammer Type:	*Automatic*
Horiz. Datum:	*NAD 83, Zone 3*	Offset:		Other Comments:			

SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

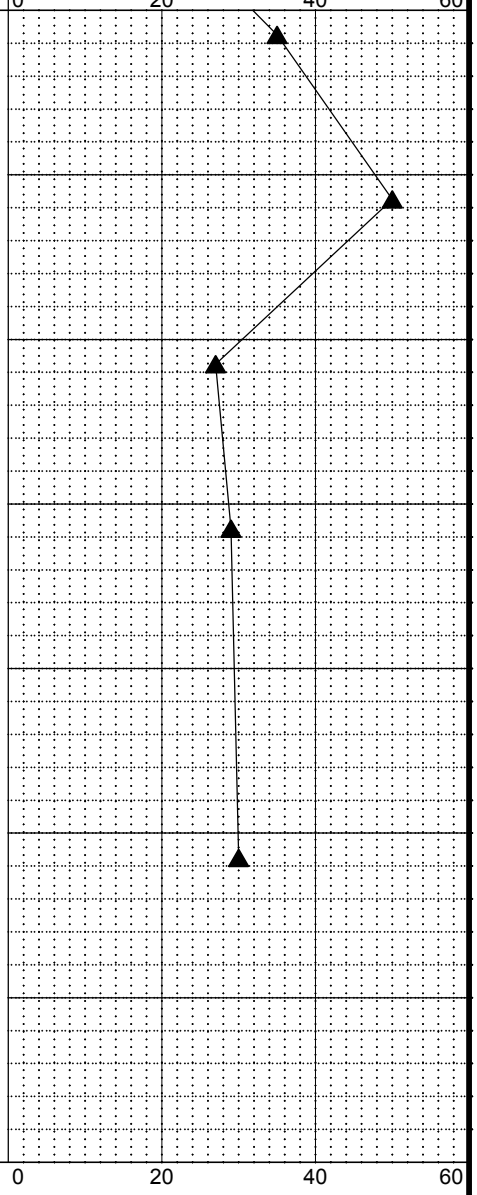
Frozen = ■

Depth, ft.	Symbol	PID, ppm	Samples	Ground Water	Depth, ft.
61.5			12, 13, 14, 15, 16		

BOTTOM OF BORING
BORING COMPLETED 5/17/2017

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: *300 lbs / 30 inches*



◇ % Fines (<0.075mm)
● % Water Content

LEGEND

* Sample Not Recovered
Grab Sample
3" O.D. Split Spoon Sample
Ground Water Level ATD

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-03

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

FIG. A-4
Sheet 2 of 2

MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/27/17 Rev: IAS Typ: Dym

Total Depth:	61.5 ft.	Northing:		Drilling Method:	Hollow Stem Auger	Hole Diam.:	8 in.
Top Elevation:	~	Easting:		Drilling Company:	Homestead Drilling	Rod Diam.:	
Vert. Datum:	NAD 83, Zone 3	Station:		Drill Rig Equipment:	B61 Tracked Rig	Hammer Type:	Automatic
Horiz. Datum:	NAD 83, Zone 3	Offset:		Other Comments:			

SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

Frozen =

Gray-brown, *Sandy Silt (ML)*; moist to 1.0 foot; frozen, Nbn from 1.0 foot to 2.5 feet; trace to few organics.

2.5

Loose, gray-brown, *Silty Sand (SM)*; moist.

6.0

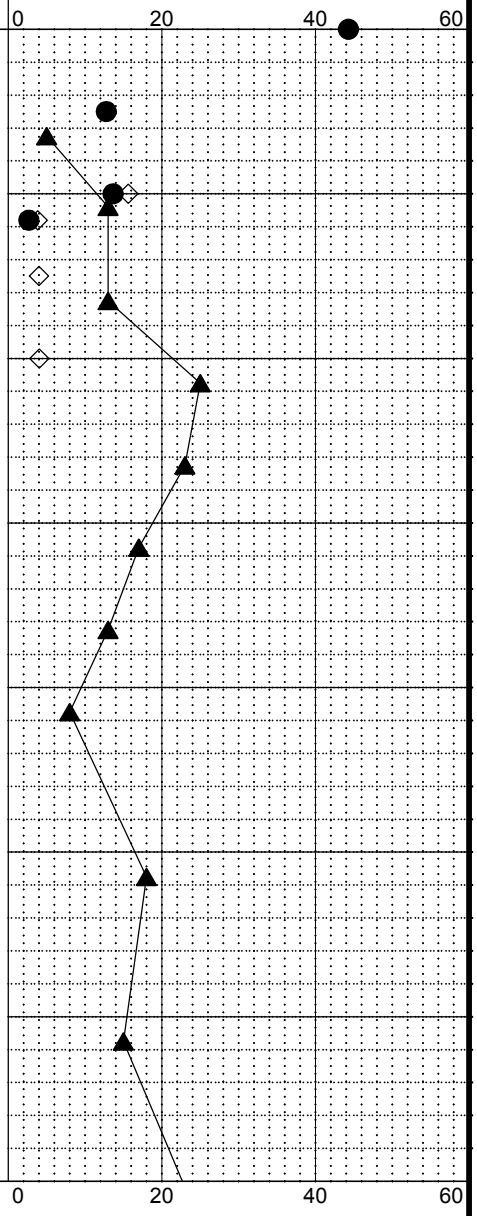
Loose to dense, gray-brown, *Poorly Graded Gravel with Sand (GP)*; moist to 7.0 feet, wet below 7.0 feet; gravel up to 3 inches present in many samples; trace fines.

CONTINUED NEXT SHEET

Depth, ft.	Symbol	PID, ppm	Samples	Ground Water Depth, ft.
		0.7	1 G	
		0.5	2	
		0.6	3a	
		0.7	3b	
		0.6	4	During Drilling ▽
			5	
			6	
			7	
			8	
			9	
			10	
			11	

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: 300 lbs / 30 inches



LEGEND

* Sample Not Recovered

G Grab Sample

3" O.D. Split Spoon Sample

▽ Ground Water Level ATD

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-04

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

FIG. A-5
Sheet 1 of 2

MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/4/17 Pxg Rev: IAS Typ: Dym

Total Depth:	*61.5 ft.*	Northing:		Drilling Method:	*Hollow Stem Auger*	Hole Diam.:	*8 in.*
Top Elevation:	*~*	Easting:		Drilling Company:	*Homestead Drilling*	Rod Diam.:	
Vert. Datum:	*NAD 83, Zone 3*	Station:		Drill Rig Equipment:	*B61 Tracked Rig*	Hammer Type:	*Automatic*
Horiz. Datum:	*NAD 83, Zone 3*	Offset:		Other Comments:			

SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

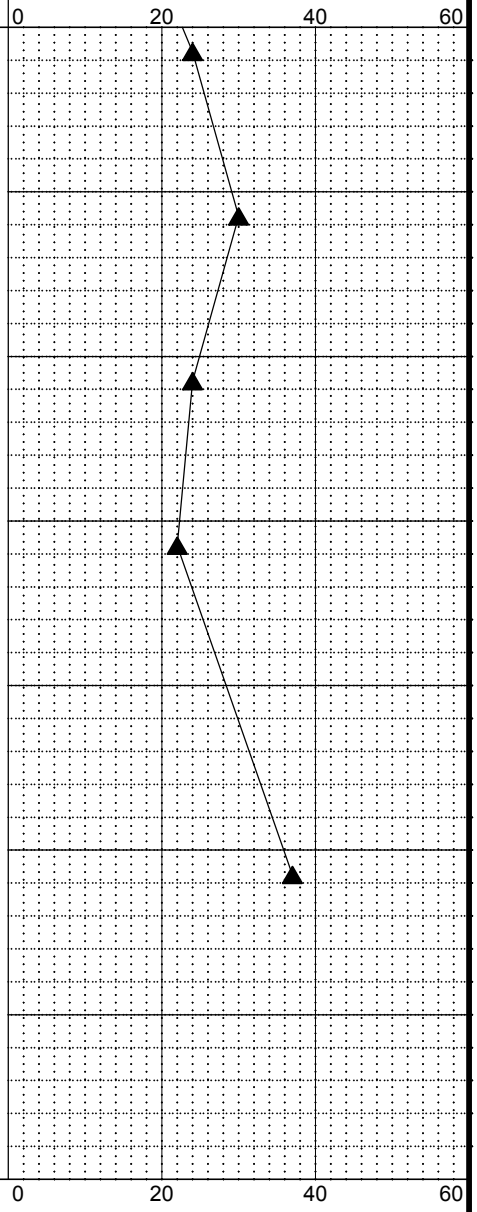
Frozen = ■

Depth, ft.	Symbol	PID, ppm	Samples	Ground Water Depth, ft.
61.5			12, 13, 14, 15, 16	

BOTTOM OF BORING
BORING COMPLETED 5/17/2017

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: *300 lbs / 30 inches*



LEGEND

* Sample Not Recovered
Grab Sample
3" O.D. Split Spoon Sample
▽ Ground Water Level ATD

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-04

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
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FIG. A-5
Sheet 2 of 2

MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/27/17 Rev: IAS Typ: Dym

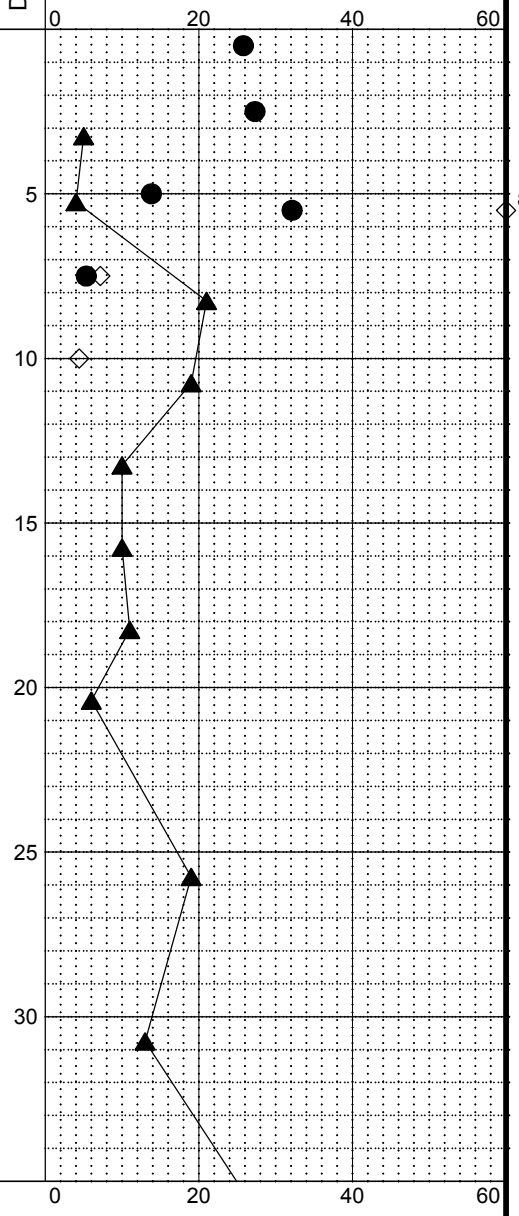
Total Depth:	61.5 ft.	Northing:		Drilling Method:	Hollow Stem Auger	Hole Diam.:	8 in.
Top Elevation:	~	Easting:		Drilling Company:	Homestead Drilling	Rod Diam.:	
Vert. Datum:	NAD 83, Zone 3	Station:		Drill Rig Equipment:	B61 Tracked Rig	Hammer Type:	Automatic
Horiz. Datum:	NAD 83, Zone 3	Offset:		Other Comments:			

SOIL DESCRIPTION	Depth, ft.	Symbol	PID, ppm	Samples
Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual. Frozen =				
Gray-brown, *Silt with Sand (ML)*; moist to 1 foot; frozen, Nbn from 1 foot to 2.5 feet; trace organics.			1.3	1 G
	2.5			
Loose, gray-brown to gray, *Silt with Sand (ML) to Silty Sand (SM)*; moist; trace organics to 4.5 feet.			0.7	2
			0.8	3a
			0.7	3b
	7.5			
Loose to medium-dense, gray-brown, *Poorly Graded Gravel with Silt and Sand (GP-GM) to Poorly Graded Gravel with Sand (GP)*; moist to 9.5 feet, wet below 9.5 feet.			1	4
			0.2	5
				6
				7
				8
	21.0			9a
				9b
Loose, gray-brown, *Poorly Graded Sand (SP)*; wet; trace fines.				
	23.0			
Medium-dense to dense, gray-brown, *Poorly Graded Gravel with Sand (GP)*; wet; coarse, subangular to subrounded gravel; trace fines.				10
				11

Ground Water Depth, ft. — During Drilling ▽

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: *300 lbs / 30 inches*



CONTINUED NEXT SHEET

LEGEND

* Sample Not Recovered
G Grab Sample
3" O.D. Split Spoon Sample
▽ Ground Water Level ATD

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-05

June 2017 31-1-20006-001R1

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FIG. A-6
Sheet 1 of 2

MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/4/17 Pxg Rev: IAS Typ: Dym

REV 3 - Approved for Submittal

Total Depth:	61.5 ft.	Northing:		Drilling Method:	Hollow Stem Auger	Hole Diam.:	8 in.
Top Elevation:	~	Easting:		Drilling Company:	Homestead Drilling	Rod Diam.:	
Vert. Datum:	NAD 83, Zone 3	Station:		Drill Rig Equipment:	B61 Tracked Rig	Hammer Type:	Automatic
Horiz. Datum:	NAD 83, Zone 3	Offset:		Other Comments:			

SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

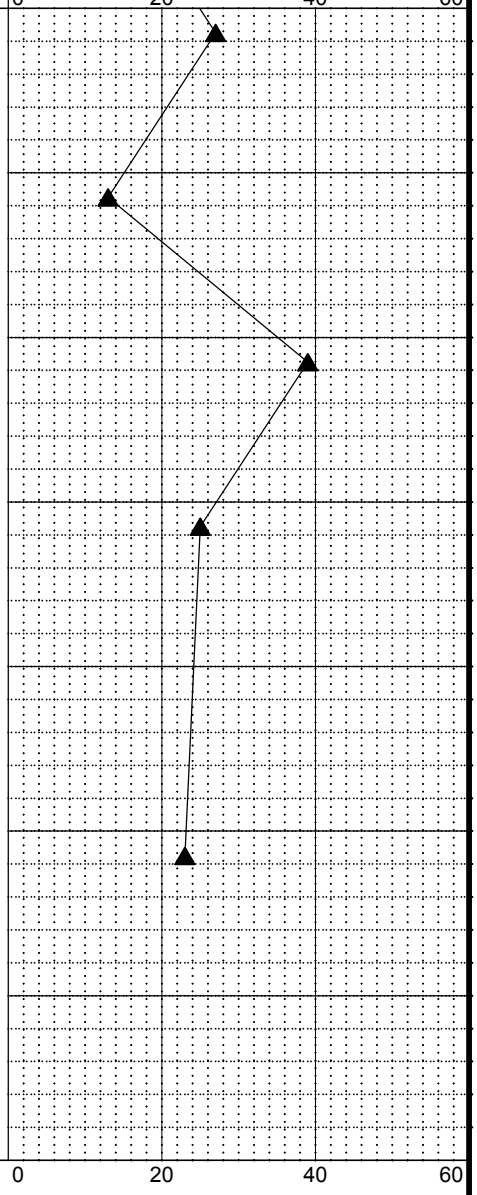
Frozen = ■

Depth, ft.	Symbol	PID, ppm	Samples	Ground Water Depth, ft.
61.5			12, 13, 14, 15, 16	

BOTTOM OF BORING
BORING COMPLETED 5/18/2017

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: 300 lbs / 30 inches



LEGEND

* Sample Not Recovered
Grab Sample
3" O.D. Split Spoon Sample
▽ Ground Water Level ATD

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-05

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SHANNON & WILSON, INC.
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FIG. A-6
Sheet 2 of 2

MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/27/17 Rev: IAS Typ: Dym

APPENDIX B

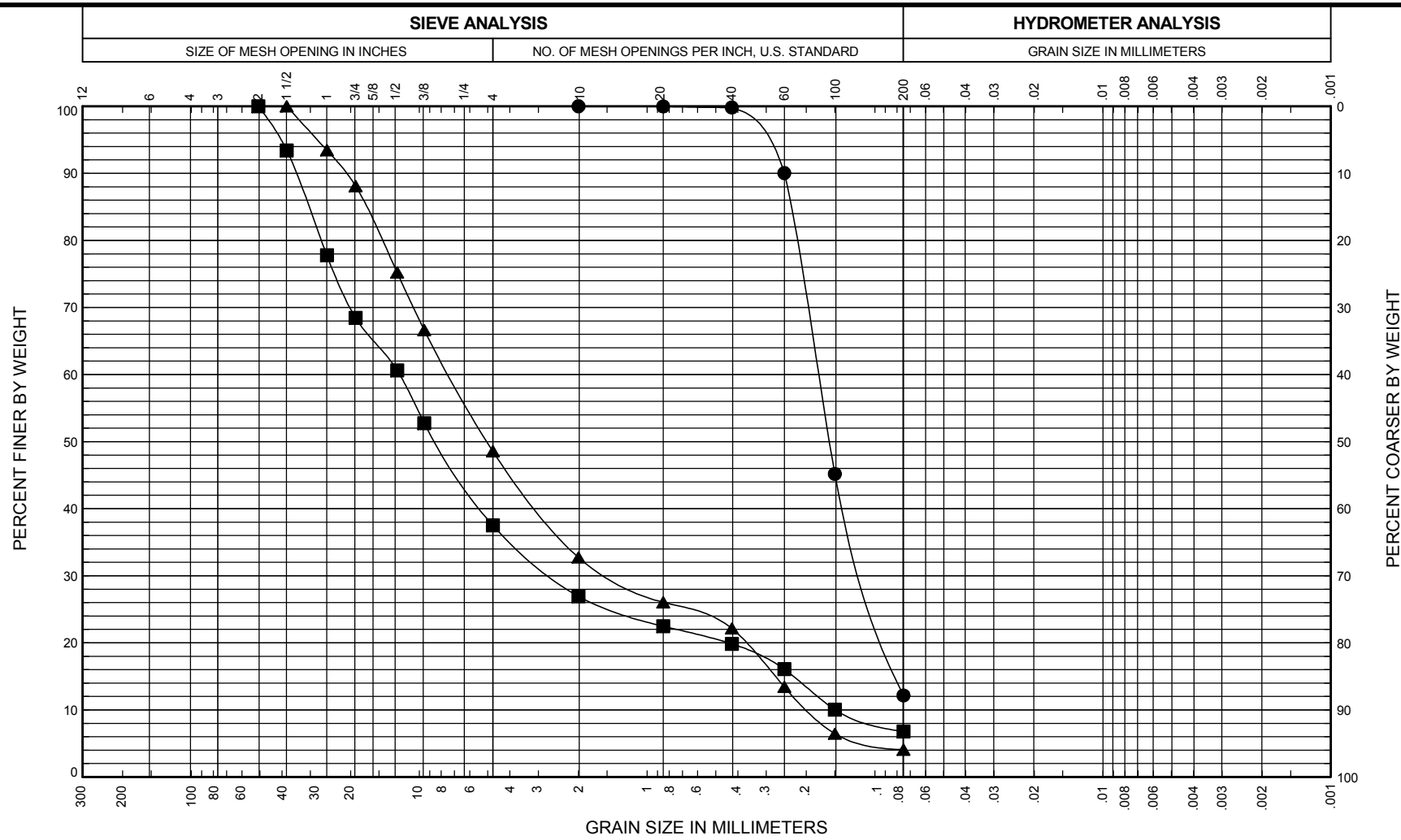
GRAIN SIZE DISTRIBUTIONS

APPENDIX B

GRAIN SIZE DISTRIBUTIONS

FIGURES

B-1 Grain Size Distribution; Boring 17-01
B-2 Grain Size Distribution; Boring 17-02
B-3 Grain Size Distribution; Boring 17-03
B-4 Grain Size Distribution; Boring 17-04
B-5 Grain Size Distribution; Boring 17-05



BORING AND SAMPLE NO.	DEPTH (feet)	U.S.C.S. SYMBOL	SOIL CLASSIFICATION	COBBLE %	GRAVEL %	SAND %	FINES %	NAT. W.C. %	TEST BY	REVIEW BY	ASTM STD
● 17-01, 4b	8.2	SM	Silty Sand			88	12.2	9.5	SLD	AMV	C136
■ 17-01, S-5*	10.0	GP-GM	Poorly Graded Gravel with Silt and Sand		62	31	6.8	4.8	ALW	AMV	C136
▲ 17-01, S-7*	15.0	GW	Well-Graded Gravel with Sand		51	44	4.1		ALW	AMV	C136

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

GRAIN SIZE DISTRIBUTION
BORING 17-01

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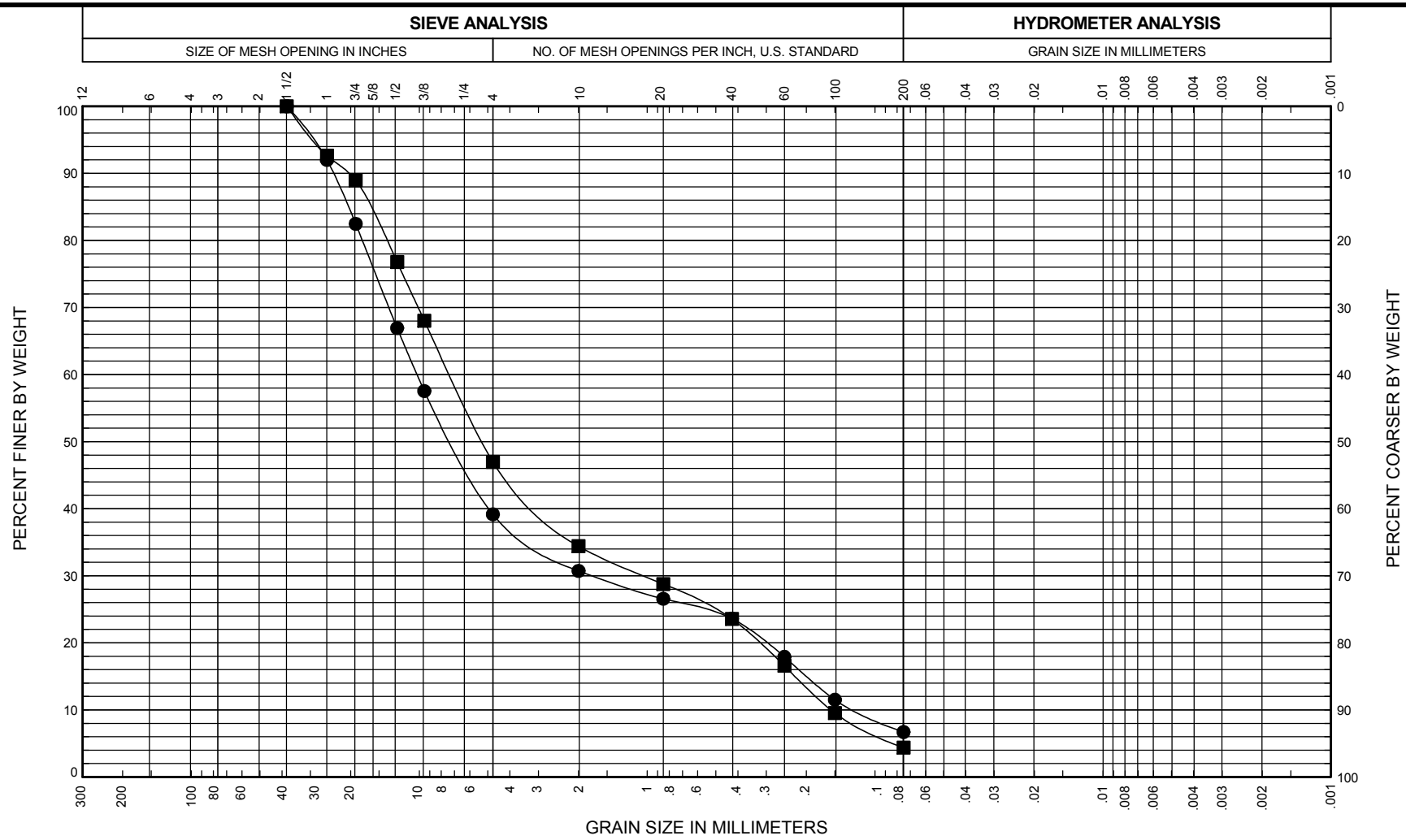
FIG. B-1
Sheet 1 of 1

FIG. B-1

** Sample specimen weight did not meet required minimum mass for ASTM test method.*

PDC Engineers, Inc.

AASHTO GSA MAIN 31-1-20006-001.GPJ SHAN WIL.GDT 6/1/17



BORING AND SAMPLE NO.	DEPTH (feet)	U.S.C.S. SYMBOL	SOIL CLASSIFICATION	COBBLE %	GRAVEL %	SAND %	FINES %	NAT. W.C. %	TEST BY	REVIEW BY	ASTM STD
● 17-02, S-2*	2.5	GW-GM	Well-Graded Gravel with Silt and Sand		61	32	6.7	6.9	EJB	AMV	C136
■ 17-02, S-5*	10.0	GP	Poorly Graded Gravel with Sand		53	43	4.4		EJB	AMV	C136

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

GRAIN SIZE DISTRIBUTION
BORING 17-02

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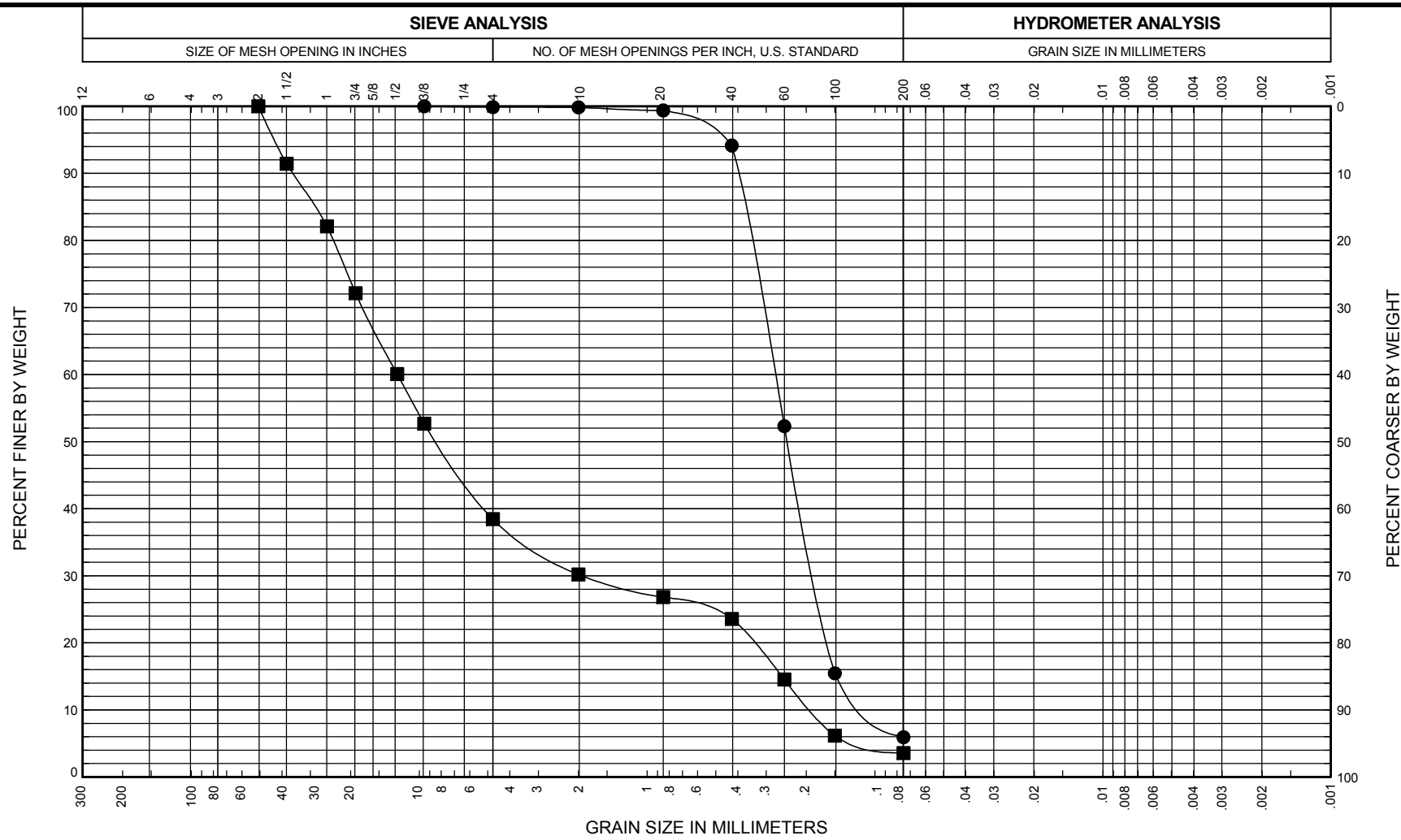
FIG. B-2
Sheet 1 of 1

FIG. B-2

** Sample specimen weight did not meet required minimum mass for ASTM test method.*

PDC Engineers, Inc.

AASHTO GSA MAIN 31-1-20006-001.GPJ SHAN WIL.GDT 6/1/17



BORING AND SAMPLE NO.	DEPTH (feet)	U.S.C.S. SYMBOL	SOIL CLASSIFICATION	COBBLE %	GRAVEL %	SAND %	FINES %	NAT. W.C. %	TEST BY	REVIEW BY	ASTM STD
● 17-03, S-3	5.0	SP-SM	Poorly Graded Sand with Silt		0	94	5.9	10.7	ALW	AMV	C136
■ 17-03, S-7*	15.0	GW	Well-Graded Gravel with Sand		62	35	3.6		ALW	AMV	C136

** Sample specimen weight did not meet required minimum mass for ASTM test method.*

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

GRAIN SIZE DISTRIBUTION
BORING 17-03

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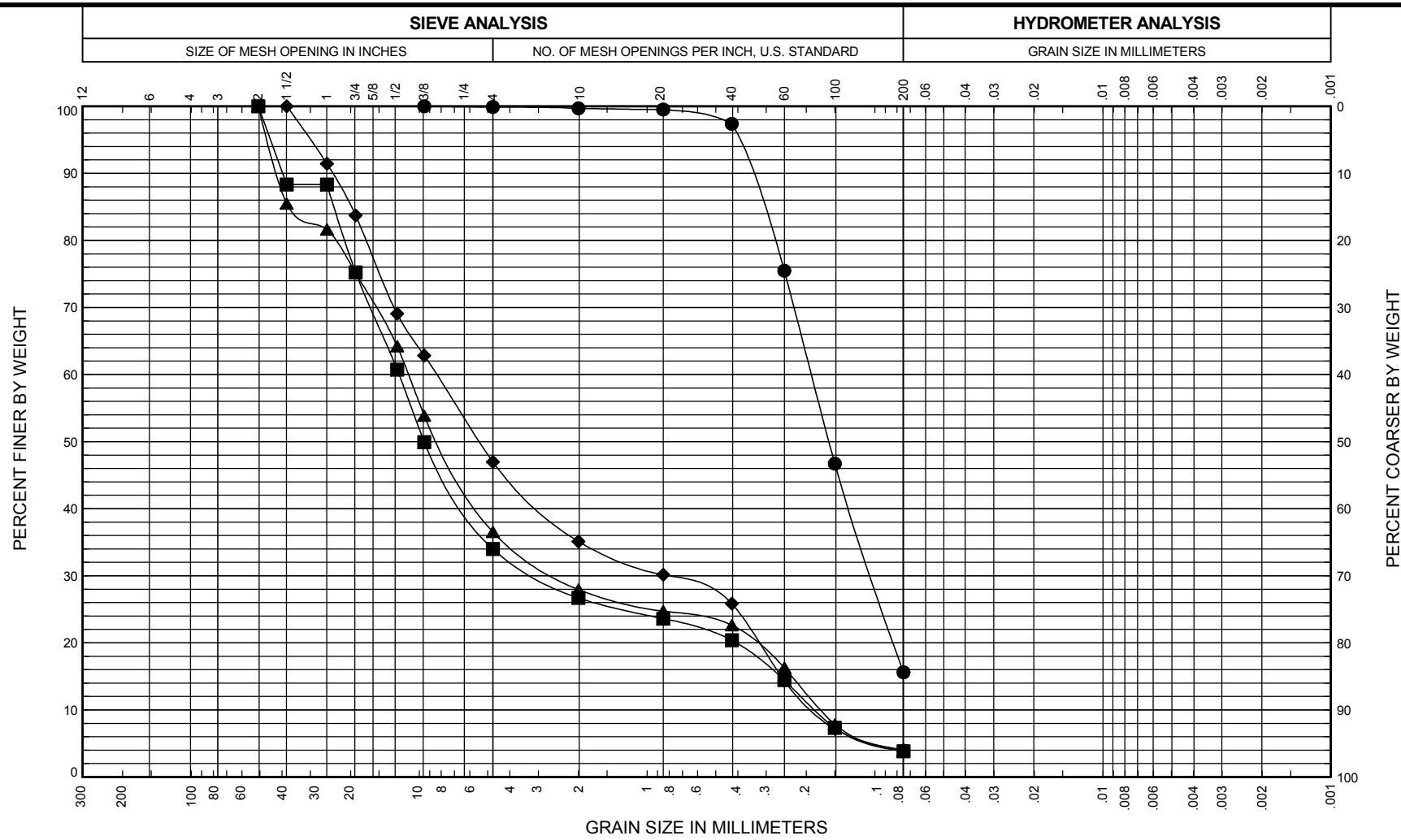
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FIG. B-3
Sheet 1 of 1

FIG. B-3

PDC Engineers, Inc.

AASHTO GSA MAIN 31-1-20006-001.GPJ SHAN WIL.GDT 6/1/17



BORING AND SAMPLE NO.	DEPTH (feet)	U.S.C.S. SYMBOL	SOIL CLASSIFICATION	COBBLE %	GRAVEL %	SAND %	FINES %	NAT. W.C. %	TEST BY	REVIEW BY	ASTM STD
● 17-04, 3a*	5.0	SM	Silty Sand		0	84	15.6	13.7	EJB	AMV	C136
■ 17-04, 3b*	5.8	GP	Poorly Graded Gravel with Sand		66	30	3.8	2.7	EJB	AMV	C136
▲ 17-04, S-4*	7.5	GP	Poorly Graded Gravel with Sand		63	33	4.0		EJB	AMV	C136
◆ 17-04, S-5*	10.0	GP	Poorly Graded Gravel with Sand		53	43	4.0		EJB	AMV	C136

Geotechnical Findings Report
GVEA Fuel Storage Facility
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GRAIN SIZE DISTRIBUTION
BORING 17-04

June 2017 31-1-20006-001R1

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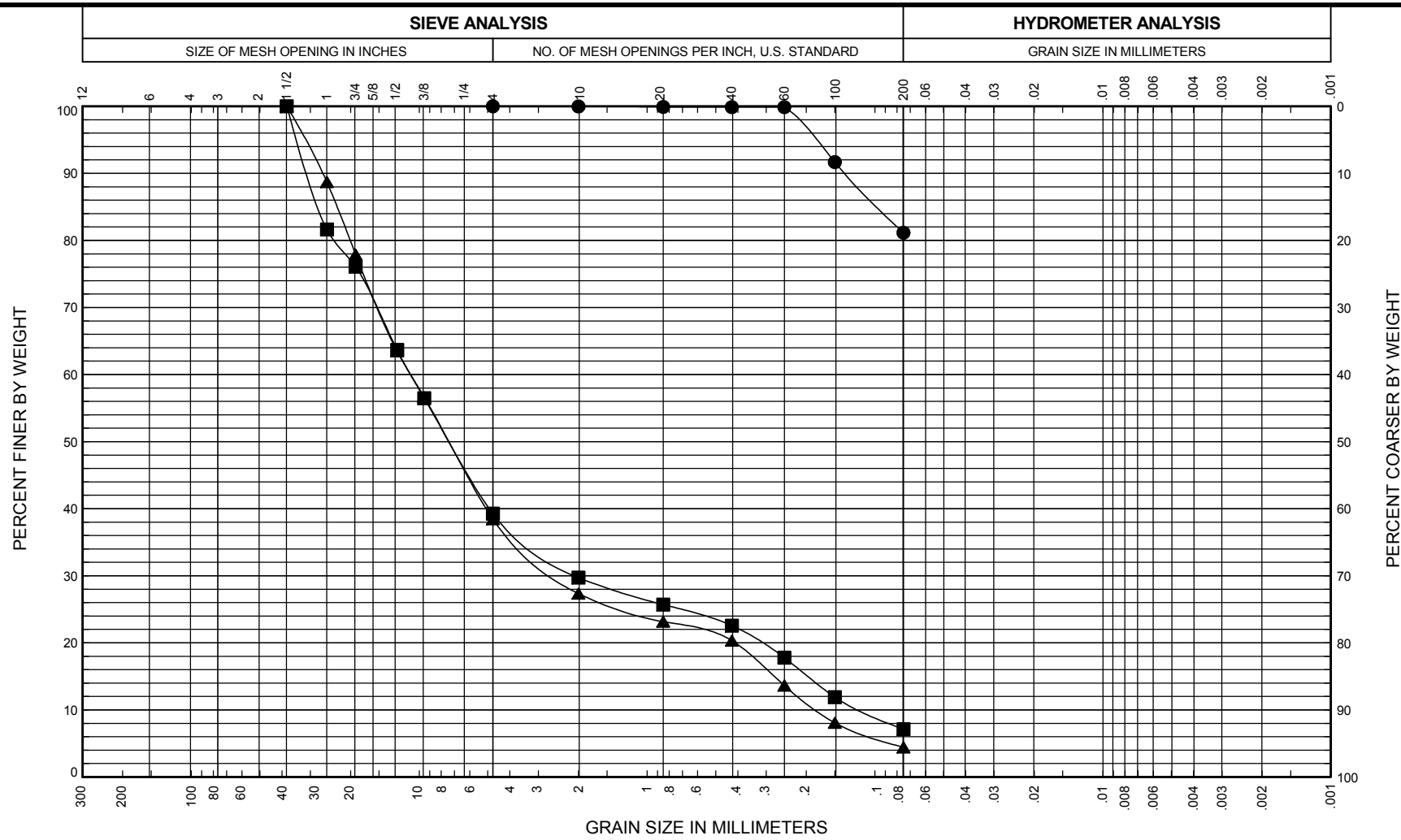
FIG. B-4
Sheet 1 of 1

FIG. B-4

** Sample specimen weight did not meet required minimum mass for ASTM test method.*

PDC Engineers, Inc.

AASHTO GSA MAIN 31-1-20006-001.GPJ SHAN WIL.GDT 6/1/17



BORING AND SAMPLE NO.	DEPTH (feet)	U.S.C.S. SYMBOL	SOIL CLASSIFICATION	COBBLE %	GRAVEL %	SAND %	FINES %	NAT. W.C. %	TEST BY	REVIEW BY	ASTM STD
● 17-05, 3b	5.5	ML	Silt with Sand			19	81.1	32.1	EJB	AMV	C136
■ 17-05, S-4*	7.5	GP-GM	Poorly Graded Gravel with Silt and Sand		61	32	7.1	5.3	ALW	AMV	C136
▲ 17-05, S-5*	10.0	GP	Poorly Graded Gravel with Sand		62	34	4.4		ALW	AMV	C136

Geotechnical Findings Report
GVEA Fuel Storage Facility
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GRAIN SIZE DISTRIBUTION
BORING 17-05

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FIG. B-5
Sheet 1 of 1

FIG. B-5

** Sample specimen weight did not meet required minimum mass for ASTM test method.*

PDC Engineers, Inc.

AASHTO GSA MAIN 31-1-20006-001.GPJ SHAN WIL.GDT 6/1/17

APPENDIX C

PROJECT PHOTOGRAPHS



Photograph 1: Drill rig set up at boring location 17-01.



Photograph 2: Sample S-2, boring 17-01, 2.5 feet bgs to 4.0 feet bgs.



Photograph 3: Sample S-4a and S4-b, boring 17-01, 7.5 feet bgs to 9.0 feet bgs.



Photograph 4: Sample S-8, boring 17-01, 17.5 feet bgs to 19.0 feet bgs.



Photograph 5: Sample S-13, boring 17-01, 40.0 feet bgs to 41.5 feet bgs.



Photograph 6: Sample S-16, boring 17-01, 60 feet bgs to 61.5 feet bgs.



Photograph 7: Drill rig set up at boring 17-02.



Photograph 8: Sample S-2, boring 17-02, 2.5 feet bgs to 4.0 feet bgs.



Photograph 9: Sample 3, boring 17-02, 7.5 feet bgs to 9.0 feet bgs.



Photograph 10: Sample S-8, boring 17-02, 17.5 feet bgs to 19.0 feet bgs.



Photograph 11: Sample S-12, boring 17-02, 35.0 feet bgs to 36.5 feet bgs.



Photograph 12: Sample S-16, boring 17-02, 60.0 feet bgs to 61.5 feet bgs.



Photograph 13: Drill rig set up at boring 17-03.



Photograph 16: Sample S-13, boring 17-03, 40.0 feet bgs to 41.5 feet bgs.



Photograph 14: Sample S-2, boring 17-03, 2.5 feet bgs to 4.0 feet bgs.



Photograph 17: Sample S-16, boring 17-03, 60.0 feet bgs to 61.5 feet bgs.



Photograph 15: Sample S-10, boring 17-01, 25.0 feet bgs to 26.5 feet bgs.



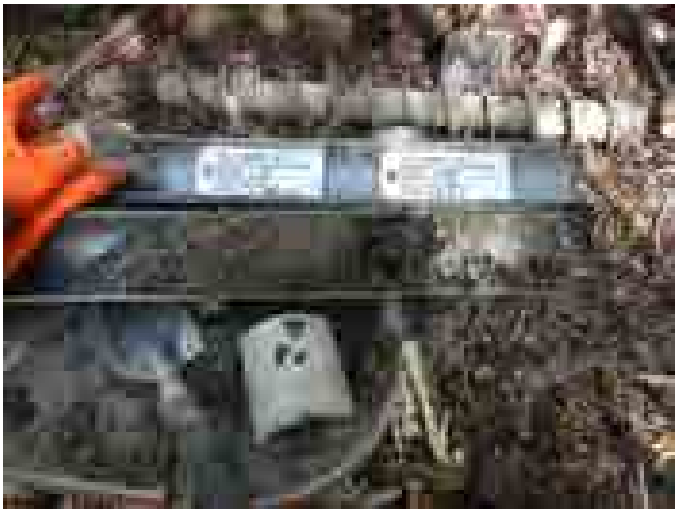
Photograph 18: Drill rig set up at boring 17-04.



Photograph 19: Sample S-1 (grab), boring 17-04, 0.5 feet bgs to 2.0 feet bgs.



Photograph 22: Sample S-10, boring 17-04, 25.0 feet bgs to 26.5 feet bgs.



Photograph 20: Sample S-3a and S-3b, boring 17-04, 5.0 feet bgs to 6.5 feet bgs.



Photograph 23: Sample S-15, boring 17-04, 50.0 feet bgs to 51.5 feet bgs.



Photograph 21: Sample S-5, boring 17-04, 10.0 feet bgs to 11.5 feet bgs.



Photograph 24: Drill rig set up at boring 17-05.



Photograph 25: Sample S-2, boring 17-05, 2.5 feet bgs to 4.0 feet bgs.



Photograph 28: Sample S-9a and S-9b, boring 17-05, 20.0 feet bgs to 21.5 feet bgs.



Photograph 26: Sample S-4, boring 17-05, 7.5 feet bgs to 9.0 feet bgs.



Photograph 29: Sample S-13, boring 17-05, 40 feet bgs to 41.5 feet bgs.



Photograph 27: Sample S-6, boring 17-05, 12.5 feet bgs to 14.0 feet bgs.



Photograph 27: Sample S-16, boring 17-05, 60.0 feet bgs to 61.5 feet bgs.

APPENDIX D

IMPORTANT INFORMATION ABOUT YOUR GEOTECHNICAL / ENVIRONMENTAL REPORT

SHANNON & WILSON, INC.
GEOTECHNICAL AND ENVIRONMENTAL CONSULTANTS

Attachment to and part of Report: 31-1-20006-001R1

Date: June 2017

To: PDC Engineers, Inc.
Attn: Mr. Keith Hanneman, P.E.

Re: Geotechnical Findings Report, GVEA Fuel Storage Facility

IMPORTANT INFORMATION ABOUT YOUR GEOTECHNICAL/ENVIRONMENTAL REPORT

CONSULTING SERVICES ARE PERFORMED FOR SPECIFIC PURPOSES AND FOR SPECIFIC CLIENTS.

Consultants prepare reports to meet the specific needs of specific individuals. A report prepared for a civil engineer may not be adequate for a construction contractor or even another civil engineer. Unless indicated otherwise, your consultant prepared your report expressly for you and expressly for the purposes you indicated. No one other than you should apply this report for its intended purpose without first conferring with the consultant. No party should apply this report for any purpose other than that originally contemplated without first conferring with the consultant.

THE CONSULTANT'S REPORT IS BASED ON PROJECT-SPECIFIC FACTORS.

A geotechnical/environmental report is based on a subsurface exploration plan designed to consider a unique set of project-specific factors. Depending on the project, these may include: the general nature of the structure and property involved; its size and configuration; its historical use and practice; the location of the structure on the site and its orientation; other improvements such as access roads, parking lots, and underground utilities; and the additional risk created by scope-of-service limitations imposed by the client. To help avoid costly problems, ask the consultant to evaluate how any factors that change subsequent to the date of the report may affect the recommendations. Unless your consultant indicates otherwise, your report should not be used: (1) when the nature of the proposed project is changed (for example, if an office building will be erected instead of a parking garage, or if a refrigerated warehouse will be built instead of an unrefrigerated one, or chemicals are discovered on or near the site); (2) when the size, elevation, or configuration of the proposed project is altered; (3) when the location or orientation of the proposed project is modified; (4) when there is a change of ownership; or (5) for application to an adjacent site. Consultants cannot accept responsibility for problems that may occur if they are not consulted after factors which were considered in the development of the report have changed.

SUBSURFACE CONDITIONS CAN CHANGE.

Subsurface conditions may be affected as a result of natural processes or human activity. Because a geotechnical/environmental report is based on conditions that existed at the time of subsurface exploration, construction decisions should not be based on a report whose adequacy may have been affected by time. Ask the consultant to advise if additional tests are desirable before construction starts; for example, groundwater conditions commonly vary seasonally.

Construction operations at or adjacent to the site and natural events such as floods, earthquakes, or groundwater fluctuations may also affect subsurface conditions and, thus, the continuing adequacy of a geotechnical/environmental report. The consultant should be kept apprised of any such events, and should be consulted to determine if additional tests are necessary.

MOST RECOMMENDATIONS ARE PROFESSIONAL JUDGMENTS.

Site exploration and testing identifies actual surface and subsurface conditions only at those points where samples are taken. The data were extrapolated by your consultant, who then applied judgment to render an opinion about overall subsurface conditions. The actual interface between materials may be far more gradual or abrupt than your report indicates. Actual conditions in areas not sampled may differ from those predicted in your report. While nothing can be done to prevent such situations, you and your consultant can work together to help reduce their impacts. Retaining your consultant to observe subsurface construction operations can be particularly beneficial in this respect.

A REPORT'S CONCLUSIONS ARE PRELIMINARY.

The conclusions contained in your consultant's report are preliminary because they must be based on the assumption that conditions revealed through selective exploratory sampling are indicative of actual conditions throughout a site. Actual subsurface conditions can be discerned only during earthwork; therefore, you should retain your consultant to observe actual conditions and to provide conclusions. Only the consultant who prepared the report is fully familiar with the background information needed to determine whether or not the report's recommendations based on those conclusions are valid and whether or not the contractor is abiding by applicable recommendations. The consultant who developed your report cannot assume responsibility or liability for the adequacy of the report's recommendations if another party is retained to observe construction.

THE CONSULTANT'S REPORT IS SUBJECT TO MISINTERPRETATION.

Costly problems can occur when other design professionals develop their plans based on misinterpretation of a geotechnical/environmental report. To help avoid these problems, the consultant should be retained to work with other project design professionals to explain relevant geotechnical, geological, hydrogeological, and environmental findings, and to review the adequacy of their plans and specifications relative to these issues.

BORING LOGS AND/OR MONITORING WELL DATA SHOULD NOT BE SEPARATED FROM THE REPORT.

Final boring logs developed by the consultant are based upon interpretation of field logs (assembled by site personnel), field test results, and laboratory and/or office evaluation of field samples and data. Only final boring logs and data are customarily included in geotechnical/environmental reports. These final logs should not, under any circumstances, be redrawn for inclusion in architectural or other design drawings, because drafters may commit errors or omissions in the transfer process.

To reduce the likelihood of boring log or monitoring well misinterpretation, contractors should be given ready access to the complete geotechnical engineering/environmental report prepared or authorized for their use. If access is provided only to the report prepared for you, you should advise contractors of the report's limitations, assuming that a contractor was not one of the specific persons for whom the report was prepared, and that developing construction cost estimates was not one of the specific purposes for which it was prepared. While a contractor may gain important knowledge from a report prepared for another party, the contractor should discuss the report with your consultant and perform the additional or alternative work believed necessary to obtain the data specifically appropriate for construction cost estimating purposes. Some clients hold the mistaken impression that simply disclaiming responsibility for the accuracy of subsurface information always insulates them from attendant liability. Providing the best available information to contractors helps prevent costly construction problems and the adversarial attitudes that aggravate them to a disproportionate scale.

READ RESPONSIBILITY CLAUSES CLOSELY.

Because geotechnical/environmental engineering is based extensively on judgment and opinion, it is far less exact than other design disciplines. This situation has resulted in wholly unwarranted claims being lodged against consultants. To help prevent this problem, consultants have developed a number of clauses for use in their contracts, reports, and other documents. These responsibility clauses are not exculpatory clauses designed to transfer the consultant's liabilities to other parties; rather, they are definitive clauses that identify where the consultant's responsibilities begin and end. Their use helps all parties involved recognize their individual responsibilities and take appropriate action. Some of these definitive clauses are likely to appear in your report, and you are encouraged to read them closely. Your consultant will be pleased to give full and frank answers to your questions.

The preceding paragraphs are based on information provided by the
ASFE/Association of Engineering Firms Practicing in the Geosciences, Silver Spring, Maryland

Memo to PDC

Reference: GVEA LNG Siting Study

The following are the pertinent issues associated with siting the LNG facilities to service both GVEA and IGU.

1. I is very difficult to provide much detail for an LNG plant layout without the actual design basis for the facility.
2. I know that there is a preference for single containment storage, because the initial cost is less than full containment. However, Full containment offers many advantages, especially in the planning stages. Therefore, we have performed an initial screening for thermal exclusion for an unconfined LNG storage tank failure, which, in our opinion is what is necessary for preliminary siting.
3. We have offered a site plan for single containment, with a high dike that meets the NFPA X-Y rule.
4. However, the actual layout and configuration of the plant LNG transfer facilities, and their design spill determinations, will be required to determine the thermal exclusion and vapor dispersion requirements.
5. Generally we like to locate design spill containment structure as close to the center of the center of the site as possible to provide the most flexibility for thermal exclusion and vapor dispersion.
6. All LNG transfer activities must be identified and the design LNG spills determined in accordance with the published PHMSA FAQ's
    a. Proposed Trucks per day and method of transfer. Unloading only, or filling and unloading?
    b. Proposed rail cars, of what size, per day and method of transfer. Unloading only, or filling and unloading?
    c. Proposed production rates for each customer of the facility.
    d. Is container filling or unloading foreseen?
7. Any kind of crossing of the existing pipeline ROW should be avoided for a variety of reasons, but mainly cost and schedule.
8. Snow management must be determined in any site plan, as well the allowance for the accumulation of ice and snow in the spill impoundment systems.
9. The configuration of any rail facilities should include a single track, and make it as long as necessary, with one security controlled gate. Most of the facilities I am accustomed to in secure facilities have the tack running in a circle, with a minimum of switches. The prime mover for the cars should never pass the transfer area, or the area must be purged a non-classified electrical area before each transit. (At least I think this is the current DOT thinking)
10. The general technical terms of the potential ownership transaction should be included in the basis of design, flow rates, pressures, and temperature. We are concerned with the complexities of contracting between public utility companies, as they may affect the configuration of the facilities.

ALTERNATIVE 1 COST SUMMARY

	BASE BID		
CIVIL WORK (PROVIDED BY GNE)		$	1,309,250
TANK CONSTRUCTION (PROVIDED BY GNE)		$	3,943,000
STRUCTURAL WORK (PROVIDED BY GNE)		$	160,000
MECHANICAL/PIPING WORK (PROVIDED BY GNE)		$	1,120,500
ELECTRICAL WORK (PROVIDED BY GNE)		$	457,000
SITE WORK		$	110,370
SITE MECHANICAL		$	408,153
SITE COMMUNICATIONS		$	50,436
30'0''X40'0" PUMPHOUSE		$	790,141
30'0''X40'0" CONTROL BUILDING		$	603,915
CONSTRUCTION SUBTOTAL		$	8,952,765
DESIGN FEE AND CA	11%	$	984,804.15
PERMITTING/PLAN REVIEWS		$	20,000
SUBTOTAL		$	9,957,569
CONTINGENCY	50%	$	4,978,784.58
SUBTOTAL		$	14,936,354
	ALTERNATES		
1	ACCESS ROAD - H&H TO GVEA YARD	$	356,912
2	TRUCK LOADING FACILITY (PROVIDED BY GNE)	$	1,266,406
3	TRACK MOBILE AND SHELTER	$	877,500
4	GVEA RAIL RACK, PIPING, TRACK AND SWITCHING	$	2,201,750
5	PETRO STAR RAIL RACK, PIPING, TRACK AND SWITCHING	$	1,361,750
6	IGU RAIL SPUR TRACK AND SWITCHING	$	1,087,500
DESIGN FEE AND CA	11%	$	786,699.94
CONTINGENCY	50%	$	3,969,258.77
CONSTRUCTION SUBTOTAL		$	11,907,776
CONSTRUCTION TOTAL INCLUDING ALTERNATES		$	26,844,130

GOLDEN VALLEY ELECTRIC ASSOC. (GVEA)
PETROLEUM TERMINAL FACILITY
3MM GAL TOTAL STORAGE
OPTION #1

6/26/2017

GNE #17013

Revision C

Task	Sub	Task Description	Units	Qty	Unit Cost	Total
1		**Civil Work**				
	1.01	Excavation for Tank Farm: tank foundations, containment dike	CY	16,500	$6.00	$99,000.00
	1.02	Install geomembrane liner under containment area and within tank ringwalls	SF	106,000	$2.25	$238,500.00
	1.03	Liner Bedding, NFS Backfill, Berm and Compaction	CY	19,750	$28.00	$553,000.00
	1.04	Install Subsurface Drainage System. Catch Basins & OWS	LS	1	$75,000.00	$75,000.00
	1.05	Trenching, Bedding, Compaction for POL Pipeline Installation	LF	2,750	$125.00	$343,750.00
		Task 1 Subtotal				**$1,309,250.00**
2		**Tank 1010 and 1020 Construction (1.5MM Gal ea)**				
	2.01	Tank Foundation Ringwalls - 85' Dia x 5' Deep	EA	2	$122,500.00	$245,000.00
	2.02	Tank CP Anode Grid under tanks	EA	2	$61,500.00	$123,000.00
	2.03	Tank Fabricate, Erection 85' Dia. X 40', Fixed Cone Roof	EA	1	$1,575,000.00	$1,575,000.00
	2.04	Tank Fabricate, Erection 85' Dia. X 40' , Internal Floating Roof	EA	1	$1,650,000.00	$1,650,000.00
	2.05	Field Coatings, Hydro, Appurtenances	EA	2	$175,000.00	$350,000.00
		Task 2 Subtotal				**$3,943,000.00**
3		**Structural Work**				
	3.01	Platform/Handrails/Stairs/Pipe Supports/Catwalks within Diked area	LS	1	$95,000.00	$95,000.00
	3.02	Pipe Supports along external pipe routes	LS	1	$65,000.00	$65,000.00
		Task 3 Subtotal				**$160,000.00**
4		**Mechanical / Piping Work**				
	4.01	10" Cargo piping from Pumphouse to Tanks - A/G	LF	550	$95.00	$52,250.00
	4.02	8" Service piping from Pumphouse to Tanks - A/G	LF	550	$85.00	$46,750.00
	4.03	10" Service piping from Pumphouse to Truck Load/Offload - B/G	LF	1,000	$95.00	$95,000.00
	4.04	6" Service piping from Pumphouse to Truck Load/Offload - B/G	LF	2,000	$76.00	$152,000.00
	4.05	10" Cargo piping from Rail Car Offload to Pump House - B/G	LF	1,650	$95.00	$156,750.00
2	4.06	10" Service piping from Pump House to Rail Car Loading- B/G (Petrostar)	LF	1,650	$95.00	$156,750.00
	4.07	4" Service piping from Pump House to GVEA Transfer Bldg - B/G	LF	1,800	$55.00	$99,000.00
	4.08	4" Service piping from Pump House to Peaker Plant - B/G	LF	1,150	$55.00	$63,250.00
	4.09	3" Service to Fuel Forwarding Bldg - A/G	LF	950	$50.00	$47,500.00
	4.10	10" Cargo pipelines from Petrostar to Pump House - A/G	LF	750	$95.00	$71,250.00
	4.11	600 gpm Pumps for Cargo/Service, Valves and Appurtenances	EA	5	$22,500.00	$112,500.00
	4.12	Filter Vessels, Coalescing Elements, Meters, Flow Control Devices	LS	1	$225,000.00	$225,000.00
	4.13	AFFF Piping from Pump to Foam Chambers and 4" Perimeter Line	LF	1,650	$40.00	$66,000.00
	4.14	AFFF Pump, Control Panel, RBFP, Concentrate Tank, Etc	LS	1	$85,000.00	$85,000.00
	4.15	Foam Chambers	EA	2	$2,500.00	$5,000.00
1 1	4.16	Water Line Extension and Hydrants	LS	1	$0.00	$0.00
	4.17	Supplemental Water Storage Tank	EA	1	$0.00	$0.00
		Task 4 Subtotal				**$1,434,000.00**
5		**Rail Car Offloading/Loading Rack**				
1	5.01	Civil Excavation, NFS Fill, Compaction, Rail Extension	LS	1	$0.00	$0.00
	5.02	Six Position Spill Containement, Bottom Unloading Arms, Metering, Valves	LS	1	$225,000.00	$225,000.00
2	5.03	Six Position Rail Car Rack for Loading, Loading Arms, Platforms (Petrostar)	LS	1	$275,000.00	$275,000.00
		Task 5 Subtotal				**$500,000.00**
6		**Truck Loading Rack (TLR)**				
	6.01	Loading Arm, Rest, Connection, 2 Arms	LS	1	$85,000.00	$85,000.00
	6.02	Terminal Management System	LS	1	$105,000.00	$105,000.00
	6.03	Piping, Valves, meter, strainer	LS	1	$84,500.00	$84,500.00
	6.04	Foundation and Heated Lane Containment Slab	LS	1	$65,000.00	$65,000.00
	6.05	Structural Pipe Supports	LS	1	$20,000.00	$20,000.00
1	6.06	Vapor combustion system foundation and equipment	LS	1	$0.00	$0.00
1 1	6.07	Vapor recovery piping	LS	1	$0.00	$0.00
1 1	6.08	Fire water and Foam System	LS	1	$0.00	$0.00
1	6.09	Additive System	LS	1	$0.00	$0.00

GOLDEN VALLEY ELECTRIC ASSOC. (GVEA)
PETROLEUM TERMINAL FACILITY
3MM GAL TOTAL STORAGE
OPTION #1

6/26/2017

GNE #17013

Revision C

Task	Sub	Task Description	Units	Qty	Unit Cost	Total
	6.1	Scully System	LS	1	$75,000.00	$75,000.00
	6.11	Truck Offload Hose, 6" Piping, Valves, Strainer, Connection, etc.	LS	1	$35,000.00	$35,000.00
		Task 6 Subtotal				**$469,500.00**
7		**Electrical Work**				
	7.01	Power within Tank Farm for CP, MOV's, Lighting, Earth Electrode System	LS	1	$215,000.00	$215,000.00
	7.02	EFSO and Fire Alarm System within Tank Farm	LS	1	$32,000.00	$32,000.00
	7.03	Heat Trace for drainage piping	LS	1	$35,000.00	$35,000.00
	7.04	Tank instruments and conduit routing	LS	1	$75,000.00	$75,000.00
	7.05	New indication panel and computer equipment in control room, TMS	LS	1	$60,000.00	$60,000.00
	7.06	Integration of signals to Ovation System, Programming, Commissioning	LS	1	$40,000.00	$40,000.00
		Task 7 Subtotal				**$457,000.00**
					Construction Cost Subtotal Tasks 1-7	**$8,272,750.00**
					Subtotal Minus Alternate Scope Cost	**$7,841,000.00**
					Permitting/Plan Review Fees	**$15,000.00**
					Contingency (10%)	**$784,100.00**
					GRAND TOTAL	**$8,640,100.00**

Assumptions/ Notes:

1. Not currently in Fuel System Scope, listed for reference only.
2. Alternate scope of work to accommodate Petrostar.

ALTERNATIVE 2 COST SUMMARY

	BASE BID		
CIVIL WORK (PROVIDED BY GNE)		$	1,340,500
TANK CONSTRUCTION (PROVIDED BY GNE)		$	3,943,000
STRUCTURAL WORK (PROVIDED BY GNE)		$	160,000
MECHANICAL/PIPING WORK (PROVIDED BY GNE)		$	1,129,675
ELECTRICAL WORK (PROVIDED BY GNE)		$	457,000
SITE WORK		$	110,370
SITE MECHANICAL		$	352,749
SITE COMMUNICATIONS		$	51,662
30'0''X40'0" PUMPHOUSE		$	787,021
30'0''X40'0" CONTROL BUILDING		$	603,915
CONSTRUCTION SUBTOTAL		$	8,935,892
DESIGN FEE AND CA	11%	$	982,948.12
PERMITTING/PLAN REVIEWS		$	20,000
SUBTOTAL		$	9,938,840
CONTINGENCY	50%	$	4,969,420.06
SUBTOTAL		$	14,908,260
	ALTERNATES		
1	ACCESS ROAD - H&H TO GVEA YARD	$	348,852
2	TRUCK LOADING FACILITY (PROVIDED BY GNE)	$	1,216,365
3	TRACK MOBILE AND SHELTER	$	877,500
4	GVEA RAIL RACK, PIPING, TRACK AND SWITCHING	$	2,137,625
5	PETRO STAR RAIL RACK, PIPING, TRACK AND SWITCHING	$	1,297,625
6	IGU RAIL SPUR TRACK AND SWITCHING	$	1,087,500
DESIGN FEE AND CA	11%	$	766,201.34
CONTINGENCY	50%	$	3,865,834.02
CONSTRUCTION SUBTOTAL		$	11,597,502
CONSTRUCTION TOTAL INCLUDING ALTERNATES		$	26,505,762

GOLDEN VALLEY ELECTRIC ASSOC. (GVEA)
PETROLEUM TERMINAL FACILITY
3MM GAL TOTAL STORAGE
OPTION #2

6/26/2017

GNE #17013

Revision C

Task	Sub	Task Description	Units	Qty	Unit Cost	Total
1		**Civil Work**				
	1.01	Excavation for Tank Farm: tank foundations, containment dike	CY	16,500	$6.00	$99,000.00
	1.02	Install geomembrane liner under containment area and within tank ringwalls	SF	106,000	$2.25	$238,500.00
	1.03	Liner Bedding, NFS Backfill, Berm and Compaction	CY	19,750	$28.00	$553,000.00
	1.04	Install Subsurface Drainage System. Catch Basins & OWS	LS	1	$75,000.00	$75,000.00
	1.05	Trenching, Bedding, Compaction for POL Pipeline Installation	LF	3,000	$125.00	$375,000.00
		Task 1 Subtotal				**$1,340,500.00**
2		**Tank 1010 and 1020 Construction (1.5MM Gal ea)**				
	2.01	Tank Foundation Ringwalls - 85' Dia x 5' Deep	EA	2	$122,500.00	$245,000.00
	2.02	Tank CP Anode Grid under tanks	EA	2	$61,500.00	$123,000.00
	2.03	Tank Fabricate, Erection 85' Dia. X 40', Fixed Cone Roof	EA	1	$1,575,000.00	$1,575,000.00
	2.04	Tank Fabricate, Erection 85' Dia. X 40' , Internal Floating Roof	EA	1	$1,650,000.00	$1,650,000.00
	2.05	Field Coatings, Hydro, Appurtenances	EA	2	$175,000.00	$350,000.00
		Task 2 Subtotal				**$3,943,000.00**
3		**Structural Work**				
	3.01	Platform/Handrails/Stairs/Pipe Supports/Catwalks within Diked area	LS	1	$95,000.00	$95,000.00
	3.02	Pipe Supports along external pipe routes	LS	1	$65,000.00	$65,000.00
		Task 3 Subtotal				**$160,000.00**
4		**Mechanical / Piping Work**				
	4.01	10" Cargo piping from Pumphouse to Tanks - A/G	LF	675	$95.00	$64,125.00
	4.02	8" Service piping from Pumphouse to Tanks - A/G	LF	675	$85.00	$57,375.00
	4.03	10" Service piping from Pumphouse to Truck Load/Offload - B/G	LF	150	$95.00	$14,250.00
	4.04	6" Service piping from Pumphouse to Truck Load/Offload - B/G	LF	300	$76.00	$22,800.00
	4.05	10" Cargo piping from Rail Car Offload to Pump House - B/G	LF	975	$95.00	$92,625.00
2	4.06	10" Service piping from Pump House to Rail Car Loading- B/G (Petrostar)	LF	975	$95.00	$92,625.00
	4.07	4" Service piping from Pump House to GVEA Transfer Bldg - B/G	LF	2,550	$55.00	$140,250.00
	4.08	4" Service piping from Pump House to Peaker Plant - B/G	LF	975	$55.00	$53,625.00
	4.09	3" Service to Fuel Forwarding Bldg - A/G	LF	1,700	$50.00	$85,000.00
	4.10	10" Cargo pipelines from Petrostar to Pump House - A/G	LF	2,050	$95.00	$194,750.00
	4.11	600 gpm Pumps for Cargo/Service, Valves and Appurtenances	EA	5	$22,500.00	$112,500.00
	4.12	Filter Vessels, Coalescing Elements, Meters, Flow Control Devices	LS	1	$225,000.00	$225,000.00
	4.13	AFFF Piping from Pump to Foam Chambers and 4" Perimeter Line	LF	1,750	$40.00	$70,000.00
	4.14	AFFF Pump, Control Panel, RBFP, Concentrate Tank, Etc	LS	1	$85,000.00	$85,000.00
	4.15	Foam Chambers	EA	2	$2,500.00	$5,000.00
1 1	4.16	Water Line Extension and Hydrants	LS	1	$0.00	$0.00
	4.17	Supplemental Water Storage Tank	EA	1	$0.00	$0.00
		Task 4 Subtotal				**$1,314,925.00**
5		**Rail Car Offloading/Loading Rack**				
1	5.01	Civil Excavation, NFS Fill, Compaction, Rail Extension	LS	1	$0.00	$0.00
	5.02	Six Position Spill Containement, Bottom Unloading Arms, Metering, Valves	LS	1	$225,000.00	$225,000.00
2	5.03	Six Position Rail Car Rack for Loading, Loading Arms, Platforms (Petrostar)	LS	1	$275,000.00	$275,000.00
		Task 5 Subtotal				**$500,000.00**
6		**Truck Loading Rack (TLR)**				
	6.01	Loading Arm, Rest, Connection, 2 Arms	LS	1	$85,000.00	$85,000.00
	6.02	Terminal Management System	LS	1	$105,000.00	$105,000.00
	6.03	Piping, Valves, meter, strainer	LS	1	$84,500.00	$84,500.00
	6.04	Foundation and Heated Lane Containment Slab	LS	1	$65,000.00	$65,000.00
	6.05	Structural Pipe Supports	LS	1	$20,000.00	$20,000.00
1	6.06	Vapor combustion system foundation and equipment	LS	1	$0.00	$0.00
1 1	6.07	Vapor recovery piping	LS	1	$0.00	$0.00
1 1	6.08	Fire water and Foam System	LS	1	$0.00	$0.00
1	6.09	Additive System	LS	1	$0.00	$0.00

GOLDEN VALLEY ELECTRIC ASSOC. (GVEA)
PETROLEUM TERMINAL FACILITY
3MM GAL TOTAL STORAGE
OPTION #2

6/26/2017

GNE #17013

Revision C

Task	Sub	Task Description	Units	Qty	Unit Cost	Total
	6.1	Scully System	LS	1	$75,000.00	$75,000.00
	6.11	Truck Offload Hose, 6" Piping, Valves, Strainer, Connection, etc.	LS	1	$35,000.00	$35,000.00
		Task 6 Subtotal				**$469,500.00**
7		**Electrical Work**				
	7.01	Power within Tank Farm for CP, MOV's, Lighting, Earth Electrode System	LS	1	$215,000.00	$215,000.00
	7.02	EFSO and Fire Alarm System within Tank Farm	LS	1	$32,000.00	$32,000.00
	7.03	Heat Trace for drainage piping	LS	1	$35,000.00	$35,000.00
	7.04	Tank instruments and conduit routing	LS	1	$75,000.00	$75,000.00
	7.05	New indication panel and computer equipment in control room, TMS	LS	1	$60,000.00	$60,000.00
	7.06	Integration of signals to Ovation System, Programming, Commissioning	LS	1	$40,000.00	$40,000.00
		Task 7 Subtotal				**$457,000.00**
					Construction Cost Subtotal Tasks 1-7	**$8,184,925.00**
					Subtotal Minus Alternate Scope Cost	**$7,817,300.00**
					Permitting/Plan Review Fees	**$15,000.00**
					Contingency (10%)	**$781,730.00**
					GRAND TOTAL	**$8,614,030.00**

Assumptions/ Notes:

1. Not currently in Fuel System Scope, listed for reference only.
2. Alternate scope of work to accommodate Petrostar.

ALTERNATIVE 3 COST SUMMARY

	BASE BID		
CIVIL WORK (PROVIDED BY GNE)		$	1,340,500
TANK CONSTRUCTION (PROVIDED BY GNE)		$	3,943,000
STRUCTURAL WORK (PROVIDED BY GNE)		$	160,000
MECHANICAL/PIPING WORK (PROVIDED BY GNE)		$	1,457,550
ELECTRICAL WORK (PROVIDED BY GNE)		$	457,000
SITE WORK		$	110,370
SITE MECHANICAL		$	439,507
SITE COMMUNICATIONS		$	50,123
30'0''X40'0" PUMPHOUSE		$	787,021
30'0''X40'0" CONTROL BUILDING		$	603,915
CONSTRUCTION SUBTOTAL		$	9,348,986
DESIGN FEE AND CA	11%	$	1,028,388.46
PERMITTING/PLAN REVIEWS		$	20,000
SUBTOTAL		$	10,397,374
CONTINGENCY	50%	$	5,198,687.23
SUBTOTAL		$	15,596,062
	ALTERNATES		
1	ACCESS ROAD - H&H TO GVEA YARD	$	348,852
2	TRUCK LOADING FACILITY (PROVIDED BY GNE)	$	1,356,132
3	TRACK MOBILE AND SHELTER	$	877,500
4	GVEA RAIL RACK, PIPING, TRACK AND SWITCHING	$	2,121,000
5	PETRO STAR RAIL RACK, PIPING, TRACK AND SWITCHING	$	1,281,000
6	IGU RAIL SPUR TRACK AND SWITCHING	$	1,087,500
DESIGN FEE AND CA	11%	$	777,918.20
CONTINGENCY	50%	$	3,924,950.90
CONSTRUCTION SUBTOTAL		$	11,774,853
CONSTRUCTION TOTAL INCLUDING ALTERNATES		$	27,370,914

GOLDEN VALLEY ELECTRIC ASSOC. (GVEA)
PETROLEUM TERMINAL FACILITY
3MM GAL TOTAL STORAGE
OPTION #3

6/26/2017

GNE #17013

Revision C

Task	Sub	Task Description	Units	Qty	Unit Cost	Total
1		**Civil Work**				
	1.01	Excavation for Tank Farm: tank foundations, containment dike	CY	16,500	$6.00	$99,000.00
	1.02	Install geomembrane liner under containment area and within tank ringwalls	SF	106,000	$2.25	$238,500.00
	1.03	Liner Bedding, NFS Backfill, Berm and Compaction	CY	19,750	$28.00	$553,000.00
	1.04	Install Subsurface Drainage System. Catch Basins & OWS	LS	1	$75,000.00	$75,000.00
	1.05	Trenching, Bedding, Compaction for POL Pipeline Installation	LF	3,000	$125.00	$375,000.00
		Task 1 Subtotal				**$1,340,500.00**
2		**Tank 1010 and 1020 Construction (1.5MM Gal ea)**				
	2.01	Tank Foundation Ringwalls - 85' Dia x 5' Deep	EA	2	$122,500.00	$245,000.00
	2.02	Tank CP Anode Grid under tanks	EA	2	$61,500.00	$123,000.00
	2.03	Tank Fabricate, Erection 85' Dia. X 40', Fixed Cone Roof	EA	1	$1,575,000.00	$1,575,000.00
	2.04	Tank Fabricate, Erection 85' Dia. X 40' , Internal Floating Roof	EA	1	$1,650,000.00	$1,650,000.00
	2.05	Field Coatings, Hydro, Appurtenances	EA	2	$175,000.00	$350,000.00
		Task 2 Subtotal				**$3,943,000.00**
3		**Structural Work**				
	3.01	Platform/Handrails/Stairs/Pipe Supports/Catwalks within Diked area	LS	1	$95,000.00	$95,000.00
	3.02	Pipe Supports along external pipe routes	LS	1	$65,000.00	$65,000.00
		Task 3 Subtotal				**$160,000.00**
4		**Mechanical / Piping Work**				
	4.01	10" Cargo piping from Pumphouse to Tanks - A/G	LF	1,500	$95.00	$142,500.00
	4.02	8" Service piping from Pumphouse to Tanks - A/G	LF	1,500	$85.00	$127,500.00
	4.03	10" Service piping from Pumphouse to Truck Load/Offload - B/G	LF	150	$95.00	$14,250.00
	4.04	6" Service piping from Pumphouse to Truck Load/Offload - B/G	LF	300	$76.00	$22,800.00
	4.05	10" Cargo piping from Rail Car Offload to Pump House - B/G	LF	800	$95.00	$76,000.00
2	4.06	10" Service piping from Pump House to Rail Car Loading- B/G (Petrostar)	LF	800	$95.00	$76,000.00
	4.07	4" Service piping from Pump House to GVEA Transfer Bldg - B/G	LF	2,750	$55.00	$151,250.00
	4.08	4" Service piping from Pump House to Peaker Plant - B/G	LF	1,150	$55.00	$63,250.00
	4.09	3" Service to Fuel Forwarding Bldg - A/G	LF	1,900	$50.00	$95,000.00
	4.10	10" Cargo pipelines from Petrostar to Pump House - A/G	LF	3,300	$95.00	$313,500.00
	4.11	600 gpm Pumps for Cargo/Service, Valves and Appurtenances	EA	5	$22,500.00	$112,500.00
	4.12	Filter Vessels, Coalescing Elements, Meters, Flow Control Devices	LS	1	$225,000.00	$225,000.00
	4.13	AFFF Piping from Pump to Foam Chambers and 4" Perimeter Line	LF	2,500	$40.00	$100,000.00
	4.14	AFFF Pump, Control Panel, RBFP, Concentrate Tank, Etc	LS	1	$85,000.00	$85,000.00
	4.15	Foam Chambers	EA	2	$2,500.00	$5,000.00
1	4.16	Water Line Extension and Hydrants	LS	1	$0.00	$0.00
1	4.17	Supplemental Water Storage Tank	EA	1	$0.00	$0.00
		Task 4 Subtotal				**$1,609,550.00**
5		**Rail Car Offloading/Loading Rack**				
1	5.01	Civil Excavation, NFS Fill, Compaction, Rail Extension	LS	1	$0.00	$0.00
	5.02	Six Position Spill Containement, Bottom Unloading Arms, Metering, Valves	LS	1	$225,000.00	$225,000.00
2	5.03	Six Position Rail Car Rack for Loading, Loading Arms, Platforms (Petrostar)	LS	1	$275,000.00	$275,000.00
		Task 5 Subtotal				**$500,000.00**
6		**Truck Loading Rack (TLR)**				
	6.01	Loading Arm, Rest, Connection, 2 Arms	LS	1	$85,000.00	$85,000.00
	6.02	Terminal Management System	LS	1	$105,000.00	$105,000.00
	6.03	Piping, Valves, meter, strainer	LS	1	$84,500.00	$84,500.00
	6.04	Foundation and Heated Lane Containment Slab	LS	1	$65,000.00	$65,000.00
	6.05	Structural Pipe Supports	LS	1	$20,000.00	$20,000.00
1	6.06	Vapor combustion system foundation and equipment	LS	1	$0.00	$0.00
1	6.07	Vapor recovery piping	LS	1	$0.00	$0.00
1	6.08	Fire water and Foam System	LS	1	$0.00	$0.00
1	6.09	Additive System	LS	1	$0.00	$0.00

GOLDEN VALLEY ELECTRIC ASSOC. (GVEA)
PETROLEUM TERMINAL FACILITY
3MM GAL TOTAL STORAGE
OPTION #3

6/26/2017

GNE #17013

Revision C

Task	Sub	Task Description	Units	Qty	Unit Cost	Total
	6.1	Scully System	LS	1	$75,000.00	$75,000.00
	6.11	Truck Offload Hose, 6" Piping, Valves, Strainer, Connection, etc.	LS	1	$35,000.00	$35,000.00
		Task 6 Subtotal				**$469,500.00**
7		**Electrical Work**				
	7.01	Power within Tank Farm for CP, MOV's, Lighting, Earth Electrode System	LS	1	$215,000.00	$215,000.00
	7.02	EFSO and Fire Alarm System within Tank Farm	LS	1	$32,000.00	$32,000.00
	7.03	Heat Trace for drainage piping	LS	1	$35,000.00	$35,000.00
	7.04	Tank instruments and conduit routing	LS	1	$75,000.00	$75,000.00
	7.05	New indication panel and computer equipment in control room, TMS	LS	1	$60,000.00	$60,000.00
	7.06	Integration of signals to Ovation System, Programming, Commissioning	LS	1	$40,000.00	$40,000.00
		Task 7 Subtotal				**$457,000.00**
					Construction Cost Subtotal Tasks 1-7	**$8,479,550.00**
					Subtotal Minus Alternate Scope Cost	**$8,128,550.00**
					Permitting/Plan Review Fees	**$15,000.00**
					Contingency (10%)	**$812,855.00**
					GRAND TOTAL	**$8,956,405.00**

Assumptions/ Notes:

1. Not currently in Fuel System Scope, listed for reference only.
2. Alternate scope of work to accommodate Petrostar.

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GVEA
Alternative BACT
November 2018

Attachment 3
Leidos Strategic Fuel Evaluation

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BACT Analysis of Zehnder and North Pole Power Plants: Use of Low Sulfur Fuels

Delma Bratvold
Energy Analyst
Leidos Engineering
July 2017

The North Pole Power Plant (NPPP) has two GE Frame 7 combustion turbines (GT1 and GT2) and the Zehnder Power Plant has two GE Frame 5 combustion turbines. In 2016, high sulfur diesel comprised 85% of the fuel burned in the North Pole Plant and 98% of the fuel burned in the Zehnder Plant. However, the turbines at both of these plants are capable of burning 100% ultra low sulfur diesel (ULSD). An analysis of the capital investment required for burning 100% ULSD at both the North Pole Power Plant and the Zehnder Power Plant is described below.

1 Needed ULSD Storage Volume

Two scenarios of ULSD storage volume are considered. In the first scenario, the needed storage volume is based on maximum permitted operation of both the NPPP and the Zehnder Plant. In the second scenario, storage volume is based on historic maximum fuel energy use at these plants.

ULSD is produced in Alaska at two refineries: one is 350 miles away in Valdez; the other is 530 miles away in Kenai. Both of these refineries have, or are in the process of establishing bulk storage at marine terminals in Anchorage, which is 370 miles from away. Both refineries are likely to transport bulk ULSD to North Pole through their Anchorage terminals to allow rail transport, which is not directly available from the refineries themselves. The quantities of ULSD required for NPPP and Zehnder operation are preferentially transported by rail rather than truck due to: difficult winter road conditions; periodic regional shortages of truck drivers; and economies of scale in transport by 30,000 gallon railcars versus tank trucks with a maximum load of around 9,000 gallons.

With no delays, rail transport from Anchorage to North Pole is 3 days one way, and 7 days round trip including fuel loading and off-loading. Shipments are assumed to arrive twice a week, and at any one time, half the railcars will be headed towards or in North Pole and the other half will be headed towards or in Anchorage. This requires an operational storage volume equivalent to 3 ½ days of fuel. The longer transport chain for ULSD from Anchorage compared to high sulfur diesel produced in North Pole poses additional delivery risk which is mitigated with North Pole fuel storage capacity that allows for reasonable delivery delays. The Alaska Railroad has stated that in the event of destruction of one of the higher rail bridges between Anchorage and North Pole (e.g., such as due to an avalanche), bridge replacement may take up to 4 days. Thus, fuel storage capacity should be equivalent to a total of 7 ½ days of fuel (i.e., 3 ½ days for operational fuel plus 4 additional days for reasonable delivery delays).

Under the first scenario, with maximum permitted use of NPPP and Zehnder Power Plant, maximum permitted levels are calculated based on the number of days for round-trip fuel deliveries, the potential over-lap in their days of operation, and maximum daily fuel burn rates. The emissions permit for the Zehnder Power Plant allows operation of both GT1 and GT2 365 days per year. The emission permit for NPPP GT2 allows a maximum of 7,992 hours per year by, equivalent to 333 days per year. Maximum use of the NPPP GT1 is limited based on a shared NOx emissions permit, from which maximum operation is

estimated to be 3,794 hours,[1] which is equivalent to 158 days per year. Based on the maximum permitted usage of the NPPP and Zehnder Plants, ULSD storage needs to be adequate for simultaneous operation of both NPPP units and both Zehnder units on a continuous basis for months at a time.

NPPP GT1 and GT2 each burn 672 MMBtu per hour, equivalent to a combined 32,256 MMBtu per day. Zehnder GT1 and GT2 each burn 268 MMBtu per hour, equivalent to a combined 12,864 MMBtu per day. Assuming use of ULSD #1 (winter fuel) with a lower heating value of 124,000 Btu/gallon, the combined maximum daily use of ULSD at both of these plants is 363,871 gallons. Multiplied by 7 ½ days (i.e., 3 ½ days regular delivery plus 4 days delay), this daily use volume corresponds to 2.73 million gallons of new storage capacity.

Under the second scenario, storage volume is based on the maximum 3-day fuel energy use at NPPP and Zehnder over the last decade. A 3-day maximum is used because this duration is approximately equal to the one-way delivery period. The maximum is used (rather than the average) to assure adequate fuel supply during winter cold spells. The 3-day maximum since January 2007 occurred in April 2009, when 62,751 MMBtu were consumed at NPP and Zehnder, equivalent to 506,057 gallons of ULSD #1. The average daily use rate during the 3-day maximum is applied to 7 ½ days storage, yielding 1.27million gallons of new storage capacity.

2 Storage and Transport Component Costs

GVEA owns a site in North Pole that is conducive for construction of shared bulk fuel storage for the NPPP and Zehnder Plant. The complete fuel transport chain from Anchorage is assumed to include rail delivery to bulk storage in North Pole with new rail siding and offloading equipment; new rail tankcars; new bulk storage including pipeline transport of ULSD to NPPP GT1 and GT2; and truck loading and transport of ULSD from North Pole storage to the Zehnder Plant in Fairbanks (approximately 10 miles each way).[2] Estimated costs of these components are shown in the table below.

Table 1. Fuel Storage and Transport Capital Costs under Permitted Maximum Use Scenario and Historic Maximum Use Scenario.

Capital Cost Elements	**Permitted Maximum Use**	**Historic Maximum Use**
Rail siding, rail/truck loading/offloading	$4,500,000	$4,500,000
Rail tank cars *(30,000 gallons, $135,000 each)*	$11,475,000	$5,400,000
Storage construction	$14,300,000	$11,000,000
Tanker truck *(1 truck @ 9,000 gallons)*	$150,000	$150,000
TOTAL	**$30,425,000**	**$21,050,000**

[1] The NPPP GT1 annual use estimate is calculated from the NOx emissions permit for 1600 tons per year for combined emissions from NPPP GT1 and the NPEP GT3, the later of which only burns low sulfur fuels. If NPEP GT3 (the more efficient unit) is run 24/7, assuming a burn rate of 455 MMBtu/hr and NOx emission rate of 0.24 lb/MMBtu, 478 tons NOx will be emitted annually from GT3, leaving 1,122 tons that may be emitted from GT1. Assuming a NOx emission rate of 0.88 lb/MMBtu for GE Frame 7 turbines, the GT1 may burn 2,549,327 MMBtu per year, which at a burn rate of 672 MMBtu/hr corresponds to 3,794 hours.

[2] The Zehnder plant already has 100,000 gallons of storage on site, compared to the estimated 103,742 gallons of ULSD that would be burned daily at this site when operating at maximum capacity.

Storage construction cost and rail siding, rail/truck loading/offloading costs shown above are based on a July 2017 estimate developed by PDC Engineers for a 3 million-gallon storage facility in North Pole, AK.[3] The PDC estimate was adjusted with volume-proportionate reductions in tank construction, civil, and structural costs to represent 2.73 and 1.27 million gallons for the "Permitted Maximum Use" and "Historic Maximum Use" scenarios, respectively. Components in the estimate that are not applicable for the scope of NPPP and Zehnder fuel storage, rail offloading, and truck loading were removed. Other components (i.e., electrical, piping, mechanical, etc.) are assumed to not change significantly over this size range. Rail tank car costs are based on a June 2017 quote from Greenbrier, Inc., and does not include the cost of car delivery from the Lower 48 to Alaska. Tanker truck cost is based on online listings for truck sales.

[3] This cost estimate was developed for consideration of storage to supply all GVEA liquid fuel power plants during potential strategic events. No strategic storage investment decision has been made.

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Attachment 4
January 2017 through October 2018 Fuel Prices

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GVEA Fuel Pricing per Gallon

			Average	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-18	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18
North Pole	LSR Naphtha	PSI Base Price		-	$1.329	$1.071	$1.083	$1.022	$1.004	$0.999	$1.055	$1.056	$1.200	$1.418	$1.561	$1.584	$1.540	$1.494	$1.516	$1.682	$1.641	$1.713	$1.716	$1.779	$1.785
		PSI & Federal surcharges *		-	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
		Total $/Gallon	**$1.396**	**-**	**$1.332**	**$1.074**	**$1.086**	**$1.025**	**$1.007**	**$1.002**	**$1.058**	**$1.059**	**$1.203**	**$1.421**	**$1.564**	**$1.587**	**$1.543**	**$1.497**	**$1.519**	**$1.685**	**$1.644**	**$1.716**	**$1.719**	**$1.782**	**$1.788**
	DF2+10	PSI Base Price		-	-	-	-	$1.625	$1.576	$1.621	$1.708	-	-	-	-	-	-	-	-	$2.150	$2.286	$2.395	$2.400	$2.408	-
		PSI & Federal surcharges *		-	-	-	-	$0.003	$0.003	$0.003	$0.003	-	-	-	-	-	-	-	-	$0.003	$0.003	$0.003	$0.003	$0.003	-
		PSI Ops Surcharge		-	-	-	-	$0.05	$0.05	$0.05	$0.05	-	-	-	-	-	-	-	-	$0.05	$0.05	$0.05	$0.05	$0.05	-
		Delivery Charge		-	-	-	-	$0.020	$0.020	$0.020	$0.020	-	-	-	-	-	-	-	-	$0.020	$0.020	$0.020	$0.020	$0.020	-
		Delivery Fuel Surcharge %		-	-	-	-	20.5%	20.5%	20.5%	19.0%	-	-	-	-	-	-	-	-	29.0%	27.0%	27.0%	23.5%	26.0%	-
		Delivery Fuel Surchage (%*Delivery)		-	-	-	-	$0.004	$0.004	$0.004	$0.004	-	-	-	-	-	-	-	-	$0.006	$0.005	$0.005	$0.005	$0.005	-
		Total $/Gallon	**$2.097**	**-**	**-**	**-**	**-**	**$1.702**	**$1.653**	**$1.699**	**$1.785**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**$2.229**	**$2.364**	**$2.474**	**$2.478**	**$2.486**	**-**
	DF2-15	PSI Base Price		$1.750	$1.797	$1.712	$1.732	-	-	-	-	$1.874	$1.911	$2.040	$2.021	$2.174	$2.204	$2.188	$2.175	-	-	-	-	-	$2.499
		PSI & Federal surcharges *		$0.003	$0.003	$0.003	$0.003	-	-	-	-	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	-	-	-	-	-	$0.003
		PSI Ops Surcharge		$0.04	$0.05	$0.05	$0.05	-	-	-	-	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	-	-	-	-	-	$0.05
		Truck Delivery		$0.020	$0.020	$0.020	$0.020	-	-	-	-	$0.020	$0.020	$0.020	$0.020	$0.020	$0.020	$0.020	$0.020	-	-	-	-	-	$0.020
		Delivery Fuel Surcharge %		18.5%	20.5%	20.5%	20.5%	-	-	-	-	23.0%	23.0%	23.0%	23.0%	24.0%	26.0%	26.0%	26.0%	-	-	-	-	-	26.0%
		Delivery Fuel Surchate (%*Delivery)		$0.004	$0.004	$0.004	$0.004	-	-	-	-	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	-	-	-	-	-	$0.005
		Total $/Gallon	**$2.083**	**$1.817**	**$1.874**	**$1.789**	**$1.809**	**-**	**-**	**-**	**-**	**$1.951**	**$1.989**	**$2.117**	**$2.099**	**$2.251**	**$2.282**	**$2.266**	**$2.253**	**-**	**-**	**-**	**-**	**-**	**$2.577**
	ULSD	PSI Base Price		$1.963	$1.904	$1.805	$1.852	$1.806	$1.703	$1.622	$1.797	$2.074	$2.107	$2.159	$2.038	$2.129	$2.083	$2.083	$2.309	$2.417	$3.129	$2.301	$2.225	$2.308	$2.406
		PSI & Federal surcharges *		$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
		PSI Delivery Charge		$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155
		PSI Fuel Surcharge %		16.5%	17.5%	17.5%	16.5%	16.5%	16.5%	16.5%	14.5%	16.5%	16.5%	19.5%	20.0%	19.0%	20.0%	20.0%	20.0%	21.5%	22.5%	22.5%	22.0%	21.0%	22.0%
		PSI Fuel Surcharge (%*Delivery)		$0.026	$0.027	$0.027	$0.026	$0.026	$0.026	$0.026	$0.022	$0.026	$0.026	$0.030	$0.031	$0.029	$0.031	$0.031	$0.031	$0.033	$0.035	$0.035	$0.034	$0.033	$0.034
		PSI Truck Freight %		15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
		PSI Truck Freight (%*Delivery+Surchage)		$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028
		Truck Delivery		$0.133	$0.133	$0.133	$0.133	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165
		Delivery Fuel Surcharge %		18.5%	20.5%	20.5%	20.5%	20.5%	20.5%	20.5%	19.0%	23.0%	23.0%	23.0%	23.0%	24.0%	26.0%	26.0%	26.0%	29.0%	27.0%	27.0%	23.5%	26.0%	26.0%
		Delivery Fuel Surchage (%*Delivery)		$0.025	$0.027	$0.027	$0.027	$0.034	$0.034	$0.034	$0.031	$0.038	$0.038	$0.038	$0.038	$0.040	$0.043	$0.043	$0.043	$0.048	$0.045	$0.045	$0.039	$0.043	$0.043
		Total $/Gallon	**$2.512**	**$2.331**	**$2.277**	**$2.178**	**$2.223**	**$2.216**	**$2.112**	**$2.032**	**$2.200**	**$2.487**	**$2.521**	**$2.578**	**$2.458**	**$2.549**	**$2.508**	**$2.508**	**$2.734**	**$2.849**	**$3.560**	**$2.732**	**$2.649**	**$2.735**	**$2.834**
Zehnder	DF2+10	PSI Base Price		-	-	-	-	$1.625	$1.576	$1.621	$1.708	-	-	-	-	-	-	-	-	$2.150	$2.286	$2.395	$2.400	$2.408	-
		PSI & Federal surcharges *		-	-	-	-	$0.003	$0.003	$0.003	$0.003	-	-	-	-	-	-	-	-	$0.003	$0.003	$0.003	$0.003	$0.003	-
		PSI Ops Surcharge		-	-	-	-	$0.05	$0.05	$0.05	$0.05	-	-	-	-	-	-	-	-	$0.05	$0.05	$0.05	$0.05	$0.05	-
		Delivery Charge		-	-	-	-	$0.030	$0.030	$0.030	$0.030	-	-	-	-	-	-	-	-	$0.030	$0.030	$0.030	$0.030	$0.030	-
		Delivery Fuel Surcharge %		-	-	-	-	20.5%	20.5%	20.5%	19.0%	-	-	-	-	-	-	-	-	29.0%	27.0%	27.0%	23.5%	26.0%	-
		Delivery Fuel Surchage (%*Delivery)		-	-	-	-	$0.006	$0.006	$0.006	$0.006	-	-	-	-	-	-	-	-	$0.009	$0.008	$0.008	$0.007	$0.008	-
		Total $/Gallon	**$2.109**	**-**	**-**	**-**	**-**	**$1.714**	**$1.665**	**$1.711**	**$1.797**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**$2.242**	**$2.377**	**$2.487**	**$2.490**	**$2.499**	**-**
	DF2-15	PSI Base Price		$1.750	$1.797	$1.712	$1.732	-	-	-	-	$1.874	$1.911	$2.040	$2.021	$2.174	$2.204	$2.188	$2.175	-	-	-	-	-	$2.499
		PSI & Federal surcharges *		$0.003	$0.003	$0.003	$0.003	-	-	-	-	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	-	-	-	-	-	$0.003
		PSI Ops Surcharge		$0.04	$0.05	$0.05	$0.05	-	-	-	-	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	-	-	-	-	-	$0.05
		Truck Delivery		$0.025	$0.025	$0.025	$0.025	-	-	-	-	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	-	-	-	-	-	$0.030
		Delivery Fuel Surcharge %		18.5%	20.5%	20.5%	20.5%	-	-	-	-	23.0%	23.0%	23.0%	23.0%	24.0%	26.0%	26.0%	26.0%	-	-	-	-	-	26.0%
		Delivery Fuel Surchate (%*Delivery)		$0.005	$0.005	$0.005	$0.005	-	-	-	-	$0.007	$0.007	$0.007	$0.007	$0.007	$0.008	$0.008	$0.008	-	-	-	-	-	$0.008
		Total $/Gallon	**$2.093**	**$1.823**	**$1.880**	**$1.795**	**$1.815**	**-**	**-**	**-**	**-**	**$1.964**	**$2.001**	**$2.129**	**$2.111**	**$2.264**	**$2.294**	**$2.279**	**$2.266**	**-**	**-**	**-**	**-**	**-**	**$2.590**
	ULSD	PSI Base Price		$1.963	$1.904	$1.805	$1.852	$1.806	$1.703	$1.622	$1.797	$2.074	$2.107	$2.159	$2.038	$2.129	$2.083	$2.083	$2.309	$2.417	$3.129	$2.301	$2.225	$2.308	$2.406
		PSI & Federal surcharges *		$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.006	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
		PSI Delivery Charge		$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155
		PSI Fuel Surcharge %		16.5%	17.5%	17.5%	16.5%	16.5%	16.5%	16.5%	14.5%	16.5%	16.5%	19.5%	20.0%	19.0%	20.0%	20.0%	20.0%	21.5%	22.5%	22.5%	22.0%	21.0%	22.0%
		PSI Fuel Surcharge (%*Delivery)		$0.026	$0.027	$0.027	$0.026	$0.026	$0.026	$0.026	$0.022	$0.026	$0.026	$0.030	$0.031	$0.029	$0.031	$0.031	$0.031	$0.033	$0.035	$0.035	$0.034	$0.033	$0.034
		PSI Truck Freight %		15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
		PSI Truck Freight (%*Delivery+Surchage)		$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028
		Truck Delivery		$0.025	$0.025	$0.025	$0.025	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030
		Delivery Fuel Surcharge %		18.5%	20.5%	20.5%	20.5%	20.5%	20.5%	20.5%	19.0%	23.0%	23.0%	23.0%	23.0%	24.0%	26.0%	26.0%	26.0%	29.0%	27.0%	27.0%	23.5%	26.0%	26.0%
		Delivery Fuel Surchage (%*Delivery)		$0.005	$0.005	$0.005	$0.005	$0.006	$0.006	$0.006	$0.006	$0.007	$0.007	$0.007	$0.007	$0.007	$0.008	$0.008	$0.008	$0.009	$0.008	$0.008	$0.007	$0.008	$0.008
		Total $/Gallon	**$2.352**	**$2.203**	**$2.147**	**$2.048**	**$2.093**	**$2.053**	**$1.950**	**$1.869**	**$2.040**	**$2.324**	**$2.355**	**$2.412**	**$2.292**	**$2.382**	**$2.338**	**$2.338**	**$2.564**	**$2.675**	**$3.389**	**$2.560**	**$2.482**	**$2.564**	**$2.664**

Notes: During the time frame shown here, 5,755,774 gallons of DF2+10 and 8,829,573 gallons of DF2-15 were consumed by EU ID's 1 and 2 at the North Pole Plant, giving a weighted average cost differential between No. 2 HSD and ULSD of $0.424 per gallon.

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Attachment 5a
Updated Cost Effectiveness Tables North Pole

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Table 5-1. Summary of Available SO_2 Emission Control Technology

Emission Unit		Available Emission Control Technology
1, 2	Simple Cycle Gas Turbine	ULSD
		Low Sulfur Fuel
		No. 1 HSD
		Good Combustion Practices
5, 6	Combined Cycle Gas Turbine	ULSD
		LSR/Naphtha
		Limited Operation
		Good Combustion Practices
7	Emergency Generator Engine	ULSD
		Low Sulfur Fuel
		Limited Operation
		Good Combustion Practices
11, 12	Propane-Fired Boiler	Low Sulfur Fuel
		Good Combustion Practices

Table 5-2. Summary of Technically Feasible SO_2 Emission Control Technology

Emission Unit		Technically Feasible Control Technology
1, 2	Simple Cycle Gas Turbine	ULSD
		Low Sulfur Fuel
		No. 1 HSD
		Good Combustion Practices
5, 6	Combined Cycle Gas Turbine	ULSD
		Good Combustion Practices and LSR/Naphtha
7	Emergency Generator Engine	ULSD
		Low Sulfur Fuel
		Limited Operation
		Good Combustion Practices
11, 12	Propane-Fired Boiler	Low Sulfur Fuel
		Good Combustion Practices

Table 5-3. Ranking of Technically Feasible SO_2 Emission Control Technology

Emission Unit		Emission Control Technology	Control Efficiency (pct.)	SO_2 Emissions (tpy)	SO_2 Emissions Reduction (tpy)
1	Simple Cycle Turbine	ULSD (0.0015 wt. pct. S)	99.7	4.5	1,481.9
		Low Sulfur Fuel (0.05 wt. pct. S)	90.0	148.6	1,337.8
		No. 1 HSD (0.100 wt. pct. S)	80.0	297.3	1,189.1
		Good Combustion Practices (0.50 wt. pct. S) (existing)	0	1,486.4	0
2	Simple Cycle Turbine	Limited Operation + ULSD (0.0015 wt. pct. S)	99.7	4.1	1,352.0
		Limited Operation + Low Sulfur Fuel (0.05 wt. pct. S)	90.0	135.6	1,220.5
		Limited Operations + No. 1 HSD (0.100 wt. pct. S)	80.0	271.2	1,084.9
		Good Combustion Practices (0.50 wt. pct. S) (existing)	0	1,356.1	0
5, 6	Combined Cycle Gas Turbines (per turbine)	ULSD (0.0015 wt. pct. S)	70.0	3.0	7.1
		LSR/Naphtha (0.0050 wt. pct. S) + Good Combustion Practices (existing)	0	10.1	0.0
7	Emergency Generator Engine	ULSD (0.0015 wt. pct. S) + Limited Operation	98.5	0.00015	0.0099
		Low Sulfur Fuel (0.05 wt. pct. S) + Limited Operation	50	0.005	0.0050
		Limited Operation (0.1 wt. pct. S) (existing)	0	0.01	0
11, 12	Propane-Fired Boiler	Low Sulfur Fuel (existing)	0	0.0002	0

Table 5-4. Annualized Costs for ULSD on the Diesel-fired Simple Cycle Gas Turbine (EU ID 1)

Shaded cells indicate user inputs

Project: GVEA North Pole - $PM_{2.5}$ BACT Analysis (EU ID 1 - GE Frame 7 CT)

Prepared By:
Checked By:
Rev:

Annualized Costs

DIRECT ANNUAL COSTS	QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1) Operating & Maintenance Costs		%			$ -	$ -
(2) Repair & Replacement Costs		%			$ -	$ -
(3) Maintenance Materials		LOT		excluded in this estimate		
(4) Utilities						
(a) ULSD Costs:	45,282,462	GAL	$ 0.424	$ 19,199,764		$ 19,199,764
Total Direct Annual Costs (TDAC)					**TDAC =**	$ 19,199,764
INDIRECT ANNUAL COSTS						
(5) Overhead		%		excluded in this estimate	$ -	$ -
(6) Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
Capital Recovery Factor [see inputs below]	0.0944					
(7) Capital Recovery					**CRF * TCI =**	$ -
Total Indirect Annual Costs (TIAC) (refer to Table 5-10)					**TIAC =**	$ 1,461,566
TOTAL ANNUALIZED COSTS (TAC)					**TAC = (TDAC) + (TIAC) =**	$ 20,661,330

Cost Effectiveness Summary

TOTAL TONS SO_2 AVOIDED PER YEAR	=	1,482
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON PTE)	**(TAC)/(TPY) =**	$ 13,942
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON ACTUAL HISTORIC RUN TIMES, AVOIDING 111 TONS PER YEAR)[1]	**(TAC)/(TPY) =**	$ 25,530
COST EFFECTIVENESS ($ PER TON PM AVOIDED BASED ON 6 TONS SO_2 AVOIDED = 1 TON PM AVOIDED)[2]	**(TAC)/(TPY) =**	$ 153,183

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	20	years

[1] Annual average run hours for EU 1 from 2009-2016 is 833 hours, and the peak in the last four years has been 587 hours. 833 hours equates to 4,305,969 gallons of fuel, a TDAC of $1,791,283, and a TAC of $3,208,769. The capital cost of bulk fuel storage would be less and the TIAC for actuals is shown in Table 5-10. 4,305,969 gallons of .381 wt pct. S replaced with .0015 wt pct. = 111 tons avoided. Monthly testing of No. 2 HSD for 2017 showed 0.381 wt. pct. S. average

[2] Alaska Department of Environmental Conservation, Amendments to State Air Quality Control Plan Vol. III: Appendix III.D.5.7, page 52. In reference to fuel oil emissions, "Ambient sampling and modeling in FNSB indicates that reduction of six tons of SO_X emissions result in the same reduction in ambient $PM_{2.5}$ concentration as the reduction of one ton of directly emitted $PM_{2.5}$".

Table 5-5. Annualized Costs for ULSD on the Diesel-fired Simple Cycle Gas Turbine (EU ID 2)

Shaded cells indicate user inputs

Project: GVEA North Pole - $PM_{2.5}$ BACT Analysis (EU ID 2 - GE Frame 7 CT)

Prepared By:
Checked By:
Rev:

Annualized Costs

DIRECT ANNUAL COSTS	QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1) Operating & Maintenance Costs		%			$ -	$ -
(2) Repair & Replacement Costs		%			$ -	$ -
(3) Maintenance Materials		LOT		excluded in this estimate		
(4) Utilities						
(a) ULSD Costs:	41,312,492	GAL	$ 0.424	$ 17,516,497		$ 17,516,497
Total Direct Annual Costs (TDAC)					TDAC =	$ 17,516,497
INDIRECT ANNUAL COSTS						
(5) Overhead		%		excluded in this estimate	$ -	$ -
(6) Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
Capital Recovery Factor [see inputs below]	0.0944					
(7) Capital Recovery					CRF * TCI =	$ -
Total Indirect Annual Costs (TIAC) **(refer to Table 5-10)**					TIAC =	$ 1,461,566
TOTAL ANNUALIZED COSTS (TAC)					TAC = (TDAC) + (TIAC) =	$ 18,978,063

Cost Effectiveness Summary

TOTAL TONS SO_2 AVOIDED PER YEAR	=	1,352
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON PTE)	(TAC)/(TPY) =	$ 14,037
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON ACTUALS, AVOIDING 330 TONS PER YEAR)[1]	(TAC)/(TPY) =	$ 19,497
COST EFFECTIVENESS ($ PER TON PM AVOIDED BASED ON 6 TONS SO_2 AVOIDED = EQUIVALENT TO 1 TON PM AVOIDED)[2]	(TAC)/(TPY) =	$ 116,981

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	20	years

[1] Annual average run hours for EU 2 from 2009-2016 is 2472 hours, and the peak in the last four years has been 2873 hours. 2472 hours equates to 12,778,338 gallons of fuel, a TDAC of $5,315,789 and a TAC of $6,730,274. The capital cost of bulk fuel storage would be less and the TIAC for actuals is shown in Table 5-10. 12,778,338 gallons of .381 wt pct. S replaced with .0015 wt pct. = 330tons avoided. Monthly testing of No. 2 HSD for 2017 showed 0.381 wt. pct. S. average

[2] Alaska Department of Environmental Conservation, Amendments to State Air Quality Control Plan Vol. III: Appendix III.D.5.7, page 52. In reference to fuel oil emissions, "Ambient sampling and modeling in FNSB indicates that reduction of six tons of SO_x emissions result in the same reduction in ambient $PM_{2.5}$ concentration as the reduction of one ton of directly

Table 5-6. Annualized Costs for ULSD on the Diesel-fired Combined Cycle Gas Turbines (EU IDs 5 and 6)

Shaded cells indicate user inputs

Project: GVEA North Pole - $PM_{2.5}$ BACT Analysis (EU IDs 5 and 6 - GE LM6000PC CT)

Prepared By:
Checked By:
Rev:

Annualized Costs

		QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
DIRECT ANNUAL COSTS							
(1)	Operating & Maintenance Costs		%			$ -	$ -
(2)	Repair & Replacement Costs		%			$ -	$ -
(3)	Maintenance Materials		LOT		excluded in this estimate		
(4)	Utilities						
	(a) ULSD Costs:	30,660,000	GAL	1.117	$ 34,247,220		$ 34,247,220
Total Direct Annual Costs (TDAC)						**TDAC =**	$ 34,247,220
INDIRECT ANNUAL COSTS							
(5)	Overhead		%		excluded in this estimate	$ -	$ -
(6)	Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
	Capital Recovery Factor [see inputs below]	0.0944					
(7)	Capital Recovery					**CRF * TCI =**	$ -
Total Indirect Annual Costs (TIAC)						**TIAC =**	$ -
TOTAL ANNUALIZED COSTS (TAC)						**TAC = (TDAC) + (TIAC) =**	$ 34,247,220

Cost Effectiveness Summary

TOTAL TONS SO_2 AVOIDED PER YEAR	=	7.1
COST EFFECTIVENESS ($ PER TON AVOIDED)	**(TAC)/(TPY) =**	$ 4,844,020

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	20	years

Table 5-7. Annualized Costs for ULSD on the Diesel-fired Emergency Generator Engine (EU ID 7)

Shaded cells indicate user inputs

Project: GVEA North Pole - $PM_{2.5}$ BACT Analysis (EU ID 7 - Generac Gen Set Engine)

Prepared By:
Checked By:
Rev:

Annualized Costs

	DIRECT ANNUAL COSTS	QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1)	Operating & Maintenance Costs		%			$ -	$ -
(2)	Repair & Replacement Costs		%			$ -	$ -
(3)	Maintenance Materials		LOT		excluded in this estimate		
(4)	Utilities						
	(a) ULSD Costs:	1,664	GAL	0.2668	$ 444		$ 444
	Total Direct Annual Costs (TDAC)					TDAC =	$ 444
	INDIRECT ANNUAL COSTS						
(5)	Overhead		%		excluded in this estimate	$ -	$ -
(6)	Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
	Capital Recovery Factor [see inputs below]	0.0944					
(7)	Capital Recovery					CRF * TCI =	$ -
	Total Indirect Annual Costs (TIAC)					TIAC =	$ -
	TOTAL ANNUALIZED COSTS (TAC)					TAC = (TDAC) + (TIAC) =	$ 444

Cost Effectiveness Summary

TOTAL TONS SO_2 AVOIDED PER YEAR	=	0.00985
COST EFFECTIVENESS ($ PER TON AVOIDED)	(TAC)/(TPY) =	$ 45,072

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	20	years

Table 5-8. GVEA North Pole Facility - SO_2 BACT Cost Effectiveness

Summary[1] for Each Emission Unit Based on PTE

Control Technology Option	SO2 Emissions (tpy)	Total Installed Capital ($)	Total Annualized Cost ($/year)	Annual O&M Cost ($/year)	Cost Effectiveness ($/ton SO2 removed)
Simple Cycle Gas Turbine (EU ID 1)					
ULSD (0.0015 wt. pct. S)	4	$10,875,319	$20,661,330	$19,199,764	$13,942
No. 1 HSD (0.100 wt. pct. S)	297	~	$226,412	$226,412	$1,904
Good Combustion Practices (0.50 wt. pct. S) (existing)	1,486	~	~	~	~
Simple Cycle Gas Turbine (EU ID 2)					
Limited Operation + ULSD (0.0015 wt. pct. S)	4	$10,875,319	$18,978,063	$17,516,497	$14,037
Limited Operations + No. 1 HSD (0.100 wt. pct. S)	271	~	$206,562	$206,562	$1,904
Good Combustion Practices (0.50 wt. pct. S) (existing)	1,356	~	~	~	~
Combined Cycle Gas Turbines (EU IDs 5 and 6)					
ULSD (0.0015 wt. pct. S)	3	~	$34,247,220	~	$4,844,020
LSR/Naphtha (0.0050 wt. pct. S) + Good Combustion Practices (existing)	10	~	~	~	~
Emergency Generator Engine (EU ID 7)					
ULSD (0.0015 wt. pct. S) + Limited Operation	0.0002	~	$444	~	$45,072
Limited Operation (0.1 wt. pct. S) (existing)	0.01	~	~	~	~
Propane Fired Boilers (EU IDs 11 and 12)					
Low Sulfur Fuel (propane) (existing)	0	~	~	~	~

[1] All emission costs are on a per emission unit basis.

Table 5-9. GVEA North Pole Facility - Proposed SO_2 BACT and Associated Emission Rate for Each Emission Unit

ID	Description		Description	Emission Rate[1]
1, 2	Simple Cycle Gas Turbine	Fuel Oil	Good Combustion Practices (existing) + No. 1 HSD on air quality curtailment days	500 ppm S in fuel
5, 6	Combined Cycle Gas Turbine	LSR	LSR/Naphtha (existing)	50 ppm S in fuel
7	Emergency Generator Engine	Fuel Oil	Good Combustion Practices (existing)	500 ppm S in fuel
11, 12	Boiler	Propane	Low Sulfur Fuel - Propane (existing)	0.0012 lb/kgal

[1] Emissions are on a per emission unit basis.

Table 5-10. Capital Cost for New ULSD Storage Based on Maximum Fuel Use and Actual Fuel Use

	North Pole EUs 1 and 2 Maximum Fuel Use	Zehnder EUs 1 and 2 Maximum Fuel Use	North Pole EUs 1 and 2 Actual Fuel Use	Zehnder EUs 1 and 2 Actual Fuel Use
Capital Cost Estimate	$30,425,000		$21,050,000	
Heat Input, MMBtu/day (combined for each set of combustion turbines)	32,256	12,864	32,256	12,864
Percentage of Heat Input	71.5%	28.5%	71.5%	28.5%
Capital Cost (apportioned based on heat input ratio)	$ 21,750,638	$ 8,674,362	$ 15,048,511	$ 6,001,489
Capital Cost (apportioned per combustion turbine)	$ 10,875,319	$ 4,337,181	$ 7,524,255	$ 3,000,745
Capital Recovery (per combustion turbine)	$ 1,026,553	$ 409,399	$ 710,236	$ 283,249
Administrative Charges, Property Taxes, Insurance (per combustion turbine)	$ 435,013	$ 173,487	$ 300,970	$ 120,030
Total Annual Indirect Cost (per combustion turbine)	**$ 1,461,566**	**$ 582,886**	**$ 1,011,207**	**$ 403,279**

Capital recovery factor 0.0944

Data Inputs for Capital Recovery Factor:

Annual Interest Rate (EPA OAQPS Control Cost Manual) 7.00 pct.

Project Life (EPA OAQPS Control Cost Manual) 20 years

Administrative Charges, Property Taxes Insurance (percentage of total capital cost) 4.00%

Capital cost estimate for 1.27 million gallons of storage capacity.

GVEA
Alternative BACT
November 2018

Attachment 5b
Updated Cost Effectiveness Tables Zehnder

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Table 5-1. GVEA - Zehnder Facility - Summary of Available SO_2 Emission Control Technologies

Emission Unit		Available Emission Control Technology
ID	Description	
1, 2	Simple Cycle Gas Turbine	ULSD
		Low Sulfur Fuel
		Good Combustion Practices
3, 4	Diesel-fired Emergency Generator Engine	ULSD
		Low Sulfur Fuel
		Limited Operations
		Good Combustion Practices
10, 11	Diesel-fired Boiler	ULSD
		Low Sulfur Fuel
		Good Combustion Practices

Table 5-2. GVEA - Zehnder Facility - Summary of Technically Feasible SO_2 Emission Control Technologies

Emission Unit		Emission Control Technology
ID	Description	
1,2	Simple Cycle Combustion Gas Turbine	ULSD
		Low Sulfur Fuel
		Good Combustion Practices
3, 4	Diesel-fired Emergency Generator Engine	ULSD
		Low Sulfur Fuel
		Limited Operation
		Good Combustion Practices
10, 11	Diesel-fired Boiler	ULSD
		Low Sulfur Fuel
		Good Combustion Practices

Table 5-3. GVEA - Zehnder Facility - Ranking of Technically Feasible SO_2 Emission Control Technology

Emission Unit		Control Technology Used	Control Efficiency (pct)[2]	SO_2 Emissions Per Unit (tpy)	SO_2 Emissions Reduction (tpy)
ID	Description				
1, 2[1]	Simple Cycle Combustion Gas Turbines	ULSD Fuel (0.0015 wt. pct. S)	99.7	1.8	578.2
		Low-Sulfur Fuel (0.05 wt. pct. S)	89.8	59.3	520.7
		Good Combustion Practices (0.5 wt. pct. S) (existing)	0	580	0
3, 4[1]	Diesel-fired Emergency Generator Engines	ULSD Fuel (0.0015 wt. pct. S)	99.7	0.01	3.7
		Low-Sulfur Fuel (0.05 wt. pct. S)	90.0	0.37	3.3
		Limited Operation and Good Combustion Practices (0.5 wt. pct. S) (existing)	0	3.7	0
10, 11[1]	Diesel-fired Boilers	ULSD Fuel (0.0015 wt. pct. S)	99.7	0.012	3.8
		Low-Sulfur Fuel (0.05 wt. pct. S)	90.0	0.39	3.5
		Good Combustion Practices (0.5 wt. pct. S) (existing)	0	3.9	0

Note:

[1] Combined SO_2 emissions from EU IDs 1 through 4, 10, and 11 are limited to 580 tpy on a 12-month rolling basis per Permit AQ0109TVP03 Condition 9. Each emission unit can operate individually up to the potential emissions listed in this table. The fuel sulfur content is limited to 1.0 wt. pct. for EU IDs 1 through 4, per Permit AQ0109TVP03, Condition 10. However, No. 1 and No. 2 fuel oil (by specification) can have a maximum sulfur content of 0.5 wt. pct., so 0.5 percent fuel sulfur content is used as the baseline for each emission unit.

[2] The use of low-sulfur fuel and ULSD both result in the 580 tpy SO_2 limit being unncessary. For each emission unit, the control efficiencies are based on the emission reduction between the existing PTE and the PTE that would result due to the use of lower sulfur fuel.

Table 5-4. Annualized Costs for ULSD Combustion in the Diesel-fired Simple Cycle Gas Turbines (EU ID 1 and 2)

Shaded cells indicate user inputs

Cost Effectiveness Determination - ULSD Fuel Switch - No Additional Tank Storage

Project: GVEA Zhender - SO_2 BACT Analysis (EU ID 1 and 2 - Frame 5 CTs, cost per turbine)

Date:
Prepared By:
Checked By:
Rev:

Annualized Costs

DIRECT ANNUAL COSTS		QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1)	Operating & Maintenance Costs		%			$ -	$ -
(2)	Repair & Replacement Costs		%			$ -	$ -
(3)	Maintenance Materials		LOT				
(4)	Utilities						
	(a) ULSD Costs:	18,059,076.92	GAL	0.424	$ 7,657,049		$ 7,657,049
Total Direct Annual Costs (TDAC)						TDAC =	$ 7,657,049
INDIRECT ANNUAL COSTS							
(5)	Overhead		%			$ -	$ -
(6)	Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
	Capital Recovery Factor [see inputs below]	0.0944					
(7)	Capital Recovery					CRF * TCI =	$ -
Total Indirect Annual Costs (TIAC) (refer to Table 5-10)						TIAC =	$ 582,886
TOTAL ANNUALIZED COSTS (TAC)						TAC = (TDAC) + (TIAC) =	$ 8,239,935

Cost Effectiveness Summary

TOTAL TONS SO2 AVOIDED PER YEAR	=	578
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON PTE)	(TAC)/(TPY) =	$ 14,250
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON ACTUAL HISTORIC RUN TIMES, AVOIDING 51.9 TONS PER YEAR)[1]	(TAC)/(TPY) =	$ 20,734
COST EFFECTIVENESS ($ PER TON PM AVOIDED BASED ON 6 TONS SO_2 AVOIDED = 1 TON PM AVOIDED)[2]	(TAC)/(TPY) =	$ 124,401

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	20	years

[1] Annual average run hours of 770 for EU IDs 1 and 2, see Table 5-9. 700 hours equates to 1,587,385 gallons of fuel, a TDAC of $423,514 and a TAC of $970,728. The capital cost of bulk fuel

[2] Alaska Department of Environmental Conservation, Amendments to State Air Quality Control Plan Vol. III: Appendix III.D.5.7, page 52. In reference to fuel oil emissions, "Ambient sampling and

Table 5-5. Annualized Costs for ULSD Combustion in the Diesel-fired Engines (EU ID 3 and 4)

Shaded cells indicate user inputs

Cost Effectiveness Determination - ULSD Fuel Switch - No Additional Tank Storage

Project: GVEA Zhender - SO_2 BACT Analysis (EU ID 3 and 4 - General Motors Gen Set Engines, cost per engine)

Date:
Prepared By:
Checked By:
Rev:

Annualized Costs

	DIRECT ANNUAL COSTS	QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1)	Operating & Maintenance Costs		%			$ -	$ -
(2)	Repair & Replacement Costs		%			$ -	$ -
(3)	Maintenance Materials		LOT				
(4)	Utilities						
	(a) ULSD Costs:	107,692.31	GAL	0.2668	$ 28,732		$ 28,732
	Total Direct Annual Costs (TDAC)					**TDAC =**	$ 28,732
	INDIRECT ANNUAL COSTS						
(5)	Overhead		%			$ -	$ -
(6)	Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
	Capital Recovery Factor [see inputs below]	0.1424					
(7)	Capital Recovery					**CRF * TCI =**	$ -
	Total Indirect Annual Costs (TIAC)		**Not applicable**			**TIAC =**	$ -
	TOTAL ANNUALIZED COSTS (TAC)					**TAC = (TDAC) + (TIAC) =**	$ 28,732

Cost Effectiveness Summary

TOTAL TONS SO2 AVOIDED PER YEAR	= 3.7
COST EFFECTIVENESS ($ PER TON AVOIDED)	**(TAC)/(TPY) =** $ 7,768

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	10	years

Table 5-6 Annualized Costs for ULSD Combustion in the Diesel-fired Boilers (EU ID 10 and 11)

Shaded cells indicate user inputs

Cost Effectiveness Determination - ULSD Fuel Switch - No Additional Tank Storage

Project: GVEA Zhender - SO_2 BACT Analysis (EU ID 10 and 11 - Weil McLain Boilers, cost per boiler)

Date:
Prepared By:
Checked By:
Rev:

Annualized Costs

DIRECT ANNUAL COSTS		QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1)	Operating & Maintenance Costs		%			$ -	$ -
(2)	Repair & Replacement Costs		%			$ -	$ -
(3)	Maintenance Materials		LOT				
(4)	Utilities						
	(a) ULSD Costs:	114,553.85	GAL	0.2668	$ 30,563		$ 30,563
Total Direct Annual Costs (TDAC)						TDAC =	$ 30,563
INDIRECT ANNUAL COSTS							
(5)	Overhead		%			$ -	$ -
(6)	Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
	Capital Recovery Factor [see inputs below]	0.1424					
(7)	Capital Recovery					CRF * TCI =	$ -
Total Indirect Annual Costs (TIAC)			Not applicable			TIAC =	$ -
TOTAL ANNUALIZED COSTS (TAC)						TAC = (TDAC) + (TIAC) =	$ 30,563

Cost Effectiveness Summary

TOTAL TONS SO2 AVOIDED PER YEAR	=	3.8
COST EFFECTIVENESS ($ PER TON AVOIDED)	(TAC)/(TPY) =	$ 7,946

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	10	years

Table 5-7. GVEA - Zehnder Facility - SO_2 BACT Cost Effectiveness Summary for Each Emission Unit

Emission Control Technology	SO_2 Emissions (tpy)	Total Installed Capital ($)	Total Annualized Cost ($/year)	Annual O&M Cost ($/year)	Cost Effectiveness ($/ton SO_2 removed)
Diesel-fired Simple Cycle Gas Turbines (EU IDs 1 and 2, per turbine)					
ULSD Fuel (0.0015 wt. pct. S)	1.8	$4,337,181	$8,239,935	$7,657,049	$14,250
Good Combustion Practices (0.5 wt. pct. S) (existing)	580	~	~	~	~
Emergency Generator Engines (EU IDs 3 and 4, per engine)					
ULSD Fuel (0.0015 wt. pct. S)	0.01	~	$28,732	$28,732	$7,768
Limited Operation and Good Combustion Practices (0.5 wt. pct. S) (existing)	3.71	~	~	~	~
Diesel-fired Boilers (EU IDs 10 and 11, per boiler)					
ULSD Fuel (0.0015 wt. pct. S)	0.01	~	$30,563	$30,563	$7,946
Good Combustion Practices (0.5 wt. pct. S) (existing)	3.9	~	~	~	~

Note:
All costs are on a per unit basis.

Table 5-8. GVEA - Zehnder Facility - Proposed SO_2 BACT and Associated Emission Rate for Each Emission Unit

Emission Unit		Fuel	SO_2 BACT	
ID	Description		Description	Sulfur Content of Fuel
1, 2	Simple Cycle Gas Turbines	Fuel Oil	Fuel Oil and Good Combustion Practices (existing) - Refer to Table 5-9	0.5 wt. pct. S
3, 4	Emergency Generator Engines	Diesel	Fuel Oil and Good Combustion Practices (existing)	0.5 wt. pct. S
10, 11	Boilers	Diesel	ULSD	0.0015 wt. pct. S

Note:
[1] Emissions are on a per unit basis.

Table 5-9. GVEA - Zehnder Facility - SO_2 BACT Analysis for EU IDs 1 and 2 Based on Actual Operations

	SO_2 BACT Analysis Based on Potential Emissions	SO_2 BACT Analysis Based on Actual (Historical) Operations
Operating Basis	8,760 hr/yr	770 hr/yr
Emissions (EU 1 or EU 2)	580.0 tpy	52.1 tpy
Good combustion practices, 0.5 wt. pct. S (existing)		
PTE	580.0 tpy	52.1 tpy
PTE reduction	0.0 tpy	0.0 tpy
Cost effectiveness	N/A	N/A
ULSD Fuel (0.0015 wt. pct. S)		
PTE	1.8 tpy	0.2 tpy
PTE reduction	578.2 tpy	51.9 tpy
Total Direct annual Costs (TDAC)	$ 7,657,049 (Table 5-4)	$ 673,051 [1]
Total Indirect Annual Costs (TIAC)	$ 582,886 (Table 5-10)	$ 403,279 (Table 5-10)
Total annualized Costs (TAC = TDAC + TIAC)	$ 8,239,935	$ 1,076,330
Cost effectiveness	14,250 $/ton	20,734 $/ton

[1] Assuming 770 hours, 268 MMBtu/Hr, and .13 MMBtu/gal, for 1,587,385 gallons, and the fuel costs shown in Table 5-4)

Notes:

1. Historical Operating Hours

Year	EU 1	EU 2	Total
2007	267	529	797
2008	745	57	802
2009	**833**	408	1,241
2010	527	1,012	**1,539**
2011	756	509	1,265
2012	440	635	1,075
2013	226	936	1,162
2014	139	1,068	1,207
2015	339	991	1,330
2016	93	**1,137**	1,230

*2016 is not representative of typical use because EU 1 has been down waiting for a rebuild.

*Maximum annual operating hours for each turbine and total are shown in bold.

*The basis for this analysis is half of the total hours from 2010 for each turbine (770 hr/yr).

2. Basis for Emissions Calculations

SO_2 Emission Factor for EUs 1 and 2

Fuel with 0.5 wt. pct. S content	0.51	lb/MMBtu (AP-42 Table 3.1-2a)
Fuel with 0.05 wt. pct. S content	0.051	lb/MMBtu (AP-42 Table 3.1-2a)
Fuel with 0.015 wt. pct. S content	0.015	lb/MMBtu (AP-42 Table 3.1-2a)
Heat input capacity for EUs 1 and 2	268	MMBtu/hr

Total Annual Costs

Emission Control Technology	Control Efficiency (pct) from Table 5-3
ULSD Fuel (0.0015 wt. pct. S)	99.7
Good Combustion Practices (existing)	0

Table 5-10. Capital Cost for New ULSD Storage Based on PTE Maximum Fuel Use and Historic Actual Use

	North Pole EUs 1 and 2 Maximum Fuel Use	Zehnder EUs 1 and 2 Maximum Fuel Use	North Pole EUs 1 and 2 Actual Fuel Use	Zehnder EUs 1 and 2 Actual Fuel Use
Capital Cost Estimate	$30,425,000		$21,050,000	
Heat Input, MMBtu/day (combined for each set of combustion turbines)	32,256	12,864	32,256	12,864
Percentage of Heat Input	71.5%	28.5%	71.5%	28.5%
Capital Cost (apportioned based on heat input ratio)	$ 21,750,638	$ 8,674,362	$ 15,048,511	$ 6,001,489
Capital Cost (apportioned per combustion turbine)	$ 10,875,319	$ 4,337,181	$ 7,524,255	$ 3,000,745
Capital Recovery (per combustion turbine)	$ 1,026,553	$ 409,399	$ 710,236	$ 283,249
Administrative Charges, Property Taxes, Insurance (per combustion turbine)	$ 435,013	$ 173,487	$ 300,970	$ 120,030
Total Annual Indirect Cost (per combustion turbine)	**$ 1,461,566**	**$ 582,886**	**$ 1,011,207**	**$ 403,279**

Capital recovery factor	0.0944	

Data Inputs for Capital Recovery Factor:

Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	pct.
Project Life (EPA OAQPS Control Cost Manual)	20	years
Administrative Charges, Property Taxes Insurance (percentage of total capital cost)	4.00%	

Table E-1a. Summary of Identified SO_2 Control Technology - Liquid Fuel-Fired Simple Cycle Turbines > 25 MW (RBLC 15.190)

Pollutant	Control Technology Used	Number of RBLC Entries (11 Total)
SO_2	Low Sulfur Fuel	7
	None	4

Note: Data is based on a RBLC review from January 1, 2005 through September 15, 2015.

Table E-1b. Summary of Identified SO_2 Control Technology - Large Diesel Engines > 500 hp (RBLC 17.110)

Pollutant	Control Technology Used	Number of RBLC Entries (30 Total)
SO_2	Low-Sulfur Fuel	13
	ULSD Fuel	7
	None	3
	Good Combustion Practices	5
	NSPS Standards	2

Note: Data is based on a RBLC review from January 1, 2005 through September 15, 2015.

Table E-1c. Summary of Identified SO_2 Control Technology - Diesel-Fired Commercial/Institutional Boilers <100 MMBtu/hr (RBLC 13.220)

Pollutant	Control Technology Used	Number of RBLC Entries (6 Total)
SO_2	Low Sulfur Fuel	2
	Low Sulfur Fuel + Good Combustion Practices	2
	Wet or Dry Scrubber + Good Combustion Practices	1
	None	1

Note: Data is based on a RBLC review from January 1, 2005 through September 15, 2015.

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Alternative BACT
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Attachment 6
Tables 5-4a and 5-5a, North Pole EU ID 1 and 2 Cost Effectiveness with selective use of No. 1 HSD

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Table 5-5b. Annualized Costs for No. 1 HSD on the Diesel-fired Simple Cycle Gas Turbine (EU ID 2)

Shaded cells indicate user inputs

Project: GVEA North Pole - $PM_{2.5}$ BACT Analysis (EU ID 2 - GE Frame 7 CT)

Prepared By:
Checked By:
Rev:

Annualized Costs

DIRECT ANNUAL COSTS		QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1)	Operating & Maintenance Costs		%			$ -	$ -
(2)	Repair & Replacement Costs		%			$ -	$ -
(3)	Maintenance Materials		LOT		excluded in this estimate		
(4)	Utilities			10%	Estimated time running No. 1		
	(a) No 1 Costs:	41,312,492	GAL	0.05	$ 206,562		$ 206,562
Total Direct Annual Costs (TDAC)						TDAC =	$ 206,562
INDIRECT ANNUAL COSTS							
(5)	Overhead		%		excluded in this estimate	$ -	$ -
(6)	Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
	Capital Recovery Factor [see inputs below]	0.0944					
(7)	Capital Recovery					CRF * TCI =	$ -
Total Indirect Annual Costs (TIAC)						TIAC =	$ -
TOTAL ANNUALIZED COSTS (TAC)						TAC = (TDAC) + (TIAC) =	$ 206,562

Cost Effectiveness Summary

TOTAL TONS SO_2 AVOIDED PER YEAR [1]	=	108
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON PTE) (TAC)/(TPY) =	$	1,904

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	20	years

[1] Assuming PTE and running No. 1 HSD 10% of the days. Running No. 1 on curtailment days.

Table 5-4a. Annualized Costs for No. 1 HSD on the Diesel-fired Simple Cycle Gas Turbine (EU ID 1)

Shaded cells indicate user inputs

Project: GVEA North Pole - $PM_{2.5}$ BACT Analysis (EU ID 1 - GE Frame 7 CT)

Prepared By:
Checked By:
Rev:

Annualized Costs

DIRECT ANNUAL COSTS	QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1) Operating & Maintenance Costs		%			$ -	$ -
(2) Repair & Replacement Costs		%			$ -	$ -
(3) Maintenance Materials		LOT		excluded in this estimate		
(4) Utilities			10%	Estimated time running No. 1		
(a) ULSD Costs:	45,282,462	GAL	0.05	$ 226,412		$ 226,412
Total Direct Annual Costs (TDAC)					**TDAC =**	$ 226,412
INDIRECT ANNUAL COSTS						
(5) Overhead		%		excluded in this estimate	$ -	$ -
(6) Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
Capital Recovery Factor [see inputs below]	0.0944					
(7) Capital Recovery					**CRF * TCI =**	$ -
Total Indirect Annual Costs (TIAC)					**TIAC =**	$ -
TOTAL ANNUALIZED COSTS (TAC)					**TAC = (TDAC) + (TIAC) =**	$ 226,412

Cost Effectiveness Summary

TOTAL TONS SO_2 AVOIDED PER YEAR	=	119
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON PTE)	**(TAC)/(TPY) =**	$ 1,904

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	20	years

[1] Assuming PTE and running No. 1 HSD 10% of the days. Running No. 1 on curtailment days.

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Attachment 7
Zehnder FY2019 Assessable Emissions Summary

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Table 1. FY2019 Assessable Emissions Summary
Golden Valley Electric Association - Zehnder Facility

Assessable Emissions - Tons Per Year							
Description	**NO_X**	**CO**	**PM_{10}**	**SO_2**	**VOC**	**HAPs**	**Total**
Assessable PTE	2,854	217	746	580	23	-	4,420

From Condition 30 and Table C of the SOB for AQ0109TVP03

Potential to Emit	**Regulated Air Pollutant Emissions (tons per year)** [1]					
	NO_X	**CO**	**PM_{10}**	**VOC**	**SO_2**	**HAP**
Significant	70.8	0.3	1.0	0.0	30.1	
Insignificant	0.2	0.1	0.0	0.0	0.5	
Total Emissions	**71**	**0**	**1**	**0**	**31**	
Use Assessable PTE						**0**
Assessable Emission Subtotals	**71**	**0**	**1**	**0**	**31**	**0**
Fees Apply to Pollutant? [2]	**Yes**	**No**	**No**	**No**	**Yes**	**No**
2017 Actual Emissions	**102**					
Fee Estimate [3]	**$4,366**					

Notes:

[1] Regulated air pollutant calculations based on emission factors shown in accompanying spreadsheets.

[2] Fees paid on each pollutant emitted in quantities greater than 10 tpy per 18 AAC 50.410.

[3] A fee rate of $42.95 per ton applies in accordance with 18 AAC 50.410(b)(1).

[4] Actual emissions are not provided for HAPs because potential emissions for HAPs are less than 10 tpy. Actual emissions must be less than or equal to potential emissions, so actual emissions are also less than 10 tpy.

Table 2a. FY2019 Significant Emission Unit Summary
Golden Valley Electric Association - Zehnder Facility

Emission Unit			Fuel	2017 Actual	Maximum	2017 Actual
ID	Description	Make/Model	Type	Operation	Capacity	Fuel Consumption
1	Simple Cycle Gas Turbine	General Electric Frame 5 MS 5001-M	No. 1 Diesel	0.3 hr/yr	268 MMBtu/hr	90 gal/yr
			No. 2 Diesel			0 gal/yr
2	Simple Cycle Gas Turbine	General Electric Frame 5 MS 5001-M	No. 1 Diesel	1,133.4 hr/yr	268 MMBtu/hr	88,231 gal/yr
			No. 2 Diesel			1,072,989 gal/yr
3	Diesel Generator Engine	General Motors Electro-Motive Diesel 20-645E4	No. 2 Diesel	2.7 hr/yr	28 MMBtu/hr	588 gal/yr
4	Diesel Generator Engine	General Motors Electro-Motive Diesel 20-645E4	No. 2 Diesel		28 MMBtu/hr	
10	Boiler	Weil McLain H-688	No. 2 Diesel	755 hr/yr	1.7 MMBtu/hr	17,810 gal/yr
11	Boiler	Weil McLain H-688	No. 2 Diesel	755 hr/yr	1.7 MMBtu/hr	

Table 7. FY2019 Assessable Emission Calculations - Sulfur Dioxide (SO_2) Emissions
Golden Valley Electric Association - Zehnder Facility

Emission Unit		Fuel	Factor	Fuel	SO_2 Emission	2017 Actual	2017 Actual SO_2
ID	Description	Type	Reference	Sulfur Content [1,2]	Factor	Operation	Emissions
1	Simple Cycle Gas Turbine	No. 1 Diesel	Mass Balance	0.095 wt. pct. S	0.013 lb/gal	90 gal/yr	5.8E-04 tpy
		No. 2 Diesel	Mass Balance	0.381 wt. pct. S	0.054 lb/gal	0 gal/yr	0 tpy
2	Simple Cycle Gas Turbine	No. 1 Diesel	Mass Balance	0.095 wt. pct. S	0.013 lb/gal	88,231 gal/yr	0.57 tpy
		No. 2 Diesel	Mass Balance	0.381 wt. pct. S	0.054 lb/gal	1,072,989 gal/yr	29.03 tpy
3	Diesel Generator Engine	No. 2 Diesel	Mass Balance	0.381 wt. pct. S	0.054 lb/gal	588 gal/yr	1.6E-02 tpy
4	Diesel Generator Engine	No. 2 Diesel					
10	Boiler	No. 2 Diesel	Mass Balance	0.381 wt. pct. S	0.054 lb/gal	17,810 gal/yr	0.48 tpy
11	Boiler	No. 2 Diesel					
Significant Emission Units - 2017 Actual Emissions - SO_2							**30.1 tpy**
Insignificant Emission Units							
6	Fuel Oil Storage Tank	No. 2 Diesel	N/A	N/A	N/A	8,760 hr/yr	0 tpy
7	Fuel Oil Storage Tank	No. 2 Diesel	N/A	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank	No. 1 Diesel	N/A	N/A	N/A	8,760 hr/yr	0 tpy
8	Burnham Boiler	No. 2 Diesel	Mass Balance	0.381 wt. pct. S	0.054 lb/gal	6,215 gal/yr	1.7E-01 tpy
9	Burnham Boiler	No. 2 Diesel	Mass Balance	0.381 wt. pct. S	0.054 lb/gal	6,215 gal/yr	1.7E-01 tpy
N/A	Burnham Boiler - FE Building	Natural Gas	AP-42 Table 1.4-2	2,000 gr/10^6scf	0.6 lb/10^6scf	1,069,200 scf	3.2E-04 tpy
N/A	Burnham Boiler - FE Building	Natural Gas					
N/A	Lean Burn Inc. CB 2800 Overhead Shop Heater	Waste Oil	Mass Balance	0.124 wt. pct. S	0.018 lb/gal	0 gal/yr	0 tpy
N/A	Energy Logic EL-340H Heater	Waste Oil	Mass Balance	0.124 wt. pct. S	0.018 lb/gal	1,238 gal/yr	1.1E-02 tpy
N/A	Metzger Machine Corp. Boiler	No. 2 Diesel	Mass Balance	0.381 wt. pct. S	0.054 lb/gal	5,808 gal/yr	1.6E-01 tpy
N/A	Energy Logic EL-200H Heater	Waste Oil - Transformer	Mass Balance	0.121 wt. pct. S	0.017 lb/gal	1,764 gal/yr	1.5E-02 tpy
N/A	Energy Logic EL-200H Heater	Waste Oil - Transformer	Mass Balance	0.121 wt. pct. S	0.017 lb/gal	1,383 gal/yr	1.2E-02 tpy
N/A	Energy Logic EL-350H Heater	Waste Oil - Transformer	Mass Balance	0.121 wt. pct. S	0.017 lb/gal	0 gal/yr	0 tpy
Insignificant Emission Units - 2017 Actual Emissions - SO_2							**0.53 tpy**
2017 Actual Emissions - SO_2							**30.6 tpy**

Sample Calculations: [3]

Molar mass ratio is 32 lb S/mol : 64 lb SO_2/mol

Stoichiometry: 1 mol S = 1 mol SO_2

Mass Balance Emission Factor, lb/gal = (Molar mass ratio, 2 lb SO_2:1 lb S) x (weight % S in fuel) x (density of fuel, lb/gal) / 100%

Emissions, tpy= (Emission factor, lb/gal) x (Fuel Use gal/yr) / (2,000 lb/ton)

Boiler Emissions, tpy= (Emission factor, lb/10^6scf) / (Conversion 1,000,000 scf/10^6scf) x (Fuel Consumption, scf) / (2,000 lb/ton)

Notes:

1 For diesel fuels, fuel sulfur content is the average of the monthly maximum fuel sulfur content values for calendar year 2017.

2 For waste oil and waste transformer oil, fuel sulfur content was determined by testing conducted in December 2016.

[3] Diesel fuel density is equal 6.8 lb/gal for No. 1 Diesel and 7.1 lb/gal for No. 2 Diesel per plant report.

GVEA
Alternative BACT
November 2018

Attachment 8
House Freeze Up Time Estimates

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? HOUSE COOL DOWN MODEL

If more than twenty five (25) house/services involved in outage, Inside Temperature @ T(0) = 70 °F

Notify FNSB Emergency Services mCp = 2.5 kWh/°F = 8532.5 BTU/°F

to trigger Red Cross Assistance k = 0.16 kW/°F = 546.1 BTU/Hr-°F

	Time	Inside Temperature of House following loss of heat source												
	Hours	-80 F	-70 F	-60 F	-50 F	-40 F	-30 F	-20 F	-10 F	0 F	10 F	20 F	30 F	40 F
	0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
	1	60.7	61.3	61.9	62.6	63.2	63.8	64.4	65.0	65.7	66.3	66.9	67.5	68.1
Notification	2	52.0	53.2	54.4	55.6	56.8	58.0	59.2	60.4	61.6	62.8	64.0	65.2	66.4
Time	3	43.8	45.5	47.3	49.0	50.8	52.5	54.3	56.0	57.8	59.5	61.3	63.0	64.8
0% Freeze	4	36.1	38.4	40.6	42.9	45.2	47.4	49.7	51.9	54.2	56.4	58.7	61.0	63.2
	5	28.9	31.7	34.4	37.1	39.9	42.6	45.4	48.1	50.8	53.6	56.3	59.0	61.8
	6	22.2	25.4	28.5	31.7	34.9	38.1	41.3	44.5	47.7	50.9	54.1	57.2	60.4
	7	15.8	19.4	23.1	26.7	30.3	33.9	37.5	41.1	44.7	48.3	51.9	55.6	59.2
	8	9.9	13.9	17.9	21.9	25.9	29.9	33.9	37.9	42.0	46.0	50.0	54.0	58.0
Estimated	9	4.3	8.7	13.1	17.5	21.8	26.2	30.6	35.0	39.3	43.7	48.1	52.5	56.9
100% Freeze	10	-0.9	3.8	8.5	13.3	18.0	22.7	27.5	32.2	36.9	41.6	46.4	51.1	55.8
	11	-5.8	-0.8	4.3	9.4	14.4	19.5	24.5	29.6	34.6	39.7	44.7	49.8	54.8
	12	-10.4	-5.0	0.3	5.7	11.0	16.4	21.8	27.1	32.5	37.8	43.2	48.6	53.9
	13	-14.7	-9.1	-3.4	2.2	7.9	13.5	19.2	24.8	30.5	36.1	41.8	47.4	53.1
	14	-18.8	-12.9	-6.9	-1.0	4.9	10.8	16.7	22.7	28.6	34.5	40.4	46.3	52.2
	15	-22.6	-16.4	-10.2	-4.1	2.1	8.3	14.5	20.6	26.8	33.0	39.1	45.3	51.5
	16	-26.1	-19.7	-13.3	-6.9	-0.5	5.9	12.3	18.7	25.1	31.5	38.0	44.4	50.8
	17	-29.5	-22.8	-16.2	-9.6	-2.9	3.7	10.3	17.0	23.6	30.2	36.8	43.5	50.1
	18	-32.6	-25.8	-18.9	-12.1	-5.2	1.6	8.4	15.3	22.1	29.0	35.8	42.6	49.5
	19	-35.5	-28.5	-21.5	-14.4	-7.4	-0.4	6.7	13.7	20.7	27.8	34.8	41.9	48.9
	20	-38.3	-31.1	-23.9	-16.6	-9.4	-2.2	5.0	12.2	19.5	26.7	33.9	41.1	48.3
	21	-40.9	-33.5	-26.1	-18.7	-11.3	-3.9	3.5	10.9	18.3	25.6	33.0	40.4	47.8
	22	-43.3	-35.8	-28.2	-20.6	-13.1	-5.5	2.0	9.6	17.1	24.7	32.2	39.8	47.3
	23	-45.6	-37.9	-30.2	-22.5	-14.8	-7.1	0.7	8.4	16.1	23.8	31.5	39.2	46.9
	24	-47.7	-39.9	-32.0	-24.2	-16.3	-8.5	-0.6	7.2	15.1	22.9	30.8	38.6	46.5
	25	-49.7	-41.7	-33.8	-25.8	-17.8	-9.8	-1.8	6.2	14.1	22.1	30.1	38.1	46.1
	26	-51.6	-43.5	-35.4	-27.3	-19.2	-11.1	-3.0	5.2	13.3	21.4	29.5	37.6	45.7
	27	-53.4	-45.1	-36.9	-28.7	-20.5	-12.2	-4.0	4.2	12.4	20.7	28.9	37.1	45.3

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Chena Power Plant Aurora Energy, LLC

- DEC Best Available Control Technology (BACT) for Chena Power Plant – Aurora Energy, LLC
- DEC letter to Mr. Fish (Aurora) for the Request for Additional Information of the BACT Technical Memorandum from Aurora Energy, LLC for the Chena Power Plant by December 22, 2017 (dated November 16, 2017)
- DEC Request for Additional Information Aurora Energy LLC – Chena Power Plant BACT Analysis Review, March 2017 (dated November 16, 2017)
- Aurora BACT Analysis Review Comments Reports to EPA March 2017 (dated November 15, 2017)
- DEC letter to Mr. Fish (Aurora) on Voluntary BACT analysis for Chena (dated April 24, 2015)
- Aurora's response to response to DEC's Request for Additional Information for the BACT Technical Memorandum from Aurora Energy, LLC (Aurora) for Chena Power Plant by December 22, 2017 (dated December 22, 2017)
- Addendum to Best Available Control Technology Analysis by Chena Power Plant Fairbanks, Alaska December 2017
- DEC's second request to Mr. Fish (Aurora) for the Request of Additional Information for the BACT Technical Memorandum from Aurora Energy, LLC for the Chena Power Plant by November 1, 2018 (dated September 13, 2018)
- DEC's Request for Additional Information Aurora Energy LLC. – Chena Power Plant BACT Analysis Review March 2017 (dated September 10, 2018)
- EPA comments on DEC's Preliminary Draft Serious SIP Development for the Fairbanks nonattainment area
- Aurora's response to DEC's Request for Additional Information for the BACT Technical Memorandum from Aurora Energy, LLC (Aurora) for Chena (dated November 1, 2018)
- Stanley Consultants, Inc. letter to Aurora – Qualitative Cost Comparison of Circulating Dry Scrubber Technology Versus Spray Dryer Absorbers
- BACT Process Systems, Inc. Letter to Aurora – DSI for Aurora Energy/BACT Proposal No. 1899-R1
- United Facilities Criteria (UFC) – Department of Defense (DoD) Facilities Pricing Guide
- EPA Office of Air and Radiation – Small Industrial-Commercial-Institutional Steam Generating Units – Background Information for Promulgated Standards
- NESCAUM (November 2008) - Applicability and Feasibility of NOX, SO2, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers
- Aurora Proposed BACT Alternative November 19, 2018
- Appendix A - Economic Analysis Spreadsheets
- Appendix B – Economic Analysis Spreadsheets – V2
- Appendix C – Coal Analysis Summary
- Appendix D – Professional Memo
- Appendix E – Coal Sulfur Summary

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
Air Permits Program

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION
for
Chena Power Plant
Aurora Energy, LLC.

Prepared by: Aaron Simpson
Supervisor: James R. Plosay
Date: May 10, 2019

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Abbreviations/Acronyms

AAC .....Alaska Administrative Code
AAAQS .....Alaska Ambient Air Quality Standards
Department .....Alaska Department of Environmental Conservation
BACT .....Best Available Control Technology
CFB……Circulating Fluidized Bed
CFR. .....Code of Federal Regulations
Cyclones…….Mechanical Separators
DFP……Diesel Particulate Filter
DLN.....Dry Low NOx
DOC……..Diesel Oxidation Catalyst
EPA .....Environmental Protection Agency
ESP…….Electrostatic Precipitator
EU.....Emission Unit
FITR……..Fuel Injection Timing Retard
GCPs……..Good Combustion Practices
HAP.....Hazardous Air Pollutant
ITR…….Ignition Timing Retard
LEA……Low Excess Air
LNB……Low NOx Burners
MR&Rs .....Monitoring, Recording, and Reporting
NESHAPS .....National Emission Standards for Hazardous Air Pollutants
NSCR…….Non-Selective Catalytic Reduction
NSPS .....New Source Performance Standards
ORL.....Owner Requested Limit
PSD.....Prevention of Significant Deterioration
PTE.....Potential to Emit
RICE, ICE .....Reciprocating Internal Combustion Engine, Internal Combustion Engine
SCR .....Selective Catalytic Reduction
SIP .....Alaska State Implementation Plan
SNCR…….Selective Non-Catalytic Reduction
ULSD .....Ultra Low Sulfur Diesel

Units and Measures

gal/hr.....gallons per hour
g/kWh .....grams per kilowatt hour
g/hp-hr .....grams per horsepower hour
hr/day.....hours per day
hr/yr .....hours per year
hp.....horsepower
lb/hr .....pounds per hour
lb/MMBtu.....pounds per million British thermal units
lb/1000 gal.....pounds per 1,000 gallons
kW .....kilowatts
MMBtu/hr.....million British thermal units per hour
MMscf/hr.....million standard cubic feet per hour
ppmv.....parts per million by volume
tpy.....tons per year

Pollutants

CO .....Carbon Monoxide
HAP.....Hazardous Air Pollutant
NOx .....Oxides of Nitrogen
SO_2 .....Sulfur Dioxide
PM-2.5.....Particulate Matter with an aerodynamic diameter not exceeding 2.5 microns
PM-10.....Particulate Matter with an aerodynamic diameter not exceeding 10 microns

1. INTRODUCTION

Chena Power Plant is a stationary source owned by Aurora Energy, LLC (Aurora) which consists of four boilers. Emission Units (EUs) 4 through 6, also identified as Chena 1, 2, and 3, are coal-fired overfeed traveling grate stokers with a maximum steam production rating of 50,000 lbs/hr each. Maximum design power production is 5 megawatts (MW) each. EU 4 was installed in 1954, while EUs 5 and 6 were installed in 1952. EU 7, also identified as Chena 5, is a coal-fired, spreader stoker boiler with a maximum steam production rating of 200,000 lbs/hr and maximum power production rating of 20 MW. Chena 5 was installed in 1970. Maximum coal consumption is 284,557 tons of coal per year, based on the capacities of EUs 4 through 7. Coal receiving and storage (handling) facilities are located on the north bank of the Chena River, and consist of a rail car receiving station, enclosed coal crusher (receiving building), open storage piles, conveyors, and elevators. Coal is transported by conveyors over the Chena River to the Chena Power Plant, located just above the south bank. In the late 1980's, the coal handling system was renovated.

In a letter dated April 24, 2015, the Alaska Department of Environmental Conservation (Department) requested the stationary sources expected to be major stationary sources in the particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers (PM-2.5) serious nonattainment area perform a voluntary Best Available Control Technology (BACT) review in support of the state agency's required SIP submittal once the nonattainment area is re-classified as a Serious PM-2.5 nonattainment area. The designation of the area as "Serious" with regard to nonattainment of the 2006 24-hour PM-2.5 ambient air quality standards was published in Federal Register Vol. 82, No. 89, May 10, 2017, pages 21703-21706, with an effective date of June 9, 2017. [1]

This report addresses the significant emissions units (EUs) listed in Operating Permit No. AQ0315TVP03, Revision 1. This report provides the Department's review of the BACT analysis for oxides of nitrogen (NOx) and sulfur dioxide (SO_2) emissions, which are precursor pollutants that can form PM-2.5 in the atmosphere post combustion.

The following sections review Chena Power Plant's BACT analysis for technical accuracy and adherence to accepted engineering cost estimation practices.

2. BACT EVALUATION

A BACT analysis is an evaluation of all available control options for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts. 40 CFR 52.21(b)(12) defines BACT as a site-specific determination on a case-by-case basis. The Department's goal is to identify BACT for the permanent EUs at Chena Power Plant that emit NOx and SO_2, establish emission limits which represent BACT, and assess the level of monitoring, recordkeeping, and reporting (MR&Rs) necessary to ensure Chena Power Plant applies BACT for the EUs. The Department based the BACT review on the five-step top-down approach set forth in Federal Register Volume 61, Number 142, July 23, 1996 (Environmental Protection Agency).

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)

Table **A** present the EUs subject to BACT review.

Table A: Emission Units Subject to BACT Review

EU	Emission Unit Name	Emission Unit Description	Rating/Size	Installation or Construction Date
4	Chena 1 Coal Fired Boiler	Full Stream Baghouse Exhaust	76 MMBtu/hr	1954
5	Chena 2 Coal Fired Boiler	Full Stream Baghouse Exhaust	76 MMBtu/hr	1952
6	Chena 3 Coal Fired Boiler	Full Stream Baghouse Exhaust	76 MMBtu/hr	1952
7	Chena 5 Coal Fired Boiler	Full Stream Baghouse Exhaust	269 MMBtu/hr	1970

Five-Step BACT Determinations
The following sections explain the steps used to determine BACT for NOx and SO_2 for the applicable equipment.

Step 1 Identify All Potentially Available Control Technologies
The Department identifies all available control technologies for the EUs and the pollutant under consideration. This includes technologies used throughout the world or emission reductions through the application of available control techniques, changes in process design, and/or operational limitations. To assist in identifying available controls, the Department reviews available controls listed on the Reasonably Available Control Technology (RACT), BACT, and Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC). The RBLC is an EPA database where permitting agencies nationwide post imposed BACT for PSD sources. It is usually the first stop for BACT research. In addition to the RBLC search, the Department used several search engines to look for emerging and tried technologies used to control NOx and SO_2 emissions from equipment similar to those listed in
Table **A**.

Step 2 Eliminate Technically Infeasible Control Technologies
The Department evaluates the technical feasibility of each control technology based on source specific factors in relation to each EU subject to BACT. Based on sound documentation and demonstration, the Department eliminates control technologies deemed technically infeasible due to physical, chemical, and engineering difficulties.

Step 3 Rank the Remaining Control Technologies by Control Effectiveness
The Department ranks the remaining control technologies in order of control effectiveness with the most effective at the top.

Step 4 Evaluate the Most Effective Controls and Document the Results as Necessary
The Department reviews the detailed information in the BACT analysis about the control efficiency, emission rate, emission reduction, cost, environmental, and energy impacts for each technology to decide the final level of control. The analysis must present an objective evaluation of both the beneficial and adverse energy, environmental, and economic impacts. A proposal to use the most effective option does not need to provide the detailed information for the less

effective options. If cost is not an issue, a cost analysis is not required. Cost effectiveness for a control option is defined as the total net annualized cost of control divided by the tons of pollutant removed per year. Annualized cost includes annualized equipment purchase, erection, electrical, piping, insulation, painting, site preparation, buildings, supervision, transportation, operation, maintenance, replacement parts, overhead, raw materials, utilities, engineering, start-up costs, financing costs, and other contingencies related to the control option. Sections 3 and 4 present the Department's BACT Determinations for NOx and SO_2.

Step 5 Select BACT

The Department selects the most effective control option not eliminated in Step 4 as BACT for the pollutant and EU under review and lists the final BACT requirements determined for each EU in this step. A project may achieve emission reductions through the application of available technologies, changes in process design, and/or operational limitations. The Department reviewed Aurora's BACT analysis and made BACT determinations for NOx and SO_2 for the Chena Power Plant. These BACT determinations are based on the information submitted by Aurora in their analysis, information from vendors, suppliers, sub-contractors, RBLC, and an exhaustive internet search.

3. BACT DETERMINATION FOR NOx

The NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC is planning to submit with the Serious SIP a final precursor demonstration as justification not to require NOx controls. Please see the precursor demonstration for NOx posted at http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip-development. The PM2.5 NAAQS Final SIP Requirements Rule states if the state determines through a precursor demonstration that controls for a precursor gas are not needed for attaining the standard, then the controls identified as BACT/BACM or Most Stringent Measure for the precursor gas are not required to be implemented.[2] Final approval of the precursor demonstration is at the time of the Serious SIP approval.

Chena Power Plant has three existing 76 million British Thermal Units (MMBtu)/hr overfeed traveling grate stoker type boilers and one 269 MMBtu/hr spreader-stoker type boiler that burns coal to produce steam for stationary source-wide heating and power. The Department based its NOx assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by Golden Valley Electric Association (GVEA) for the North Pole Power Plant and Zehnder Facility, Aurora Energy, LLC (Aurora) for the Chena Power Plant, U.S. Army Corps of Engineers (US Army) for Fort Wainwright, and the University of Alaska Fairbanks (UAF) for the Fairbanks Campus Power Plant.

3.1 NOx BACT for the Industrial Coal-Fired Boilers

Possible NOx emission control technologies for coal fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.110

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf

for Coal Combustion in Industrial Size Boilers and Furnaces. The search results for coal-fired boilers are summarized in Table 3-1.

Table 3-1. RBLC Summary of NOx Control for Industrial Coal-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Selective Catalytic Reduction	9	0.05 – 0.08
Selective Non-Catalytic Reduction	18	0.07 – 0.36
Low NOx Burners	18	0.07 – 0.3
Overfire Air	8	0.07 – 0.3
Good Combustion Practices	2	0.1 – 0.6

RBLC Review
A review of similar units in the RBLC indicates selective catalytic reduction, selective non-catalytic reduction, low NOx burners, overfire air, and good combustion practices are the principle NOx control technologies installed on industrial coal-fired boilers. The lowest NOx emission rate in the RBLC is 0.05 lb/MMBtu.

Step 1- Identification of NOx Control Technologies for the Industrial Coal-Fired Boilers
From research, the Department identified the following technologies as available for control of NOx emissions from the industrial coal-fired boilers:

(a) Selective Catalytic Reduction (SCR)[3]
SCR is a post-combustion gas treatment technique for reducing nitric oxide (NO) and nitrogen dioxide (NO_2) in the boiler exhaust stream to molecular nitrogen (N_2), water, and oxygen (O_2). In the SCR process, aqueous or anhydrous ammonia (NH_3) is injected into the flue gas upstream of a catalyst bed. The catalyst lowers the activation energy of the NOx decomposition reaction. NOx and NH_3 combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental N_2 and water. Depending on the overall NH_3-to-NOx ratio, removal efficiencies are generally 80 to 90 percent. Challenges associated with using SCR on boilers include a narrow window of acceptable inlet and exhaust temperatures (500°F to 800°F), emission of NH_3 into the atmosphere (NH_3 slip) caused by non-stoichiometric reduction reaction, and disposal of depleted catalysts. The Department considers SCR a technically feasible control technology for the industrial coal-fired boilers.

(b) Selective Non-Catalytic Reduction (SNCR)[4]
SNCR involves the non-catalytic decomposition of NOx in the flue gas to N_2 and water using reducing agents such as urea or NH_3. The process utilizes a gas phase homogeneous reaction between NOx and the reducing agent within a specific temperature window. The reducing agent must be injected into the flue gas at a location in the unit that provides the optimum reaction temperature and residence time. The NH_3 process (trade name-Thermal DeNOx) requires a reaction temperature window of 1,600°F to 2,200°F. In the urea process (trade name–NO_xOUT), the optimum temperature ranges between 1,600°F and 2,100°F. Expected NOx removal efficiencies are typically

[3] https://www3.epa.gov/ttncatc1/dir1/fscr.pdf
[4] https://www3.epa.gov/ttncatc1/dir1/fsncr.pdf

between 40 to 62 percent, according to the RBLC, or between 30 and 50 percent reduction, according to the EPA fact sheet (EPA-452/F-03-031). The Department considers SNCR a technically feasible control technology for the industrial coal-fired boilers.

(c) Non-Selective Catalytic Reduction (NSCR)
NSCR simultaneously reduces NOx and oxidizes CO and hydrocarbons in the exhaust gas to N_2, carbon dioxide (CO_2), and water. The catalyst, usually a noble metal, causes the reducing gases in the exhaust stream (hydrogen, methane, and CO) to reduce both NO and NO_2 to N_2 at a temperature between 800°F and 1,200°F, below the expected temperature of the coal-fired boiler flue gas. NSCR requires a low excess O_2 concentration in the exhaust gas stream to be effective because the O_2 must be depleted before the reduction chemistry can proceed. NSCR is only effective with rich-burn gas-fired units that operate at all times with an air/fuel ratio controller at or close to stoichiometric conditions. Coal-fired boilers operate under conditions far more fuel-lean than required to support NSCR. The Department's research did not identify NSCR as a control technology used to control NOx emissions from large coal fired boilers installed at any facility after 2005. The Department does not consider NSCR a technically feasible control technology for the industrial coal-fired boilers.

(d) Low NOx Burners (LNBs)
Using LNBs can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature. Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 60% but under certain conditions, higher reductions are possible. Air staging or two-stage combustion, is generally described as the introduction of overfire air into the boiler or furnace. Overfire air is the injection of air above the main combustion zone. As indicated by EPA's AP-42, LNBs are applicable to tangential and wall-fired boilers of various sizes but are not applicable to other boiler types such as cyclone furnaces or stokers. The Department does not consider LNBs a technically feasible control technology for stoker type coal-fired boilers.

(e) Circulating Fluidized Bed (CFB)
In a fluidized bed combustor, fuel is introduced to a bed of either sorbent (limestone) or inert material (usually sand) that is fluidized by an upward flow of air. This upward air flow allows for better mixing of the gas and solids to create a better heat transfer and chemical reactions. Combustion takes place in the bed at a lower temperature than other boiler types which lowers the formation of thermally generated NOx. The Department does not consider CFB a technically feasible control technology to retrofit existing coal-fired boilers. For the purposes of this report, a control technology does not include passive control measures that act to prevent pollutants from forming or the use of combustion or other process design features or characteristics. The Department does not

consider CFB a technically feasible control technology to retrofit the existing coal-fired boilers.

(f) Low Excess Air (LEA)
Boiler operation with low excess air is considered an integral part of good combustion practices because this process can maximize the boiler efficiency while controlling the formation of NOx. Boilers operated with five to seven percent excess air typically have peak NOx formation from both peak combustion temperatures and chemical reactions. At both lower and higher excess air concentrations the formation of NOx is reduced. At higher levels of excess air, an increase in the formation of CO occurs. CO can increase exponentially at very high levels of excess air and the combustion efficiency is greatly reduced. As a result, the preference is to reduce excess air such that both NOx and CO generation is minimized and the boiler efficiency is optimized. Only one RLBC entry identified low excess air technology as a NOx control alternative for a mass-feed stoker designed boiler. Boilers are regularly designed to operate with low excess air as described in the previous LNB discussion. The Department considers LEA a technically feasible control technology for the industrial coal-fired boilers.

(g) Good Combustion Practices (GCPs)
GCPs typically include the following elements:

1. Sufficient residence time to complete combustion;
2. Providing and maintaining proper air/fuel ratio;
3. High temperatures and low oxygen levels in the primary combustion zone; and
4. High enough overall excess oxygen levels to complete combustion and maximize thermal efficiency.

Combustion efficiency is dependent on the gas residence time, the combustion temperature, and the amount of mixing in the combustion zone. GCPs are accomplished primarily through combustion chamber design as it relates to residence time, combustion temperature, air-to-fuel mixing, and excess oxygen levels. The Department considers GCPs a technically feasible control option for the coal-fired boilers.

(h) Fuel Switching
This evaluation considers retrofit of existing coal-fired boilers. It is assumed that use of another type of coal would not reduce NOx emissions. Therefore, the Department does not consider the use of an alternate fuel to be a technically feasible control technology for the industrial coal-fired boilers.

(i) Steam / Water Injection
Steam/water injection into the combustion zone reduces the firing temperature in the combustion chamber and has been traditionally associated with reducing NOx emissions from gas combustion turbines but not coal-fired boilers. In addition, steam/water has several disadvantages, including increases in carbon monoxide and un-burned hydrocarbon emissions and increased fuel consumption. Further, the Department found that steam or water injection is not listed in the EPA RBLC for use in any coal-fired boilers and it would be less efficient at controlling NOx emissions than SCR. Therefore,

the Department does not consider steam or water injection to be a technically feasible control option for the existing coal-fired boilers.

(j) Reburn
Reburn is a combustion hardware modification in which the NOx produced in the main combustion zone is reduced in a second combustion zone downstream. This technique involves withholding up to 40 percent (at full load) of the heat input to the main combustion zone and introducing that heat input above the top row of burners to create a reburn zone. Reburn fuel (natural gas, oil, or pulverized coal) is injected with either air or flue gas to create a fuel-rich zone that reduces the NOx created in the main combustion zone to nitrogen and water vapor. The fuel-rich combustion gases from the reburn zone are completely combusted by injecting overfire air above the reburn zone. Reburn may be applicable to many boiler types firing coal as the primary fuel, including tangential, wall-fired, and cyclone boilers. However, the application and effectiveness are site-specific because each boiler is originally designed to achieve specific steam conditions and capacity which may be altered due to reburn. Commercial experience is limited; however, this limited experience does indicate NOx reduction of 50 to 60 percent from uncontrolled levels may be achieved. Reburn combustion control would require significant changes to the design of the existing boilers. Therefore, the Department does not consider reburn to be a technically feasible control technology to retrofit the existing industrial coal-fired boilers.

Step 2 - Elimination of Technically Infeasible NOx Control Options for Coal-Fired Boilers
As explained in Step 1 of Section 3.1, the Department does not consider non-selective catalytic reduction, low NOx burners, circulating fluidized beds, fuel switching, steam/water injection, or reburn as technically feasible technologies to control NO_x emissions from existing industrial coal-fired boilers.

Step 3 - Ranking of Remaining NOx Control Technologies for Coal-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from the coal-fired boilers:

(a)	Selective Catalytic Reduction	(70% - 90% Control)
(b)	Selective Non-Catalytic Reduction	(30% - 50% Control)
(g)	Good Combustion Practices	(Less than 40% Control)
(f)	Low Excess Air	(10% - 20% Control)

Step 4 - Evaluate the Most Effective Controls

Aurora BACT Proposal

Aurora provided an economic analysis for the installation of SCR on all four boilers combined (EUs 4 through 7). Aurora also provided economic analyses for the installation of SNCR on the three 76 MMBtu/hr boilers (EUs 4 through 6), the 269 MMBtu/hr boiler (EU 7), and all four boilers combined (EUs 4 through 7). A summary of the analyses is shown in Table 3-2.

Table 3-2. Aurora Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR (EUs 4 – 7)	784	564	$73,069,750	$15,994,554	$28,347
SNCR (EUs 7)	342	103	$2,792,684	$784,066	$7,649
SNCR (EUs 4 – 6)	439	132	$4,906,782	$1,589,578	$12,059
SNCR (EUs 4 – 7)	781	234	$7,699,466	$2,373,645	$10,130

Aurora's economic analysis indicates the level of NOx reduction does not justify the use of SCR or SNCR for the coal-fired boilers based on the excessive cost per ton of NOx removed per year.

Aurora proposes the following as BACT for NOx emissions from the coal-fired boilers:

(a) NOx emissions from the operation of the coal-fired boilers will be controlled with existing combustion controls;

(b) NOx emissions from the coal-fired boilers will not exceed 0.36 lb/MMBtu; and

(c) Initial compliance with the proposed NOx emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

Department Evaluation of BACT for NOx Emissions from the Industrial Coal-Fired Boilers

The Department revised the cost analyses provided by Aurora for the installation of SCR and SNCR using the cost estimating procedures identified in EPA's May 2016 Air Pollution Control Cost Estimation Spreadsheets for Selective Catalytic Reduction[5] and Selective Non-Catalytic Reduction,[6] using the unrestricted potential to emit of the four coal-fired boilers, a baseline emission rate of 0.437 lb NOx/MMBtu,[7] a retrofit factor of 1.5 for projects requiring a difficult retrofit, a NOx removal efficiency of 90% and 50% for SCR and SNCR respectively, and a 20 year equipment life. A summary of the analysis is shown below:

Table 3-3. Department Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
SCR	940	846	$26,341,430	$3,403,675	$4,023
SNCR	940	470	$5,924,241	$1,046,952	$2,227
Capital Recovery Factor = 0.0837 (5.5% interest rate for a 20 year equipment life)					

The Department's economic analysis indicates the level of NOx reduction justifies the use of SCR or SNCR as BACT for the coal-fired boilers located in the Serious PM-2.5 nonattainment area.

[5] https://www3.epa.gov/ttn/ecas/docs/scr_cost_manual_spreadsheet_2016_vf.xlsm
[6] https://www3.epa.gov/ttn/ecas/docs/sncr_cost_manual_spreadsheet_2016_vf.xlsm
[7] Emission rate from most recent NOx and SO_2 source test accepted by the Department for permitting applicability, which occurred on November 19, 2011.

Step 5 - Selection of NOx BACT for the Industrial Coal-Fired Boilers
The Department's finding is that selective catalytic reduction and selective non-catalytic reduction are both economically and technically feasible control technologies for NOx. Since selective catalytic reduction has a higher control efficiency, it is selected as BACT to control NOx emissions from the industrial coal-fired boilers.

The Department's finding is that BACT for NOx emissions from the coal-fired boilers is as follows:

(a) NOx emissions from EUs 4 through 7 shall be controlled by operating and maintaining SCR at all times the units are in operation;

(b) NOx emissions from DU EUs 4 through 7 shall not exceed 0.05 lb/MMBtu averaged over a 3-hour period; and

(c) Initial compliance with the proposed NOx emission rate will be demonstrated by conducting a performance test to obtain an emission rate.

Table 3-4 lists the proposed NOx BACT determination for this facility along with those for other coal-fired boilers in the Serious PM-2.5 nonattainment area.

Table 3-4. Comparison of NOx BACT for Coal-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	6 Coal-Fired Boilers	1,380 MMBtu/hr	0.06 lb/MMBtu[8]	Selective Catalytic Reduction
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.02 lb/MMBtu[9]	Selective Catalytic Reduction
Chena	4 Coal-Fired Boilers	497 MMBtu/hr	0.05 lb/MMBtu[10]	Selective Catalytic Reduction

4. BACT DETERMINATION FOR SO_2

The Department based its SO_2 assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by GVEA for the North Pole Power Plant and Zehnder Facility, Aurora for the Chena Power Plant, US Army for Fort Wainwright, and UAF for the Combined Heat and Power Plant.

4.1 SO_2 BACT for the Industrial Coal-Fired Boilers

Possible SO_2 emission control technologies for coal-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.110, Coal Combustion in Industrial Size Boilers and Furnaces. The search results for the coal-fired boilers are summarized in Table 4-1.

[8] Calculated using a 90% NOx control efficiency for SCR with uncontrolled emission factor from AP-42 Table 1.1-3 for spreader stoker sub-bituminous coal (8.8 lb NOx/ton) and converted to lb/MMBtu using heat value for Usibelli Coal of 7,560 Btu/lb, http://www.usibelli.com/coal/data-sheet.

[9] Calculated using a 90% NOx control efficiency for SCR with uncontrolled emission rate from 40 C.F.R. 60.44b(l)(1) [NSPS Subpart Db].

[10] Calculated using a 90% NOx control efficiency for SCR with uncontrolled emission rate from most recent NOx source test, which occurred on Oct 27, 2018.

Table 4-1. RBLC Summary of SO_2 Control for Industrial Coal-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Flue Gas Desulfurization / Scrubber / Spray Dryer	10	0.06 – 0.12
Limestone Injection	10	0.055 – 0.114
Low Sulfur Coal	4	0.06 – 1.2

RBLC Review
A review of similar units in the RBLC indicates flue gas desulfurization and low sulfur coal are the principle SO_2 control technologies installed on industrial coal-fired boilers. The lowest SO_2 emission rate in the RBLC is 0.055 lb/MMBtu.

Step 1- Identification of SO_2 Control Technology for the Coal-Fired Boilers
From research, the Department identified the following technologies as available for the control of SO_2 emissions from the industrial coal-fired boilers:

(a) Wet Scrubbers
Post combustion flue gas desulfurization techniques can remove SO_2 formed during combustion by using an alkaline reagent to absorb SO_2 in the flue gas. Flue gasses can be treated using wet, dry, or semi-dry desulfurization processes. In the wet scrubbing system, flue gas is contacted with a solution or slurry of alkaline material in a vessel providing a relatively long residence time. The SO_2 in the flue reacts with the alkali solution or slurry by adsorption and/or absorption mechanisms to form liquid-phase salts. These salts are dried to about one percent free moisture by the heat in the flue gas. These solids are entrained in the flue gas and carried from the dryer to a PM collection device, such as a baghouse.

The lime and limestone wet scrubbing process uses a slurry of calcium oxide or limestone to absorb SO_2 in a wet scrubber. Control efficiencies in excess of 91 percent for lime and 94 percent for limestone over extended periods are possible. Sodium scrubbing processes generally employ a wet scrubbing solution of sodium hydroxide or sodium carbonate to absorb SO_2 from the flue gas. Sodium scrubbers are generally limited to smaller sources because of high reagent costs and can have SO_2 removal efficiencies of up to 96.2 percent. The double or dual alkali system uses a clear sodium alkali solution for SO_2 removal followed by a regeneration step using lime or limestone to recover the sodium alkali and produce a calcium sulfite and sulfate sludge. SO_2 removal efficiencies of 90 to 96 percent are possible. The Department considers flue gas desulfurization with a wet scrubber a technically feasible control technology for the industrial coal-fired boilers.

(b) Spray Dry Absorbers (SDA)
In SDA systems, an aqueous sorbent slurry with a higher sorbent ratio than that of a wet scrubber is injected into the hot flue gases. As the slurry mixes with the flue gas, the water is evaporated and the process forms a dry waste which is collected in a baghouse or electrostatic precipitator. The Department considers flue gas desulfurization with an SDA system a technically feasible control technology for the industrial coal-fired boilers.

(c) Dry Sorbent Injection (DSI)
DSI systems pneumatically inject a powdered sorbent directly into the furnace, the economizer, or the downstream ductwork depending on the temperature and the type of sorbent utilized. The dry waste is removed using a baghouse or electrostatic precipitator. Spray drying technology is less complex mechanically, and no more complex chemically, than wet scrubbing systems. The main advantages of the spray dryer is that this technology avoids two problems associated with wet scrubbing, corrosion and liquid waste treatment. Spray dry scrubbers are mostly used for small to medium capacity boilers and are preferable for retrofits. The Department considers flue gas desulfurization with DSI a technically feasible control technology for the industrial coal-fired boilers.

(d) Low Sulfur Coal
Aurora purchases coal from the Usibelli Coal Mine located in Healy, Alaska. This coal mine is located 115 miles south of Fairbanks. The coal mined at Usibelli is sub-bituminous coal and has a relatively low sulfur content with guarantees of less than 0.4 percent by weight. Usibelli Coal Data Sheets indicate a range of 0.08 to 0.28 percent Gross As Received (GAR) percent Sulfur (%S). According to the U.S. Geological Survey, coal with less than one percent sulfur is classified as low sulfur coal. The Department considers the use of low sulfur coal a technically feasible control technology for the industrial coal-fired boilers.

(e) Good Combustion Practices (GCPs)
The theory of GCPs was discussed in detail in the NOx BACT for the industrial coal-fired boilers and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control option for the industrial coal-fired boilers.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for Coal-Fired Boilers
All identified control devices are technically feasible for the industrial coal-fired boilers.

Step 3 - Rank the Remaining SO_2 Control Technologies for Industrial Coal-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from the coal-fired industrial boilers:

(a)	Wet Scrubbers	(99% Control)
(b)	Spray Dry Absorbers	(90% Control)
(c)	Dry Sorbent Injection (Duct Sorbent Injection)	(50 – 80% Control)
(d)	Low Sulfur Coal	(30% Control)
(e)	Good Combustion Practices	(Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

Aurora BACT Proposal

Aurora provided an economic analysis of the installation of wet and dry scrubber systems. A summary of the analysis is shown below:

Table 4-2. Aurora Economic Analysis for Technically Feasible SO_2 Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber (Limestone Forced Oxidation)	830	415	$88,476,054	???	$74,146
Spray Dry Absorber (Lime Spray Dryer)	830	614	$74,161,357	???	???
Dry Sorbent Injection	830	332	$32,500,898	$9,129,760	$27,493
Capital Recovery Factor = 0.1627% of total capital investment (10% for a 10 year life cycle)					

Aurora contends that the economic analysis indicates the level of SO_2 reduction does not justify the use of wet scrubbers, semi-dry scrubbers, or dry scrubber systems (dry-sorbent injection) for the coal-fired boilers based on the excessive cost per ton of SO_2 removed per year.

Aurora proposes the following as BACT for SO_2 emissions from the coal-fired boilers:

(a) SO_2 emissions from the coal-fired boilers will be controlled by burning low sulfur coal (less than 0.2% S by weight) at all times the boilers are in operation; and

(b) SO_2 emissions from the coal-fired boilers will not exceed 0.39 lb/MMBtu.

Department Evaluation of BACT for SO_2 Emissions from Industrial Coal-Fired Boilers

The Department revised the cost analysis provided for the installation of wet scrubbers, semi-dry scrubbers (spray dry absorbers), and dry scrubbers (dry sorbent injection) using the combined unrestricted potential to emit for the four coal-fired boilers, a baseline emission rate of 0.472 lb SO_2/MMBtu,[7] a retrofit factor of 1.5 for a difficult retrofit, a SO_2 removal efficiency of 99%, 90% and 80% for wet scrubbers, spray dry absorbers and dry sorbent injection respectively, an interest rate of 5.5% (current bank prime interest rate), and a 15 year equipment life. A summary of the analysis is shown below:

Table 4-3. Department Economic Analysis for Technically Feasible SO_2 Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber	1,023	558	$57,019,437	$10,759,384	$10,620
Spray Dry Absorbers	1,023	921	$51,538,353	$10,405,618	$11,298
Dry Sorbent Injection	1,023	819	$20,682,000	$6,136,043	$7,495
Capital Recovery Factor = 0.0996 (5.5% interest rate for a 15 year equipment life)					

The Department's economic analysis indicates the level of SO_2 reduction justifies the use of dry sorbent injection as BACT for the coal-fired boilers located in the Serious PM-2.5 nonattainment area.

Step 5 - Selection of SO_2 BACT for the Industrial Coal-Fired Boilers

The Department's finding is that BACT for SO_2 emissions from the coal-fired boilers is as follows:

(a) SO_2 emissions from EUs 4 through 7 shall be controlled by operating and maintaining dry sorbent injection at all times the units are in operation;

(b) SO_2 emissions from EUs 4 through 7 shall not exceed 0.10 lb/MMBtu[11] averaged over a 3-hour period;

(c) SO_2 emissions from EUs 4 through 7 shall be controlled by burning low sulfur at all times the units are in operation; and

(d) Initial compliance with the SO_2 emission rate for the coal-fired boilers will be demonstrated by conducting a performance test to obtain an emission rate.

Table 4-4 lists the proposed SO_2 BACT determination for this facility along with those for other coal-fired boilers in the Serious PM-2.5 nonattainment area.

Table 4-4. Comparison of SO_2 BACT for Coal-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	6 Coal-Fired Boilers	1380 MMBtu/hr (combined)	0.10 lb/MMBtu	Dry Sorbent Injection Limited Operation Low Sulfur Coal
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.10 lb/MMBtu	Limestone Injection Dry Sorbent Injection Low Sulfur Coal
Chena	4 Coal-Fired Boilers	497 MMBtu/hr (combined)	0.10 lb/MMBtu[11]	Dry Sorbent Injection Low Sulfur Coal

[11] BACT limit selected after evaluating existing emission limits in the RBLC database for coal-fired boilers, taking into account previous source test data from the Chena Power Plant and actual emissions data from other sources employing similar types of controls, using site specific vendor quotes provided by Stanley Consultants, and in-line with EPA's pollution control Fact Sheets while keeping in mind that BACT limits must be achievable at all times.

5. BACT DETERMINATION SUMMARY

Table 5-1. Proposed NOx BACT Limits

EU ID	Description	Rating/Size	Proposed BACT Limit	Proposed BACT Control
4	Chena 1 Coal Fired Boiler	76 MMBtu/hr	0.05 lb/ MMBtu	Selective Catalytic Reduction
5	Chena 2 Coal Fired Boiler	76 MMBtu/hr		
6	Chena 3 Coal Fired Boiler	76 MMBtu/hr		
7	Chena 5 Coal Fired Boiler	269 MMBtu/hr		

Table 5-2. Proposed SO_2 BACT Limits

EU ID	Description	Rating/Size	Proposed BACT Limit	Proposed BACT Control
4	Chena 1 Coal Fired Boiler	76 MMBtu/hr	0.10 lb/MMBtu	Dry Sorbent Injection Low Sulfur Coal
5	Chena 2 Coal Fired Boiler	76 MMBtu/hr		
6	Chena 3 Coal Fired Boiler	76 MMBtu/hr		
7	Chena 5 Coal Fired Boiler	269 MMBtu/hr		

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

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November 16, 2017

David Fish, Environmental Manager
Aurora Energy, LLC
100 Cushman St., Ste. 210
Fairbanks, AK 99701

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum from Aurora Energy, LLC (Aurora) for the Chena Power Plant by December 22, 2017

Dear Mr. Fish:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that the Aurora Chena Power Plant and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to a Serious Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measure (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as the Aurora Chena Power Plant. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analysis is a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an email to Mr. Fish at Aurora on May 11, 2017 notifying him of the reclassification to Serious and

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)
[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(4)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.
[3] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

included a request for the BACT analysis to be completed by August 8, 2017. The BACT analysis from Aurora, which included emission units found in Operating Permits AQ0315TVP03 Revision 1, was submitted by email to the Department on March 20, 2017.

ADEC and EPA reviewed the BACT analysis provided for the Aurora Chena Power Plant and ADEC is requesting additional information to assist it in making a legally and practicably enforceable BACT determination for the source. Both the ADEC and EPA comments are enclosed in this letter. ADEC requests a response by December 22, 2017. If ADEC does not receive a response to this information request by this date, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facility's infrastructure and without additional information, may select a more stringent BACT for your facility in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public review along with any precursor demonstrations and BACM analysis before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes a final BACT determination for Aurora, it must include the determination in Alaska's Serious SIP[1] that then ultimately requires approval by EPA.[2] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented prior to June 9, 2021 – 4 years after reclassification.[3]

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM) consideration. MSMs will be a required element of the state implementation plan if the State applies for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

ADEC appreciates the cooperation that we've received from Aurora. ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Denise Koch

Denise Koch, Director
Division of Air Quality

[1] https://www.gpo.gov/fdsys/pkg/CFR-2003-title40-vol2/pdf/CFR-2003-title40-vol2-sec52-21.pdf#page=1
[2] 40 CFR 51.165(a)

Enclosures:

November 16, 2017	ADEC Request for Additional Information for Aurora Energy LLC, BACT Analysis
November 15, 2017	EPA Aurora Energy – Chena Power Plant BACT Analysis Review Comments
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for Aurora Energy, LLC

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality
Jim Plosay, ADEC/ Air Quality
Aaron Simpson, ADEC/Air Quality
David Fish/Aurora Energy, LLC
Tim Hamlin, EPA Region 10
Dan Brown, EPA Region 10
Zach Hedgpeth, EPA Region 10

ADEC Request for Additional Information
Aurora Energy LLC. – Chena Power Plant
BACT Analysis Review
Environmental Resources Management Report, March 2017

November 16, 2017

Please address the following comments by providing the additional information identified by December 22, 2017. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public review. In order to provide this additional review opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public review period or based upon the new information provided in response to this information request.

This document does not represent a final BACT determination by ADEC. Please contact Aaron Simpson at aaron.simpson@alaska.gov with any questions regarding ADEC's comments.

1. Alternative Fuel Source – Page 17 of the analysis indicates that it is assumed that use of another type of coal would not reduce NOx emissions, and use of an alternate fuel is considered technically infeasible, but did not include a substantive analysis. As indicated in the Approval and Promulgation the State of Washington's Regional Haze State Implementation Plan[1], the use of SNCR and Flex Fuel[2] was selected as BART for the TransAlta coal-fired power plant. Evaluate alternative coal sources as a potential control option for the coal-fired boilers and identify energy, environmental, and economic impacts and other costs that would affect the selection of an alternative source of coal as a technically feasible control option. Evaluate the control efficiency of alternative coal sources based on a comparison of the coal's heat content as well as nitrogen and sulfur content.
2. Low Excess Air (LEA) and Overfire Air (OFA) – Operating at LEA involves reducing the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compliant boiler operation. NOx formation is inhibited because less oxygen is available in the combustion zone. Overfire air is the injection of air above the main combustion zone. Implementation of these techniques may also reduce operational flexibility; however, they may reduce NOx by 10 to 20 percent from uncontrolled levels.[3] Evaluate these technically feasible control technologies using EPA's top down approach.
3. Additional SO_2 Control Technologies – The BACT analysis does not include a substantive analysis of spray-dry scrubbing, dry flue gas desulfurization, dry scrubbing, or dry sorbent injection (DSI). All of these technologies have the potential to offer SO_2 removal, and therefore must be included in the analysis. Page 32 of the analysis indicates that the combined exhaust from the Chena Power Plant is currently controlled by a common baghouse and that installation of a dry injection or spray drying operation would require the existing baghouse be retrofit with a new PM control system to accommodate the much greater PM loading produced by a dry

[1] EPA–R10–OAR–2012–0078, FRL–9675–5

[2] Flex Fuel is the "switch from Centralia, Washington coal to coal from the Power River Basin in Wyoming. Powder River Basin coal has a higher heat content requiring less fuel for the same heat extraction, as well as a lower nitrogen and sulfur content than coal from Centralia. Flex Fuel also required changes to boiler design to accommodate Powder River Basin coal."

[3] https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

injection or spray dry system. It further states that the installation of such technologies would be cost-prohibitive and therefore technically infeasible. However, the BACT analysis must include rigorous site-specific evaluation of the technical feasibility and cost effectiveness of these technologies.

The EPA cost manual does not currently include a chapter covering dry sorbent injection (DSI). However, as part of their Regional Haze FIP for Texas, EPA Region 6 developed cost estimates for DSI as applied to a large number of coal fired utility boilers. See the Technical Support Documents for the Cost of Controls Calculations for the Texas Regional Haze Federal Implementation Plan (Cost TSD) for additional information. The Cost TSD and associated spreadsheets are located at: https://www.regulations.gov/document?D=EPA-R06-OAR-2014-0754-0008. Please update the cost analysis for these technologies and provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Provide in the analysis: the control efficiency associated with the technologies, Captured Emissions (tons per year), Emissions Reduction (tons per year), Capital Costs (2017 dollars), Operating Costs (dollars per year), Annualized Costs (dollars per year), and Cost Effectiveness (dollars per ton) using EPA's cost manual. Please see Comments 5, 6, and 7 for additional information related to retrofit costs, baseline emissions, and factor of safety.

4. BACT limits – BACT limits by definition, are numerical emission limits. However regulation allows a design, equipment, or work/operational practices if technological or economic limitations make a measurement methodology infeasible. Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for pollutant for each emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. Measures to minimize the occurrence of these periods, or to minimize emissions during these periods are control options. Combinations of steady-state control options and SSM control options can be combined to create distinct control strategies. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

5. Retrofit Costs – EPA's Control Cost Manual indicates that study-level cost estimates (± 30 percent) should not include a retrofit factor greater than 30 percent, so detailed cost estimates (± 5 percent) is required for higher factors. High retrofit cost factors (50 percent or more) may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement). Provide detailed cost analyses and justification for difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analysis.

6. Baseline Emissions – Include the baseline emissions for all emission units included in the analysis. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). NSPS and NESHAP requirements are not considered in calculating the baseline emissions. The baseline is usually the legal limit that would exist, but for the BACT determination. Baseline takes into account the effect of equipment that is part of the design of the unit (e.g., water injection and LNBs) because they are considered integral components to the unit's design. If the uncontrolled emission rate is 'soft,' run the cost effectiveness calculations using two or three different baselines.

7. Factor of Safety – If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.
8. Good Combustion Practices –For each emission unit type (coal boilers, distillate boilers, engines, and material handling) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices. Include any work or operational practices that will be implemented and describe how continuous compliance with good combustion practices will be achieved.

Aurora Energy – Chena Power Plant
BACT Analysis Review Comments
Report dated March 2017 – Environmental Resources Management

Zach Hedgpeth, PE
EPA Region 10 – Seattle
November 15, 2017

1. Equipment Life – Some of the calculations[1] submitted with the analysis use a 10 year equipment life at ten percent interest rate. The analysis must use a reasonable estimate of the actual life of the control equipment for each control technology, based on the best evidence available. The analysis must also provide written basis for the interest rate assumed if it differs from the standard seven percent rate used in the EPA Air Pollution Control Cost Manual.
2. SO_2 Control Technologies – The BACT analyses must include substantive analysis of the following four SO_2 control technologies, at a minimum: wet scrubbing (such as limestone slurry forced oxidation), spray-dry scrubbing, dry flue gas desulfurization (dry scrubbing), and dry sorbent injection. The BACT analysis must include rigorous site-specific evaluation of the technical feasibility and cost effectiveness of these technologies.
3. Control Technology Availability – Technically feasible control technologies may only be eliminated based on lack of availability if the analysis includes documented information from multiple control equipment vendors (who provide the technology in question) which confirms the technology is not available for the emission unit in question.
4. Basis for Costs and Assumptions – Documents cited in the analyses which form the basis for costs used in the analyses and assumptions made in the analyses must be provided.
5. EPA Cost Spreadsheets – The EPA has recently updated the cost manual chapters pertaining to SCR and SNCR, and developed cost spreadsheets to be used for evaluation of this technology for cost effectiveness[2]. The cost analyses for these technologies must be consistent with the updated cost manual chapter and cost spreadsheet.
6. Space Constraints – In order to establish a control technology as not technically feasible due to space constraints or other retrofit considerations, detailed site specific information must be submitted in order to establish the basis for such a determination, including detailed drawings, site plans and other information to substantiate the claim.
7. Retrofit Costs – EPA Region 10 believes that installation factors which would complicate the retrofit installation of the control technology should be evaluated by a qualified control equipment vendor and be reflected in a site-specific capital equipment purchase and installation cost estimate or quote. Lacking site-specific cost information, all factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor.
8. Potential vs. Actual Emissions – All BACT cost effectiveness calculations must use potential-to-emit (PTE), regardless of the emission unit usage history or actual historical emission rates. The

[1] See for example, NOx cost calcs-MARCH 2017 FINAL.xlsx
[2] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

facility should consider operating limits in cases where certain emission units do not need to retain relatively high PTE for facility operational purposes.

9. Control Efficiency – Cost effectiveness calculations for each control technology must be based on a reasonable and demonstrated high end control efficiency achievable by the technology in question at other emission units, or as stated in writing by a control equipment vendor. If a lower pollutant removal efficiency is used as the basis for the analysis, detailed technical justification must be provided.

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Department of Environmental Conservation

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April 24, 2015

David Fish, Environmental Manager
Aurora Energy, LLC
100 Cushman St., Ste. 210
Fairbanks, AK 99701

Subject: Voluntary BACT Analysis for Chena Power Plant

Dear Mr. Fish:

Portions of the Fairbanks North Star Borough are in nonattainment with the 24-hour National Ambient Air Quality Standard for Fine Particulate Matter (PM 2.5). The Alaska Department of Environmental Conservation (ADEC) expects that the Environmental Protection Agency (EPA) will change the nonattainment designation from a Moderate Area to a Serious Area in June 2016. Once EPA designates the area as Serious, an 18-month clock begins for submittal of an implementation plan that includes best available control technologies (BACT) analysis and determination for stationary sources with over 70 tons per year (TPY) potential to emit (PTE) for PM2.5 or its precursors.

ADEC has neither the funding nor the in depth knowledge of your facility's infrastructure to determine the most appropriate BACT for your facility. Without the information or resources necessary to conduct detailed cost analysis and produce supporting documentation, ADEC may select a more stringent BACT for your facility in order to be approvable by EPA. In addition, 18 months is likely not adequate to complete a thorough BACT analysis.

Therefore, ADEC requests that your facility voluntarily begin the BACT analysis. We request that you submit an initial BACT analysis to ADEC by December 2015 and the final BACT analysis by March 2016 to ADEC. ADEC is required to make a BACT determination for every eligible facility within the designated PM2.5 nonattainment area and final BACT determinations are ultimately reviewed by EPA and subject to federal approval as part of the federally required PM2.5 implementation plan.

Background
EPA required that ADEC submit a State Implementation Plan (SIP) because portions of the Fairbanks North Star Borough (FSNB) are in nonattainment with the health based 24-hour National

Ambient Air Quality Standard for PM2.5. ADEC submitted an initial, Moderate Area PM2.5 SIP for FNSB to EPA on December 31, 2014.

Unfortunately, this Moderate Area SIP was developed as an impracticable SIP because modeling was unable to demonstrate that attainment with the health standard was possible by December 30, 2015. Preliminary air monitoring results also indicate that FNSB will not demonstrate attainment in 2015. Attainment is calculated on a rolling three year average of the highest 98th percentile concentration at each monitor. When those monitoring results become final in May 2016 and an official three year design value is calculated, the FNSB non-attainment area will remain over the 24-hr PM 2.5 standard of 35 $\mu g/m^3$. The final determination of this design value will result in the FNSB non-attainment area being reclassified from a Moderate Area to a Serious Area[1] (40 CRF Parts 50, 51 and 93). This reclassification will happen by operation of law as outlined in Clean Air Act Sections 188 and 189. It is anticipated that the formal designation to Serious Area will occur in June 2016.

A Serious Area designation will result in several new, more stringent requirements, one of which is that all source categories in the nonattainment area that meet the BACT threshold of 70 TPY PTE for $PM_{2.5}$ and its precursor pollutants (NOx, SO2, VOC, NH3) must be analyzed for Best Available Control Measures (BACM). As part of BACM, a Best Available Control Technologies (BACT) analysis will be required. The Serious Area BACT trigger requires the same approach as a PSD/NSR BACT project. A Serious non-attainment area BACT limit is set using a top-down analysis on a case-by-case basis taking into account energy, environmental and economic impacts, and costs. The analysis must include all emission units at the source.

The timelines for completion of the BACT analysis, subsequent BACT determination, and the submittal of the Serious Area SIP are outlined in the preamble of the Particulate Matter 10 (PM10) rule and reconfirmed in the newly proposed $PM_{2.5}$ Implementation Rule[2]. Both rules require a completed SIP 18 months after designation to Serious. This 18 month time period does not allow enough time to thoroughly evaluate BACT, update the emission inventory, complete the modeling and allow for development and processing for a Serious Area SIP.

ADEC believes that it is best for facilities to complete the BACT analysis for their own facilities. ADEC does not have the funding to develop the analysis nor the in depth knowledge of each sources' infrastructure. ADEC would therefore base the cost analysis on the installation of control equipment without being able to factor in all the costs associated with retrofitting existing equipment. Without the detailed cost analysis and supporting documentation to support less stringent BACT options, it is doubtful that the BACT portions of the Serious SIP will be approvable without using the most stringent measures.

By requesting an early BACT analysis for facilities before the official Serious Area designation, it will help ADEC meet the following timelines and ultimately submit a Serious Area SIP to EPA by the required due date. Early analysis also has the potential to increase flexibility for each Stationary Source under the rules.

[1] 40 CFR Parts 50,51 and 93 http://www.epa.gov/airquality/particlepollution/actions.html

[2] http://www.epa.gov/airquality/particlepollution/actions.html

- Serious Area SIP inventory development starts: January, 2015
- BACT kick off meeting: March 5, 2015
- Submit initial BACT results to ADEC: December, 2015
- Submit complete/final BACT analysis to ADEC: March, 2016
- Serious Area SIP modeling by ADEC starts: March, 2016
- Serious Area designation by EPA (Expected): June, 2016
- Serious Area SIP draft: December, 2016
- Serious Area SIP public notice period: February, 2017
- Serious Area SIP submitted by ADEC to EPA: December, 2017

Meeting the BACT analysis requirements is a major component of a Serious SIP. This is a challenging issue. It is important that ADEC accurately reflect the contributions of industrial sources to the air pollution problem and the potential improvements available within this emission sector along with the other emission sources in the community.

ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Denise Koch, Director
Division of Air Quality

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
John Kuterbach, ADEC/ Air Quality
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality

AURORA ENERGY

December 22, 2017

Denise Koch
Director, Division of Air Quality
Alaska Department of Environmental Conservation
PO Box 111800
Juneau, AK 99811-1800

Subject: Response to November 16, 2017 request for additional information for the Best Available Control Technology Technical Memorandum from Aurora Energy, LLC (Aurora) for the Chena Power Plant by December 22, 2017

Dear Ms. Koch:

Aurora is responding to the request for additional information to supplement the Best Available Control Technology (BACT) Technical Memorandum provided to the Alaska Department of Environmental Conservation (ADEC) on March 20, 2017. In response, a detailed BACT analysis for sulfur controls is included as an addendum to the original BACT analysis. We are confident that our initial submittal and enclosed response are sufficient to make a preliminary BACT determination consistent with our selected BACT. Aurora is convinced expending additional and substantial resources to provide further analysis is not warranted considering that ADEC has established, through moderate area planning efforts, that our facility's contribution to ground level particulate matter during air quality events is minimal.

Aurora realizes that a BACT analysis must be conducted for applicable stationary sources regardless of the level of contribution to the problem or impact on the area's ability to achieve attainment. However, the request for additional information hints at the Departments next steps of requiring heat and power producers, such as Aurora, to install technology which will have minimal impact on bringing the area into attainment.

Collectively, the large stationary sources contribute less than 10% of the total $PM_{2.5}$ concentration as illustrated by ADEC.[1] According to the moderate area planning efforts, Aurora makes up less than 1% of the contribution from large stationary sources.[2] The cost to mitigate Aurora's less than one percent contribution to ground-level particulate matter would require tens of millions of dollars in capital investments and annualized operating costs which would be passed on to the consumer in increased power and district heat rates. Current electric rates in the Interior are already some of the highest in the country. Market competition dictates that district heating costs are priced to be competitive with oil and natural gas. An increase in district heat

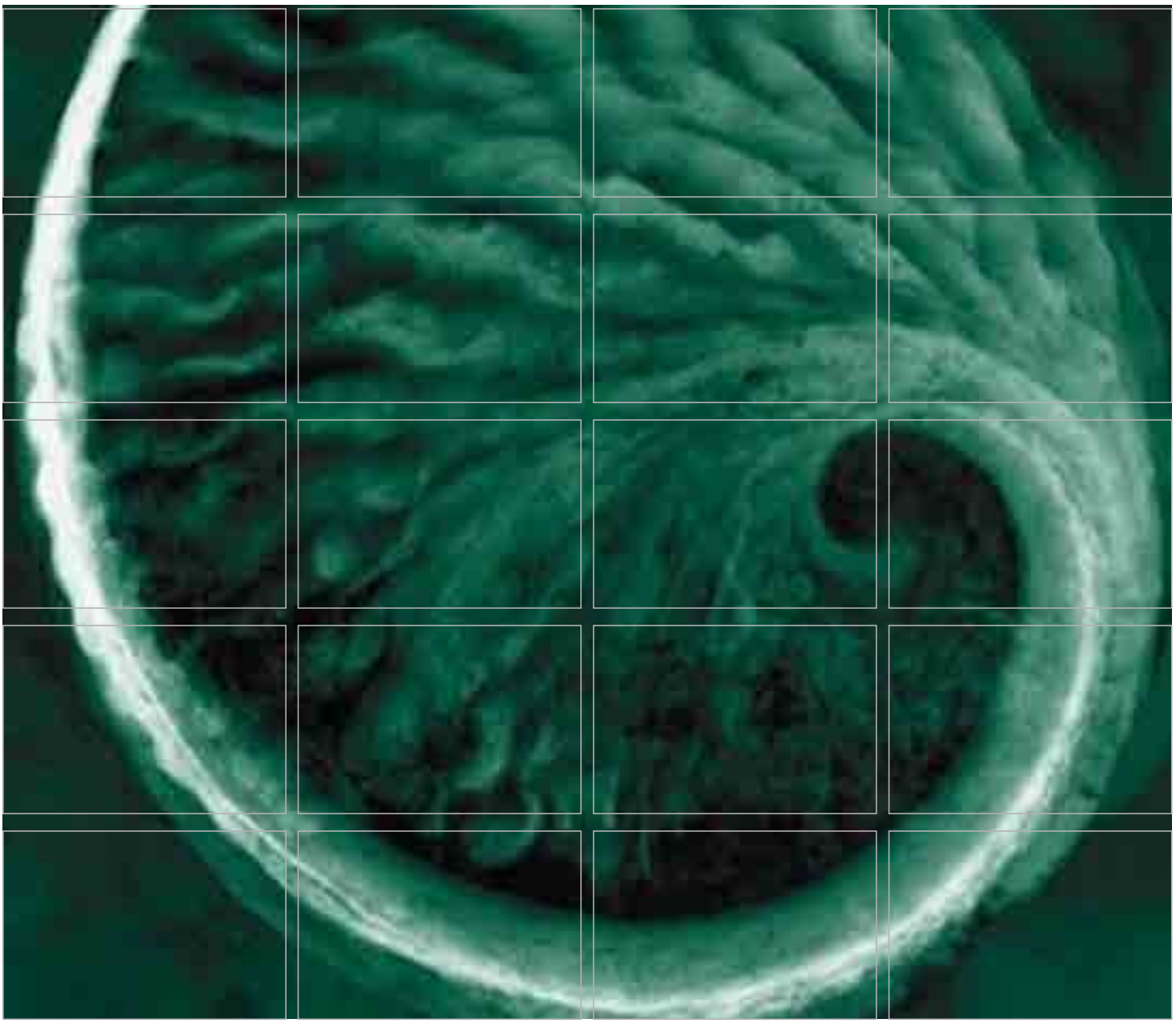
[1] Clear the Air Conference. 2017. http://dec.fairbanks.ak.us/transportation/Pages/ASConference2017.aspx. Source Apportionment Presentation, Slide 21, accessed 11/29/2017.
[2] State Implementation Plan, ADEC. 2014. http://dec.alaska.gov/air/anpms/comm/docs/fbks/Final-2nd-PM2.5-SIP-Section-Adopted-09.07.16.pdf, pg 167 of 213. Accessed 11/29/2017.

rates could encourage consumers to switch to ground-level heating sources, such as oil and wood, which would exacerbate the area's air quality problems and impede local progress toward attainment.

In short, BACT is prohibitively costly, impractical, and ineffective in this situation. The implementation of additional control technology on Aurora would, at best, provide minimal benefit to air quality and would likely result in unintended consequences. Aurora believes that ADEC, EPA and Aurora could work together to identify a mechanism in the planning process that recognizes the air quality benefit of Aurora's district heating system which displaces the equivalent of over two million gallons of wintertime ground-level heating oil emissions. As such, district heating is a proven solution to Fairbanks' air quality issues. Aurora hopes that ADEC will take these points into consideration in anticipation of the Department's preliminary BACT determination for public review.

Sincerely,

Buki Wright
President



Addendum to Best Available Control Technology Analysis

Prepared for:
Aurora Energy, LLC

Chena Power Plant
Fairbanks, Alaska

December 2017

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The business of sustainability

Addendum to Best Available Control Technology Analysis

Chena Power Plant
Fairbanks, Alaska

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December 2017



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ACRONYMS AND ABBREVIATIONS

ADEC	Alaska Department of Environmental Conservation
BACT	best available control technology
CAA	Clean Air Act
CMB	chemical mass balance
EPA	Environmental Protection Agency
FGD	flue gas desulfurization
FNSB	Fairbanks North Star Borough
ft	foot or feet
GVEA	Golden Valley Electric Association
LAER	Lowest Achievable Emission Rate
lb/hr	pound per hour
MW	megawatt
NAAQS	National Ambient Air Quality Standard
NOx	oxides of nitrogen
NSPS	New Source Performance Standards
NSR	Normalized stoichiometric ratio
OH	hydroxyl
PM	particulate matter
ppm	parts per million
PSD	Prevention of Significant Deterioration
RACT	reasonable available control technology
SIP	State Implementation Plan
SO_2	sulfur dioxide
ton/yr	tons per year
U.S.	United States
VOC	volatile organic compounds
$\mu g/m^3$	micrograms per cubic

1 INTRODUCTION

As described in the original Best Available Control Technology (BACT) Analysis report, Aurora Energy, LLC (Aurora) operates four coal-fired boilers, three similarly-sized smaller units and one larger unit, at the facility known as the Chena Power Plant (Chena).[1] The combined exhaust from the four boilers at Chena is currently directed to a single fabric filter for control of particulate matter (PM). Figure 1 presents an aerial view of the Chena facility where the four coal-fired boilers are located. The duct work from the three smaller boilers can be seen coming out of two different buildings along 1st Avenue. The duct work from the larger boiler is not clearly visible, but comes out of a third building and connects to the other combined ducts just prior to entering the south side of the fabric filter housing. The fabric filter housing, visible as a blue structure in the figure, is one of the larger individual structures that occupies the site. The PM collected in the fabric filter is conveyed to the adjacent ash silo for storage until trucked off site.

The four Chena boilers combust low sulfur coal to achieve a sulfur dioxide (SO_2) emission rate equivalent to 0.39 pounds of SO_2 per million Btu of heat input (lb SO_2/MMBtu). The coal is "local" coal mined at the Usibelli Coal Mine in Healy, Alaska.

The techniques available for controlling SO_2 emissions from a coal-fired boiler include the following:

- Use of flue gas desulfurization (FGD) technology
  - Wet scrubber
  - Dry scrubber (lime injection and spray dryer/absorber)
  - Limestone or other dry sorbent injection

Most wet FGD systems employ two stages: one for fly ash removal and the other for SO_2 removal. In wet scrubbing systems, the flue gas first passes through a fly ash removal device, either an electrostatic

[1] Environmental Resources Management, Inc., Best Available Control Technology Analysis, Chena Power Plant, Fairbanks, AK, revised March 2017.

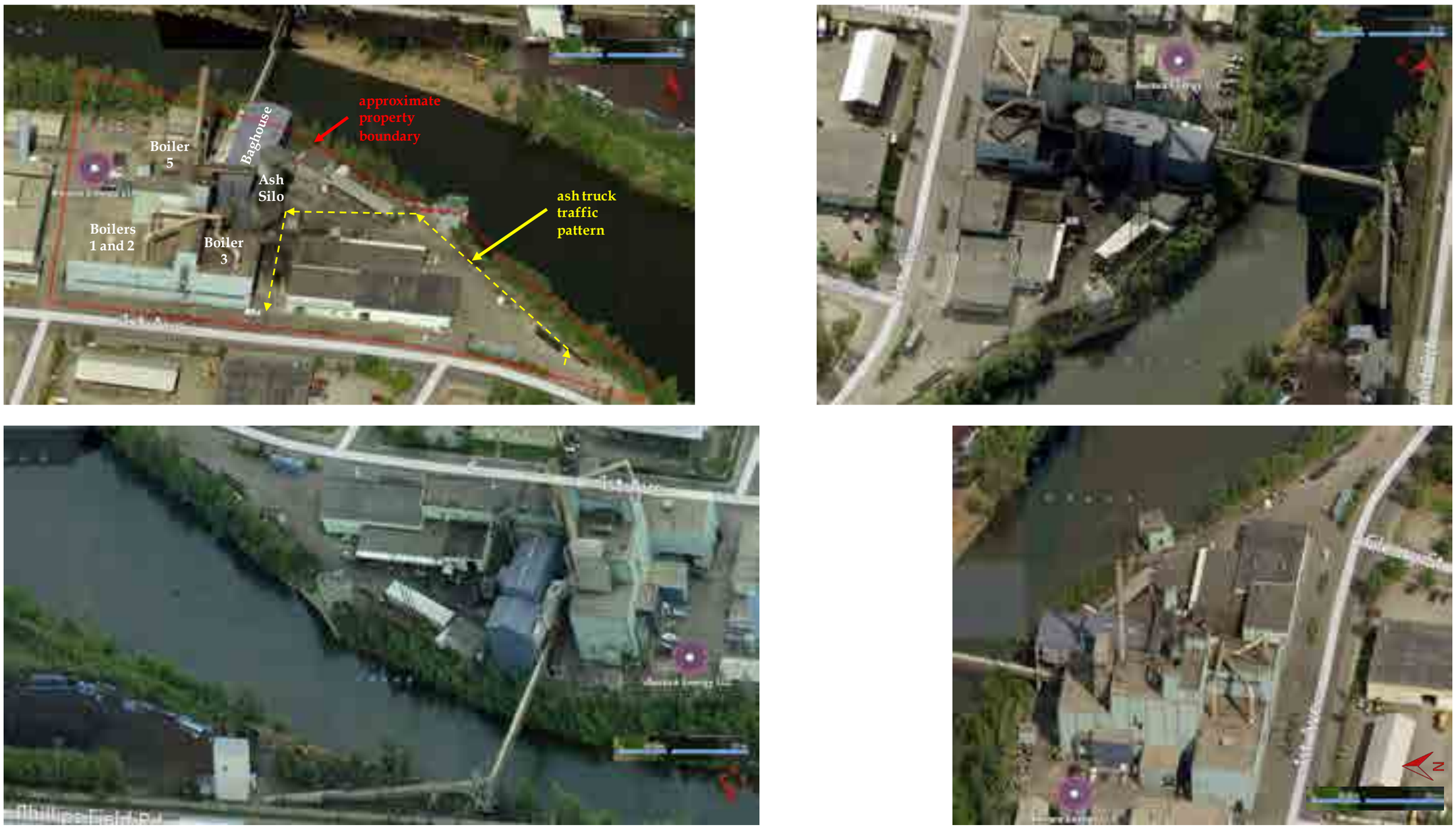


Figure 1. Aerial View of Chena Power Plant.

precipitator (ESP) or a fabric filter, and then into the SO_2 absorber. Due to cost constraints, wet FGD systems are not commonly used to reduce SO_2 emissions from boilers combusting low-sulfur coal. The original Chena Power Plant BACT Analysis presented a detailed discussion of the technical feasibility and cost of using a wet scrubber at Chena. Wet scrubbing technology was discounted as BACT in the original analysis due to the high cost-effectiveness (although many other technical challenges, such as space constraints, exist when considering wet scrubber technology at Chena). Additional discussion of FGD using a wet scrubber is therefore not needed at this time.

1.1 ADDITIONAL SO_2 CONTROLS SELECTED FOR EVALUATION

This BACT Addendum concentrates on evaluation of dry FGD technology, which consists of the spray dryer/absorber (SDA) option and the dry sorbent injection (DSI) option. In SDA or DSI operations, the SO_2 is first reacted with the sorbent, and then the flue gas passes through a PM control device.

The ability of a SDA or DSI system to achieve any reasonable degree of SO_2 control is highly influenced by the presence of other constituents in the gas stream that will compete with the calcium or sodium injected into the gas. In the case of coal-fired boiler flue gases, the primary competing constituent is chlorine. Chlorine present in the coal will form hydrochloric acid (HCl) in the flue gas and consume a portion of the injected lime. In an SDA system, actual sorbent consumption is influenced by the discharge temperature selected for the system, as this controls the amount of water sprayed into the flue gas. .

The ability to employ an add-on SO_2 control system also is influenced by site-specific factors, including space limitations. Use of a SDA or DSI system in concert with the somewhat peculiar equipment orientation at Chena, i.e., four boilers controlled by a single fabric filter, would require major alterations of the existing ductwork and possibly the fabric filter. The boiler houses and ducts would need to be retrofit with various equipment items to accommodate the sorbent delivery systems and PM handling systems required by a SDA or DSI system.

The following paragraphs present an overview of these two selected dry FGD technologies in general and a description of some of the site-specific issues associated with their use at Chena.

1.2 *SPRAY DRYER/ABSORBER*

A U.S. EPA Air Pollution Control Technology Fact Sheet for FGD technologies states that scrubbers are capable of reduction efficiencies in the range of 50 to 98%.[2] The highest removal efficiencies are achieved by wet scrubbers, and the lowest by dry scrubbers (typically less than 80%). Low SO_2 loadings to a dry absorber, as are obtained when using low sulfur coal, tend to produce lower removal efficiencies, between 40% and 70%. For comparison, the Consent Decree between the Golden Valley Electric Association, Inc. (GVEA) and the US EPA (dated November 19, 2012) and the subsequent Minor Permit issued by the Alaska Department of Environmental Conservation (ADEC) specified a 30-day SO_2 emission rate of no greater than 0.10 lb/MMBtu for Healy Power Plant (Healy) Unit 2 in Healy, AK while using SDA.[3] The Healy facility combusts similar coal as the Chena Power Plant, which produces an average uncontrolled emission rate of 0.39 lb SO_2/MMBtu. Achieving an emission rate of 0.10 lb SO_2/MMBtu thus represents a 74% reduction of average uncontrolled SO_2 emissions, which generally falls within the published range of performance for a SDA system.

In SDA systems, a slurry of sorbent material and water is fed to a spray dryer tower. In the tower, the slurry is atomized and injected into the gas, where droplets react with SO_2 as the liquid evaporates. This action produces a dry product that is collected in the bottom of the spray dryer and in the downstream PM removal equipment (i.e., fabric filter or electrostatic precipitator, ESP). The majority of the reaction takes place in the spray dryer. When a fabric filter is used, as the PM collects on the filter cloth, a filter cake would develop and allow the gas a second chance to react with the reagent, thus increasing utilization of the reagent and control efficiency. The fabric filter or ESP, downstream of the spray dryer, removes the PM, ash, reaction products (e.g., $CaSO_3$, $CaSO_4$, Na_2SO_4), and unreacted sorbent. The waste product can be disposed, sold as a by-product (depending on its quality), or recycled to the slurry. Various calcium and sodium-based reagents can be utilized as sorbent. SDA systems typically inject lime because it is more reactive than limestone and less expensive than sodium-based reagents. SO_2 control efficiencies

[2] US EPA, Air Pollution Control Technology Fact Sheet, Flue Gas Desulfurization, EPA-452/F-03-034, https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf, accessed December 18, 2017.
[3] Technical Analysis Report – Permit AQ0173MSS01, April 14, 2014, Golden Valley Electric Association-Healy Power Plant.

are somewhat comparable for wet limestone scrubbers and spray dry systems, however, the capital and operating cost for spray dryer systems are lower than for wet systems, because equipment for handling liquid reagent and wet waste products is not required. In addition, carbon steel can be used to manufacture the absorber because the flue gas is less humid.

It is reasonable to expect that SDA technology performance depends on the facility-specific process characteristics. The properties most important for a SDA application are an inlet gas temperature that allows the slurry to be evaporated in the flue gas (a necessity for a spray dry scrubber), adequate mixing and residence time that allow the sorbent to react with the SO_2 in the gas, and the use of a PM control device to separate the reaction products from the gas stream.

1.2.1 Site-specific Considerations for Using SDA at Chena

Flue Gas Take-off Point--The Chena plant employs a fabric filter to remove the PM from the combined flue gases of the four boilers operating at the site. A very short duct run, only about 10 feet, exists between the location where the flue gases are combined and the combined gas enters the fabric filter housing. At this point, the flue gas from Boiler 5 combines with the previously-combined flue gas from Boilers 1, 2, and 3. Three general SDA equipment orientations are possible for taking off flue gas for treatment in a spray dryer tower at Chena. The first orientation would take the flue gas from the point where all boiler flue gases have been combined prior to entering the fabric filter, i.e., in the 10-foot (ft) duct run. A second orientation would take the flue gas from Boiler 5 only (at some point prior to the 10-ft duct run) and provide control only of the SO_2 emitted by the larger boiler. A third orientation would take the combined flue gas as it exits the fabric filter. In any of these orientations, construction of duct work needed to deliver flue gas to the spray dryer tower would be complicated. Major changes to the gas flue flow regime would occur for any take-off point prior to the fabric filter. Major structural modifications of the fabric filter housing would be needed to accommodate a take-off point downstream of the fabric filter.

Spray Dryer Tower Location-- The Chena site is extremely congested, and very little vacant space is available for new construction. Therefore, spatial considerations are necessary when locating a spray dryer tower. A similarly sized boiler facility exists at the Golden Valley Electric Association (GVEA) plant in Healy, Alaska. The Healy Unit #2 boiler (683 MMBtu/hr) employs a SDA system, which is a similarly sized boiler

burning run-of-mine coal from Usibelli. The spray dryer tower at the GVEA plant is 34 ft 9 in in diameter and stands 36 ft 9 in from the ground with a 29 ft 4 in, 60° Cone Hopper. Because of the congested area at Chena, a spray dryer tower would have to be located on the northern boundary of the property south of the river on the east or west of the outfall house. That location would situate the tower approximately 150 to 250 ft away from the combined flue gas junction just prior to the fabric filter inlet. After exiting the spray dryer tower, the treated gas would be redirected back to the 10-ft duct run at the fabric filter inlet for removal of PM. The baghouse design for the flue gas temperature at the inlet is 350 °F. Typically, the combined flue gases are between 300 and 315 °F at the inlet of the baghouse. The outlet temperature varies between 285 and 300 °F. The optimal temperature for SO_2 removal in a SDA is 10 to 15 °C below the saturation temperature to maximize the removal of SO_2. At approximately 15% moisture of Chena's flue gas, the saturation temperature would be around 88 °C (190 °F). This would cause wet solids to deposit on the absorber and downstream equipment. For spray dry systems, the temperature of the flue gas exiting the absorber must be 10 to 15 °C (20 to 50 °F) above the adiabatic saturation temperature.[4] The Healy plant inlet temperature is 300 °F and exists at 175 °F; however the O&M manual for the SDA references 185 °F as the outlet set point. Regardless, the long return duct run from the tower to the fabric filter would require reheating.to prevent moisture from condensing out of the gas. The reheating requirements will add to the increase in energy consumption from the control technology.

In a second option, Boiler 5 flue gas would be treated independently with a SDA system. For this option, the flue gas take-off point could be closer to the boiler, but the tower itself will still need to be located at a spot with available space approximately 100 to 200 ft away, and gas reheat would still be required as described for option 1. A separate spray tower for the combined flue gases from Boilers 1, 2, and 3 would have to be situated in the same area on the north side of the property as described above with ducting between 150 and 250 ft. This configuration is essentially the same as described in option 1 and therefore is not considered independently as an option.

[4] Ibid (Air Pollution Control Technology Fact Sheet).

A third option would place the spray dryer tower after the fabric filter. This orientation would require a second fabric filter housing to be constructed at the facility. Based on an air-to-cloth ratio of 10 ft/min for lime[5], 0.39 lb/MMBtu SO_2 in the flue gas, a stoichiometric conversion from SO_2 to $CaSO_3$ (1.875), and a 75% removal efficiency, the filter area required of the secondary baghouse would be 25,000 ft^2. The current baghouse has a filter area of 61,000 ft^2 and a footprint of 35,035 ft^2 (not including the ducting and ID fans). Assuming the profile would be similar for the secondary baghouse, a footprint of 14,360 ft^2 would be required. Space is not available on Aurora's property for the installation of a second baghouse which would be about 40% the size of the current baghouse.

Existing PM Collection and Storage Equipment--A SDA placed upstream of the existing Chena fabric filter would have several negative operational impacts. First, the amount of additional PM generated and sent to the existing fabric filter could cause the existing filter system to clean more continuously. The baghouse cleans when the differential pressure drop between inlet and outlet reaches 6 inches water column. The baghouse currently cycles through cleaning about 24 times a day. Assuming 4% fly ash is generated at an average operating load of 220,000 ton/yr of coal (2,000 lb/hour fly ash), the increase in fly ash at the projected maximum coal input rate of 283,824 ton/yr (2,592 lb/hour fly ash) would cause the baghouse to cycle 31 times a day (24 cycles/day x 2,592 lb/hr ÷ 2000 lb/hr). The additional particulate generation could increase the ash load to the baghouse by 267 lb/hr (0.39 lb SO_2/MMBtu at 75% removal efficiency). The additional load would increase the baghouse daily cleaning cycle to 34. The additional cycling of the system would require an increase in electrical consumption and operational maintenance.

While the particle loading could be accommodated by the existing baghouse, it is unlikely that additional airflow from added control technologies could be accommodated through the baghouse at maximum load. A stoichiometric analysis of the combustion flue gas, with 7% oxygen yields 11.1 lb of exhaust/lb of coal. The density of the exhaust air

[5] EPA. 2002. Air Pollution Cost Control Manual: Section 6, Particulate Matter Controls. https://www3.epa.gov/ttncatc1/dir1/c_allchs.pdf. Research Triangle Park, North Carolina.

from the plant, based on average test data, is 0.048 lb/ft^3.[6] If a maximum projected heat input rate of 486 MMBtu/hr (283,824 ton/yr coal) were realized, the air flow through the baghouse would be 250,000 ft^3/min, which is the rated capacity of the baghouse. The stoichiometric analysis does not consider air infiltration which would increase the air flow to the baghouse beyond its capacity. Additional airflow needed for add-on control technologies would exceed the design air flow of the existing baghouse.

The duct reconstruction at the flue gas take-off point as well as the point where the treated flue gas is re-introduced to the fabric filter inlet also will require additional gas-handling equipment. Therefore, the additional PM load to the fabric filter and silo would necessitate an increase in electricity consumption and operational maintenance necessary to address potential plugging and filter replacement.

A take-off point after the existing fabric filter would alleviate the excessive PM loading issue. This orientation would require that a new outlet gas duct be retrofit onto the existing fabric filter housing to deliver the outlet gas to a second fabric filter. The existing filter vents through a roof monitor (also referred to as a monovent). In order to direct the fabric filter outlet gas to a downstream SDA system, one would need to open the top of the existing filter housing, weld new gas distribution plates to the outlet plenum, and construct a single gas outlet duct. This outlet duct would then be directed to the downstream SDA system, new fabric filter, and PM silo. The structural stability of the existing filter housing may be inadequate for handling the additional stress of the gas distribution components, in which case, extensive structural reinforcement would be needed. Construction of these items would demand more space than is available. As is clearly apparent by looking at Figure 1, the site has no extra space in which to build any such equipment for PM collection and storage. Additionally, operation of such a system orientation would increase the electric consumption at the facility. The average total electrical power consumption for the SDA system at the Healy Clean Coal

[6] Airflow Sciences Corporation. Chena PJFF Inlet Ductwork Flow Modeling. Fairbanks, Alaska. October 2015.

Project for their Healy Unit #2 during a performance test was 550.5 kW.[7] The Chena Power Plant baghouse power consumption is 460 kW. An SDA would potentially double the pollution control load of the plant and decrease the net sales of power approximately 2.4%.

Contamination of Collected Particulate-- The ash constituent loading would change as a result of adding sorbents used in the process. This change could render the ash unsuitable for beneficial use as a fill material. Fly ash collected at Chena is beneficially used as a construction fill material. The addition of sorbents could compromise the leaching characteristics of the ash which is a metric to determine its suitability for beneficial structural fill. Without adequate testing, there is uncertainty as to the impact of the sorbents on the leaching characteristics of the ash. Use of an SDA system downstream of the exiting fabric filter could alleviate this issue if the sorbent byproducts were addressed separately from combustion ash.

***Facility Space Limitations for Ancillary Equipment*--** Regardless of whether a SDA is placed upstream or downstream of the existing fabric filter, the spatial requirement of the system and auxiliary equipment will be difficult to accommodate. A SDA system would employ lime, Trona, or sodium bicarbonate as the scrubbing reagent. Extensive preliminary engineering would need to be performed to define space requirements for the scrubber tower(s); raw reagent receiving areas, piping, conveyors, and storage tanks and silos, and reagent mills; as well as similar equipment for handling the solid waste material generated in the system. The GVEA Healy plant, in addition to the SDA vessel, houses conveyors, recycle surge bin (12-ft diameter), slurry feed tank (7.5-ft diameter), slurry mixing tank (10.5-ft diameter), mill classifier, and a storage silo for the sorbent.

Much of the equipment needed for an SDA system would be large items that occupy a substantial footprint. As can be seen in Figure 1, very little unused space exists at the facility. No space exists for an enclosed spray tower, and therefore a tower would need to be sited outdoors. No space exists between the combined boiler ducts and the fabric filter (as seen in Figure 1) to insert a spray tower. Because all of these duct runs are located

[7] Alaska Industrial Development and Export Authority. 1999. Spray Dryer Absorber System Performance Test Report, Healy Clean Coal Project. Healy, AK.

outdoors, maintaining the flue gas temperatures needed for the reaction and preventing moisture in the fabric filter will be expensive and difficult. Finally, as can be visualized by looking at Figure 1, the site does not have enough unused area to accommodate a dry material receiving operation and slurry preparation area. There is a likelihood that material receiving would have to occur on the north side of the Chena River. This would necessitate another river crossing which adds another layer of complexity to the process. Ultimately, the spatial considerations for the equipment would require a building to house the technology and heat to maintain the temperatures needed for the application. The parasitic load from electrical consumption and heating for the application would be substantial; at the least greater than 2.5% of current net generation.

1.3 DRY SORBENT INJECTION

In the utility industry, SO_2 may be removed by injecting a dry sorbent (limestone, Trona, or sodium bicarbonate are the common sorbents) into the combustion gases, typically above the burners or in the backpass before or after the air heater. Furnace DSI involves injection of the sorbent into the boiler system at a location downstream of the combustion zone through special injection ports. In DSI, the sorbent contacts the hot gas, decomposes, and reacts in suspension with SO_2 to form reaction products, such as calcium sulfate ($CaSO_4$), when using lime or limestone, or sodium sulfate (Na_2SO_4) when using Trona (sodium sesquicarbonate) or sodium bicarbonate. The reaction products, unreacted sorbent, and fly ash are removed at the PM control device (either an ESP or fabric filter) downstream from the boiler.

DSI has historically been used for reducing concentrations of hydrochloric acid (HCl), mercury, and sulfates (SO_3) from coal-fired boiler flue gas. Recently, DSI has seen greater use primarily as a system to comply with the Maximum Achievable Control Technology (MACT) requirements for boilers, aka, Boiler MACT. As operators began using DSI for HCl control in response to Boiler MACT, incidental removal of SO_2 was also being observed. SO_2 removal efficiencies of 30% to 70% have been reported for DSI in the utility industry when sorbent is injected and mixed at optimum conditions, and higher removals have been demonstrated in test/pilot operations. However these performance levels have yet to be widely demonstrated on a long-term continuous basis at permanent installations. For comparison, the Consent Decree between GVEA and the US EPA and the subsequent Minor Permit issued by the ADEC specified a 30-day SO_2 emission rate of no greater than 0.30 lb/MMBtu commencing

September 30, 2015 or 18 months after Healy Unit 2 first fired coal.[8] This emission rate represents a 23% reduction of average uncontrolled SO_2 emissions through the use of a DSI system.

In practice, the reaction chemistry of a DSI system is very straight forward. As a result, some level of SO_2 removal should be obtained when conditions exist that allow the reaction to take place. The performance of a DSI system for SO_2 removal is a function of several factors:

- Sorbent type
- Flue gas temperature at the injection location
- Sorbent particle size
- Sorbent injection rate, or Normalized Stoichiometric Ratio (NSR)
    - Extent of sorbent-to-gas mixing
    - Reaction residence time prior to the PM collection device
- PM control device type
- Flue gas properties
    - Concentrations of other acid gases competing with SO_2 reaction chemistry
    - Flow distribution and moisture content

Discussion of some of the more important aspects of DSI system performance is provided in the following paragraphs.

1.3.1 Sorbent Type

It is generally accepted that sodium-based sorbents (Trona and sodium bicarbonate) produce higher SO_2 removal rates than calcium-based sorbents (lime or limestone). This observation has been borne out by the operations at the Healy, AK coal-fired boiler facility. When first implemented, the DSI system at the Healy facility was based on limestone injection. After a period of operation, the limestone-based DSI system was replaced with a Trona-based system to improve performance. The Trona-based system was subsequently replaced with a sodium bicarbonate DSI system to further improve performance. As was the case at Healy, coal-fired boiler installations seem to be moving to use of the sodium sorbents to achieve SO_2 removal efficiencies of at least 40%. Therefore, no additional discussion of calcium sorbents is provided herein.

[8] Ibid (Technical Analysis Report).

1.3.2 Flue Gas Temperature at the Injection Location

Flue gas temperature will have a direct effect on reaction kinetics. A higher efficiency can be achieved when DSI is injected at a location where the flue gas temperature is approximately 500° F, and removal becomes less as the injection location is cooler or hotter. When a sorbent particle is introduced into a hot flue gas, it decomposes to sodium carbonate and the surface area of the particle increases. As reported in a recent Technical Report, the particle surface area begins to increase at 300° F (the minimum recommended sorbent injection temperature) and peaks at 500° F (the "optimum" temperature).[9] Above 500° F the particle structure begins to change and particle sintering may begin, effectively decreasing the activity of the particle. As the particle surface areas increases, a greater portion of the sorbent material is available to participate in the reaction with SO_2, thus producing an increased removal rate.

1.3.3 Sorbent Particle Size

Sorbent consumption and acid gas removal rates have been improved over the past several years with the understanding of the importance of uniform sorbent particle size and high sorbent surface areas. To effect these improvements, most DSI systems now employ in-line milling equipment for all sodium sorbents.

1.3.4 Sorbent Injection Rate (or NSR)

The NSR reflects the sorbent utilization rate, or the efficiency by which the injected sorbent is utilized in the SO_2 removal reaction. All else being equal, the SO_2 removal rate increases (up to an upper limit) as the NSR is increased. In addition to the particle size factor discussed above, sorbent-to-gas mixing and residence time prior to entering the PM control device will influence the NSR needed to achieve a desired removal rate. Poor mixing conditions and low residence (i.e., reaction) times will produce the situation where a greater NSR is needed to achieve the same level of performance as observed in a well-mixed, adequately timed duct system. A DSI cost model defines its typical NSR for milled Trona with an ESP as

[9] Dr. Sahu, Ranajit, Technical Report on Dry Sorbent Injection (DSI) and Its Applicability to TVA's Shawnee Fossil Plant, Commissioned by the Southern Alliance for Clean Energy, Knoxville, TN, April 2013.

1.40 (target removal is 50%), and its typical NSR for milled Trona with a fabric filter as 1.55 (target removal is 70%).[10] These NSR represent sorbent injection rates of 40% and 55% above the stoichiometric amount of Trona needed for the SO_2 reaction. When other than optimum conditions exist for DSI use (such as poor mixing or inadequate residence time), the NSR must be increased to account for less than optimum sorbent utilization. The actual performance of a DSI system can vary from 0% to 90% depending on the NSR and other operating characteristics.[11]

A separate operating issue has been observed when DSI systems operate with a high NSR. As the NSR increases, a brown nitrogen oxide (NOx) plume begins to be generated and emitted from the stack. This situation produces an undesirable environmental impact of using a DSI system.

1.3.5 PM Control Device Type

One of the more influential DSI system parameters is the PM collection system. This influence is important because the sorbent remains available to participate in the SO_2 reaction while in the ESP or fabric filter used to collect the PM in the flue gas. A system that employs a fabric filter will inherently achieve a greater SO_2 removal rate than one that employs an ESP because a dust cake that builds on the surface of the filter bags provides additional surface area upon which the SO_2 can react. Although studies on the effect of bag cleaning mechanisms could not be found, a pulse air jet bag cleaning system would appear to produce a lesser (secondary) SO_2 removal rate than a shaker system due to the fact that the pulse air system is designed to periodically completely break the dust cake from the cloth, as opposed a shaker cleaning system in which some remnant dust particles would remain on the surface and in the weave of the cloth after cleaning.

[10] Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2 Control Cost Development Methodology (Final report), prepared for Systems Research and Applications Corporation, March 2013.
[11] Ibid (Sargent & Lundy).

1.3.6 Flue Gas Properties

The ability of DSI system to achieve any reasonable degree of SO_2 control is highly influenced by the presence of other constituents in the gas stream that will compete with the sodium injected into the gas. In the case of coal-fired boiler flue gases, the primary competing constituent is chlorine. Chlorine present in the coal will form HCl in the flue gas and consume a portion of the injected sorbent. Careful consideration of the chlorine content of the coal, therefore, is needed when sizing the system and defining the NSR.

Distribution of flow with the flue gas duct work is important for at least two reasons: 1) the distribution influences in-duct mixing, and 2) flow distribution may contribute to sorbent deposition within the duct or impaction and plating upon the walls. Many DSI equipment vendors offer Computational Fluid Dynamic (CFD) modeling of plant duct flows to predict and enhance sorbent distribution in flue gas, thereby maximizing performance and minimizing sorbent usage.

1.3.7 Site-specific Considerations for Using DSI at Chena

Two aspects of boiler operation at Chena are good for considering a DSI system: 1) the facility uses a fabric filter for PM control, which improves DSI performance by allowing for continued contact between SO_2 and sorbent, and 2) the flue gas temperature entering the fabric filter is approximately 300° F, which is near the minimum recommended temperature at the sorbent inject location. Some aspects of the Chena operation and site, however, are less than optimum for retrofitting a DSI system, and some of these aspects (i.e., constraints) are discussed below.

Stoker Design— Many of the initial DSI systems were demonstrated on fluidized bed combustion units and employed sorbent injection into the boiler combustion zone. Unlike a fluidized bed combustor, the old traveling grate stokers used at Chena are not designed for suspension burning. Sorbent injected into the combustion zone in a stoker unit would settle onto the stoker coal bed and become unavailable for reaction. This would result in dead burning of the sorbent. For this reason, sorbent injection would need to occur outside of the combustion zone in downstream duct locations that are cooler than in the combustion zone. As noted above, however, adequate temperature exists in other duct locations to allow DSI use at Chena.

Alternative DSI System Orientations — Three basic DSI system orientations exist at Chena. Sorbent could either be injected into duct work for each individual boiler (four injection locations), a single injection location where all four duct systems converge just prior to entering the fabric filter, or at two locations—one for the large boiler and one for the three combined small boilers. The simplest of these options would be a single injection point. This option could, however, impact sorbent utilization (see NSR discussion below). Regardless of the selected orientation, a DSI system could be provided that employs a single sorbent receiving and storage area and associated conveying system with or without splitters to convey sorbent to more than one injection location. Assuming that the sorbent is milled in-line, immediately prior to injection, at least two sorbent mills would be needed for each injection location (one mill for use and one redundant mill). Therefore, between two and eight sorbent mills (depending on the number of injection points and ease of moving redundant equipment between injection points when needed) would be required depending on the DSI system orientation.

Factors Influencing NSR — The congested site layout will potentially adversely impact the amount of sorbent needed (i.e., NSR) to achieve reasonable reductions using DSI. Figure 1 previously showed the arrangement of flue gas duct work for Boiler 1, 2, and 3. Although not visible in Figure 1, these three duct systems combine with the flue gas duct work for Boiler 5 just prior to entering the fabric filter. If a single sorbent injection location is specified, this location would provide a short mixing zone with a low residence time prior to the fabric filter. Approximately 10 ft of duct is available between the location where the flue gas ducts converge and the combined gas enters the fabric filter. Gas velocities between 55 ft per second (ft/s) and 75 ft/s exist at this location, indicating that the sorbent and flue gas would be afforded only between 0.1 and 0.2 seconds of mixing/residence time prior to entering the fabric filter housing. The GVEA Healy plant's Unit #1 (305 MMBtu/hr boiler) has a 100-ft run prior to the baghouse from the injection point. Assuming GVEA maintains similar duct velocity as Chena, the GVEA DSI system operates with a reaction time of 1 or 2 seconds of mixing prior to entering the fabric filter housing. The mixing zone and residence time at the Chena plant would be very short (10 times less) in comparison and will potentially require additional sorbent be injected to achieve any sort of SO_2 removal. This will, in turn, reduce the cost effectiveness of a DSI system (i.e., increase the operating cost and reduce the removal rate).

Sorbent injection into individual boiler duct will eliminate the short mixing zone and residence time, but this equipment orientation may also

adversely impact NSR. The flue gas from each boiler goes through several turns (up to seven) prior to entering the fabric filter housing. While this duct orientation yields good mixing, it may also promote particle deposition and plating on to the inside of the duct work, thereby causing some of the injected sorbent to be wasted and unavailable for reaction.

***Existing PM Collection and Storage Equipment*—**Similar to the issues introduced when discussing SDA, additional PM load to the fabric filter and silo would necessitate an increase in electricity consumption and operational maintenance.

Also, potential changes to the constituent loading and leaching characteristics of the ash due to sorbent use could render the ash unsuitable for beneficial use fill material. Aurora currently provides its collected ash to developers in the area for beneficial use as a fill material. The incorporation of sorbent to the ash could alter the properties of the ash such that it no longer meets the metric used to evaluate its benefit. If the ash from the Chena plant were to be treated as a waste product, significant disposal costs would be realized through either coal ash landfill development or tipping fees at the municipal solid waste landfill.

***Facility Space Limitations*—**A DSI system is rather simple and requires lesser space for equipment than does a SDA system. Eielson Air Force Base (EAFB) recently installed new 120,000 lb/hr steam boilers which were designed with DSI to mitigate sulfate emissions. EAFB uses sodium bicarbonate as the sorbent, which they receive via rail from Solvay Chemical in Wyoming. The system includes two silos with storage capacity of 518 tons each for the sorbent. Each silo is 37 ft tall with a diameter of 21 ft and a 70 inch cone. The silos each hold a volume of 16,777 ft^3. EAFB's current rate of sorbent utilization is 1 lb of sorbent/1,600 lb of steam. At that rate, Aurora could expect a maximum use of 220 lb of sorbent/hr (350,000 lb steam/hr). The location of the injection point is at the outlet breaching of the boiler and the temperature of the flue gas at that point is 450°F. As previously discussed, 500°F at the injection point is optimal. While the silos do not occupy an extremely large area, the only available area on the Chena site would be in the northwest corner of the property. An adequate space exists in the northwest portion of the Chena site, but space for truck traffic to deliver the sorbent is extremely limited and may prevent actual truck movement in this area of the facility. Sorbent receiving would likely be sited north of the Chena River along with the coal receiving facilities. Sorbent would have to be received by rail or truck and conveyed across the river to storage silos on the south side of the river.

1.4 REVIEW OF SO_2 BACT DATABASE

The RACT/BACT/LAER (RBLC) Clearinghouse was searched again for this addendum (an original search was conducted and reported in the original BACT report) to identify similar sources with SO_2 BACT determinations within the past 10 years. The RBLC Clearinghouse lists 23 facilities with large (i.e., greater than 250 MMBtu/hr) coal-fired boilers with SO_2 BACT determinations and two facilities with small (i.e., less than 100 MMBtu/hr) coal-fired boilers with SO_2 BACT determinations. Table 1 summarizes the projects in the database search that are pertinent to the Chena Power Plant BACT Analysis. One additional facility is included, the Healy Power Plant, but was not identified in the RBLC search. When looking at reported performance at existing operations, one must acknowledge that the level of control claimed at existing facilities using SDA and DSI or as reported in the Clearinghouse database may not have actually been demonstrated by the facility and may not be achievable at the Chena facility. Additionally, other systems may have been installed that are not yet included in the RBLC Clearinghouse.

Ten of the 23 determinations for large boilers were for SDA and/or DSI systems, and the range of control reported for these determinations was:

- SDA: 0.06 to 0.10 lb/MMBtu (five facilities)
- DSI: 0.035 to 0.3 lb/MMBtu (four facilities)
- Combination SDA/DSI: 0.055 to 0.075 lb/MMBtu (three facilities)

Table 1. Summary of SO_2 BACT Permit Reviews

Search Criteria	Facility ID	Facility Name	Permit Issuance	Process Name	Control Method Description									Emission Limit
					Combustion Practices	Low Sulfur Coal	Wet FGD	Limestone Forced Oxidation	Dry FGD	FGD - Scrubber	Dry FGD - Spray Dry Adsorber	Limestone Injection[1]	Circulating Dry Scrubber	
Permit Date = 1/1/2007 to 10/24/2017 Process = coal-fired, >250 MMBtu/hr Pollutant Name = SO_2	AR-0094	John W. Turk Power Plant	11/5/2008	6,000 MMBtu/hr PRB sub-bituminous pulverized coal (PC) boiler							X			0.08 lb/MMBtu, 30-day average (0.065 lb/MMBtu when burning coal <= 0.45% by weight sulfur content. (PSD and Case-by-Case MACT permit decision.)
	AZ-0055	Navajo Generating Station	2/6/2012	3, 7,725 MMBtu/hr PC boilers						X				
	CA-1206	Stockton Cogen Company	9/16/2011	730 MMBtu/hr coal-fired circulating fluidized bed (CFB) boiler								X		70% removal (3-hr average)
	IA-0091	Ottumwa Generating Station	2/27/2007	6,370 MMBtu/hr coal-fired Boiler #1		X								1.2 lb/MMBtu, 3-hr rolling average (Wet FGD rejected at $29,797/ton (2007 dollar basis).)
	KY-0100	J.K. Smith Generating Station	4/9/2010	3,000 MMBtu/hr CFB boilers CFB1 and CFB2							X	X		0.075 lb/MMBtu, 30-day average (Based on PRB coal - 0.54% S; bituminous coal - 1.58% S; and 1.4 lb SO_2/MMBtu at wet FGD inlet.) Permit terminated due to legal challenge.
	MI-0389	Karn Weadock Generating Complex	12/29/2009	8,190 MMBtu/hr PRB coal or 50/50 blend PC boiler (fuel to meet 1.4 lb SO_2/MMBtu at FGD inlet)		X		X						0.06 lb/MMBtu, 30-day rolling average
	MI-0399	Detroit Edison--Monroe	12/21/2010	7,624 MMBtu/hr coal-fired Boiler Units 1, 2, 3 and 4			X							0.107 lb/MMBtu each, 24-hr rolling average
	MI-0400	Wolverine Power	6/29/2011	2, 3,030 MMBtu/hr, petcoke/coal-fired CFB Boilers (CFB1 & CFB2) (Excluding Startup & Shutdown)							X			0.06 lb/MMBtu, 30-day rolling average; excluding startup & shutdown
	MO-0077	Norborne Power Plant	2/22/2008	Supercritical PC boiler with steam turbine generator with a nominal net electric output of 689 MW					X					
	ND-0024	Spiritwood Station	9/14/2007	1,280 MMBtu/hr lignite coal-fired atmospheric CFB boiler							X	X		0.06 lb/MMBtu, 30-day rolling average; 98.7% removal for worst case 30-day lignite; 98.8% removal for worst case 24-hr lignite

Table 1. Summary of SO_2 BACT Permit Reviews (continued)

Search Criteria	Facility ID	Facility Name	Permit Issuance	Process Name	Control Method Description									Emission Limit
					Combustion Practices	Low Sulfur Coal	Wet FGD	Limestone Forced Oxidation	Dry FGD	FGD - Scrubber	Dry FGD - Spray Dry Adsorber	Limestone Injection[1]	Circulating Dry Scrubber	
	OH-0310	American Municipal Power Generating Station	10/8/2009	2, 5,191 MMBtu/hr, PC boilers			X							0.15 lb/MMBtu, 30-day rolling average; 0.184 lb/MMBtu, 24-hr rolling average; 0.2400 lb/MMBtu, 3-hr average Admin permit mod 10/09 to add Case-by-Case MACT for Boilers
	OH-0314	Smart Papers Holdings, LLC	1/31/2008	420 MMBtu/hr coal-fired pulverized dry bottom boiler and 249 MMBtu/hr coal-fired spreader stoker coal-fired boiler										1.7 lb/MMBtu
	OK-0118	Hugo Generating Station	2/9/2007	750 MW coal-fired steam EGU boiler (HU-Unit 2)			X							0.065 lb/MMBtu, 30-day rolling average
	PA-0257	Sunnyside Ethanol, LLC	5/7/2007	496.8 MMBtu/hr coal-fired CFB boiler					X			X		0.2 lb/MMBtu, 30-day rolling average
	TX-0554	Coleto Creek Unit 2	5/3/2010	6,670 MMBtu/hr PRB coal-fired Boiler Unit 2							X			0.06 lb/MMBtu, 30-day rolling average
	TX-0577	White Stallion Energy Center	12/16/2010	3,300 MMBtu/hr coal & pet coke-fired CFB Boiler							X			0.114 lb/MMBtu pet coke, 30-day rolling average; 0.086 lb/MMBtu, pet coke 12-mo rolling average; 0.063 lb/MMBtu coal, 30-day and 12-mo rolling average
	TX-0585	Tenaska Trailblazer Energy Center	12/30/2010	8,307 MMBtu/hr sub-bituminous coal-fired boiler			X							0.06 lb/MMBtu, 30-day rolling average
	TX-0593	Texas Clean Energy Project	12/28/2010	400 MW PRB coal-fired Integrated Gasification Combined Cycle power plant	X									10 ppm sulfur in syngas
	TX-0601	Gibbons Creek Steam Electric Station	10/28/2011	5,060 MMBtu/hr coal-fired boiler			X							1.2 lb/MMBtu
	UT-0070	Bonanza Power Plant Waste Coal Fired Unit	8/30/2007	2, 1,445 MMBtu/hr waste coal/bituminous blend-fired CFB boiler							X	X		0.055 lb/MMBtu, 30-day rolling average
	VA-0311	Virginia City Hybrid Energy Center	6/30/2008	2, 3,132 MMBtu/hr coal and coal refuse-fired CFB boilers (Sulfur content of coal/coal refuse to CFB boilers not to exceed 2.28% as-fired and 1.5% on annual basis)								X		0.035 lb/MMBtu, 3-hr average; 0.029 lb/MMBtu, 24-hr average; 0.022 lb/MMBtu, 30-day rolling average
	WY-0063	Wygen 3	2/5/2007	1,300 MMBtu/hr sub-bituminous coal-fired PC boiler					X					0.09 lb/MMBtu, 12-mo rolling average
	WY-0064	Dry Fork Station	10/15/2007	Coal-fired PC Boiler (ES1-01)									X	0.07 lb/MMBtu, 12-mo rolling average

Table 1. Summary of SO_2 BACT Permit Reviews (continued)

Search Criteria	Facility ID	Facility Name	Permit Issuance	Process Name	Control Method Description									Emission Limit
					Combustion Practices	Low Sulfur Coal	Wet FGD	Limestone Forced Oxidation	Dry FGD	FGD - Scrubber	Dry FGD - Spray Dry Adsorber	Limestone Injection[1]	Circulating Dry Scrubber	
	N/A (not in RBLC)	Golden Valley Electric Association – Healy Power Plant (HPP)	11/19/2012 Consent Decree and 4/14/2014 Minor Permit	2, existing PC-fired steam generators: a 25 MW Foster-Wheeler Boiler (Unit #1) and a 50 MW TRW Entrained Combustion System PC-fired steam generator (Unit #2).								X		Unit #1 (DSI system): - Improve existing DSI system no later than 9/30/2015 or 18 months after Unit #2 first fires coal after 11/19/2012 whichever is later. - After 1/1/2016, SO_2 emission limit of 0.30 lb/MMBtu, 30-day rolling average
											X			Unit #2 (SDA system): - SO_2 emission limit of 0.10 lb/MMBtu, 30-day rolling average
Permit Date = 1/1/2007 to 10/24/2017 Process = coal-fired, <100 MMBtu/hr Pollutant Name = SO_2	OH-0315	New Steel International Inc., Haverhill	5/6/2008	6, 60 MMBtu/hr waste heat, PC boilers							X			0.1760 lb/MMBtu as a rolling 3-hour average The facility is non-attainment for $PM_{2.5}$ and PSD for PM, PM_{10}, CO, NOx, SO_2, and VOC. A production rate restriction on the electric arc furnaces was requested to keel lead below PSD and Title V thresholds. PM_{10} was used as the limit in the permit. However, since $PM_{2.5}$ was used for all LAER determinations the limits were entered under $PM_{2.5}$ instead.
	VA-0309	Georgia Pacific Wood Products - Jarratt	5/15/2008	86.6 MMBtu/hr coal-fired Keeler Boiler	X	X								

1. Limestone Injection presumed to be equivalent to DSI.

It should be noted that SDA or DSI were required only on circulating fluidized bed (CFB) or pulverized coal (PC) boilers. In contrast, the Chena boilers are stoker boilers for which the boiler operation is quite different than a CFB or PC boiler and present unique retrofit challenges. In addition, the sizes of these units range from approximately 2 to 25 times larger than the large Chena boiler.

One small boiler was identified with an SDA system required to meet 0.1760 lb SO_2/MMBtu.

1.5 SUMMARY OF TECHNICAL FEASIBILITY

Regardless of the achievable level of control afforded by a dry scrubbing system, this control technology (SDA and DSI) is considered technically feasible for controlling SO_2 emissions from coal fired boilers, and the RBLC identifies several in use on larger coal-fired boilers. A detailed evaluation of constraints posed by site-specific factors, however, is needed before either specific technology can be considered feasible for use at the Chena facility. These detailed site-specific evaluations/design factors are beyond the scope of the current BACT analysis.

In the absence of a detailed control system design for Chena, a level of 0.10 lb SO_2/MMBtu was selected for SDA for the BACT analysis, which is comparable with that required for the Healy Unit #2. This represents a 74% reduction from Aurora's actual SO_2 emission rate of 0.39 lb/MMBtu. Independent discussions with SDA equipment vendors, however, indicate that vendors do not like to select design removal rates above 0.12 lb/MMBtu (equivalent to 70% removal). The Healy performance requirement is considered most relevant to Chena because the boilers at Healy are of similar size to Chena's and the coal feed is the same.

Selection of an appropriate design basis for a DSI system for Chena is much less straight forward. One primary reason is that DSI systems reported in the RBLC Clearinghouse are for lime injection into fluidized bed combustors, which are very different that the Chena stokers. A DSI system performance level of 0.30 lb SO_2/MMBtu has been specified for the Healy DSI system, representing a 23% reduction from average uncontrolled SO_2 emissions. Interestingly, the Technical Analysis Report (TAR) for Healy Permit AQ0173MSS0, which requires the facility to "improve" the DSI system performance currently on Healy Unit No. 1, specifies the improved emission rate of 0.30 lb SO_2/MMBtu. This

statement in the TAR, therefore, suggests that the original Healy DSI system was achieving less than 23% reduction of SO_2. Literature, however, commonly reports a lower end of DSI system performance at 40%, and discussions with vendors indicate that this level of removal (without knowing the exact coal used) is generally achievable using DSI. Because of discrepancies in reported DSI system performance, therefore, one could easily define DSI system performance when using Usibelli coal as less than 23% removal. For the current assessment, DSI system performance was selected to be between 0.23 and 0.30 lb SO_2/MMBtu (i.e., between 23% and 40% removal).

2 ECONOMIC EVALUATION OF SO_2 CONTROL OPTIONS

Despite the technical challenges described in Section 1 associated with installation of SDA or DSI at the Chena Power Plant, an economic evaluation was prepared for each technology under the assumption that these challenges could possibly be mitigated during a detailed design.

2.1 SDA ECONOMIC EVALUATION

Capital and operating costs associated with the installation of a SDA system are based on cost estimating procedures developed by U.S. EPA in the Coal Utility Environmental Cost (CUECost) tool. The CUECost tool is an Excel workbook (an interrelated set of spreadsheets) that produces rough-order-of-magnitude (ROM) cost estimates (+/-30% accuracy) of the installed capital and annualized operating costs for air pollution control systems installed on coal-fired power plants, including those to control emissions of SO_2. The SO_2 emission control technologies currently in the workbook include: limestone FGD system with forced oxidation (i.e., wet scrubber) and lime spray drying FGD system (i.e., dry scrubber).

The wet scrubber portion of the CUECost tool was used in the original BACT Analysis. The spray drying portion of the tool was used for this addendum and was used for two scenarios – control of the combined boiler exhaust and control of the large boiler exhaust only. The CUECost tool included the following site-specific information:

- Net Plant Heat Rate (Btu/kWhr) = 11,571
- Retrofit Factor = 2.0 (difficult)
- Coal ultimate and proximate analysis data and ash analysis data obtained from http://www.usibelli.com/Coal-data.php
- Site specific SO_2 emission rate
  - Combined exhaust = 0.39 lb SO_2/MMBtu
  - Large boiler only = 0.32 lb SO_2/MMBtu
- Reagent price is $215/ton delivered
- Cost basis = 2015
- SO_2 removal required = 74 percent
- Annual SO_2 removed based on full load at 8,760 hr/year

All other values used were default values.

No attempt was made to incorporate location-specific cost adjustment factors into the CUECost tool.

The cost-effectiveness of the SO_2 control system is calculated in the CUECost tool by dividing the total annual cost by the annual (potential) tons of pollutant removed. Costs were corrected to 2015 dollars using the Chemical Engineering Composite Price Index. Table 2 presents a summary of the CUECost inputs and calculation summary for the lime spray dryer scrubber.

Table 5 presents the cost effectiveness of the SDA technology (as well as the DSI technology discussed in the next section).

2.2 DSI ECONOMIC EVALUATION

Capital and operating costs associated with the installation of a DSI system are based on a DSI cost model developed by Sargent & Lundy and referred to as the IPM Model.[12] In developing the IPM Model, the authors reviewed cost data for several DSI systems and developed a relationship for the capital costs based on the sorbent feed rate. The Total Project Cost output by the IPM Model includes the base installed cost, the fixed operating and maintenance (O&M) cost, and the variable O&M cost. The base installed cost includes:

- All equipment
- Installation
- Buildings
- Foundations
- Electrical
- Retrofit difficulty factor
- Engineering and construction management

The Model uses 2012 pricing. Escalation is not included in the estimate.

[12] Ibid (Sargent & Lundy).

Table 2. CUECost Input and Calculation Summary for SDA

CUECost			
Coal Utility Environmental Cost			
Version 1, November 25, 1998 (revised 2-9-00 as CUECost3.xls)			
APC Technology Choices			
Description	**Units**	**Combined Exhaust**	**Large Boiler only**
FGD Process	Integer	2	2
(1 = LSFO, 2 = LSD)			
Particulate Control	Integer	1	1
(1 = Fabric Filter, 2 = ESP)			
INPUTS			
Description	**Units**	**Combined Exhaust**	**Large Boiler only**
General Plant Technical Inputs			
Location - State	Abbrev.	AK	AK
MW Equivalent of Flue Gas to Control System	MW	142.4	74.6
Net Plant Heat Rate	Btu/kWhr	11,571	11,571
Plant Capacity Factor	%	65%	65%
Total Air Downstream of Economizer	%	120%	120%
Air Heater Leakage	%	12%	12%
Air Heater Outlet Gas Temperature	°F	350	350
Inlet Air Temperature	°F	80	80
Ambient Absolute Pressure	In. of Hg	29.4	29.4
Pressure After Air Heater	In. of H2O	-12	-12
Moisture in Air	lb/lb dry air	0.013	0.013
Ash Split:			
Fly Ash	%	40%	40%
Bottom Ash	%	60%	60%
Seismic Zone	Integer	1	1
Retrofit Factor	Integer	2	2
(1.0 = new, 1.3 = medium, 1.6 = difficult)			
Select Coal	Integer	8	8
Is Selected Coal a Powder River Basin Coal?	Yes / No	No	No
Economic Inputs			
Cost Basis -Year Dollars	Year	2015	2015
Sevice Life (levelization period)	Years	10	10
Inflation Rate	%	3%	3%
After Tax Discount Rate (current $'s)	%	9%	9%
AFDC Rate (current $'s)	%	11%	11%
First-year Carrying Charge (current $'s)	%	22%	22%
Levelized Carrying Charge (current $'s)	%	17%	17%
First-year Carrying Charge (constant $'s)	%	16%	16%
Levelized Carrying Charge (constant $'s)	%	12%	12%
Sales Tax	%	6%	6%
Escalation Rates:			
Consumables (O&M)	%	3%	3%
Capital Costs:			
Is Chem. Eng. Cost Index available?	Yes / No	Yes	Yes
If "Yes" input cost basis CE Plant Index.	Integer	578.4	578.4
If "No" input escalation rate.	%	3%	3%
Construction Labor Rate	$/hr	$60	$60
Prime Contractor's Markup	%	3%	3%
Operating Labor Rate	$/hr	$63	$63
Power Cost	Mills/kWh	25	25
Steam Cost	$/1000 lbs	3.5	3.5

Note: 'MW Equivalent of Flue Gas to Control System' is heat input capacity converted to MW.

Lime Spray Dryer (LSD) Inputs			
SO2 Removal Required **(removal required to reach 0.1 lb/MMBtu)**	%	74%	69%
Adiabatic Saturation Temperature	°F	127	127
Flue Gas Approach to Saturation	°F	20	20
Spray Dryer Outlet Temperature	°F	147	147
Reagent Feed Ratio	Factor	0.76	0.70
(Mole CaO / Mole Inlet SO2)			
Recycle Rate	Factor	30	30
(lb recycle / lb lime feed)			
Recycle Slurry Solids Concentration	Wt. %	35%	35%
Number of Absorbers	Integer	1	1
(Max. Capacity = 300 MW per spray dryer)			
Absorber Material	Integer	1	1
(1 = alloy, 2 = RLCS)			
Spray Dryer Pressure Drop	in. H2O	5	5
Reagent Bulk Storage	Days	60	60
Reagent Cost (delivered)	$/ton	$215	$215
Dry Waste Disposal Cost	$/ton	$30	$30
Maintenance Factors by Area (% of Installed Cost)			
Reagent Feed	%	5%	5%
SO2 Removal	%	5%	5%
Flue Gas Handling	%	5%	5%
Waste / Byproduct	%	5%	5%
Support Equipment	%	5%	5%
Contingency by Area (% of Installed Cost)			
Reagent Feed	%	20%	20%
SO2 Removal	%	20%	20%
Flue Gas Handling	%	20%	20%
Waste / Byproduct	%	20%	20%
Support Equipment	%	20%	20%
General Facilities by Area (% of Installed Cost)			
Reagent Feed	%	10%	10%
SO2 Removal	%	10%	10%
Flue Gas Handling	%	10%	10%
Waste / Byproduct	%	10%	10%
Support Equipment	%	10%	10%
Engineering Fees by Area (% of Installed Cost)			
Reagent Feed	%	10%	10%
SO2 Removal	%	10%	10%
Flue Gas Handling	%	10%	10%
Waste / Byproduct	%	10%	10%
Support Equipment	%	10%	10%

SUMMARY OF COSTS

Description	Units	Combined Exhaust	Large Boiler only
APC Technologies			
SO2 Control		LSD	LSD
		Combined Exhaust	**Large Boiler only**
SO2 Control Costs		**LSD**	**LSD**
Total Capital Requirement (TCR)	$	$74,161,357	$62,173,057
	$/kW	$521	$833
First Year Costs			
Fixed O&M	$	$3,709,418	$2,767,988
	$/kW-Yr	26.05	37.10
	Mills/kWH	4.57	6.52
	$/ton SO2 removed	$9,289.4	$17,351.0
Variable O&M	$	$415,100	$203,435
	$/kW-Yr	2.92	2.73
	Mills/kWH	0.51	0.48
	$/ton SO2 removed	$1,039.5	$1,275.2
Fixed Charges	$	$16,537,983	$13,864,592
	$/kW-Yr	116.14	185.85
	Mills/kWH	20.40	32.64
	$/ton SO2 removed	$41,415.5	$86,909.6
TOTAL	$	$20,662,501	$16,836,015
	$/kW-Yr	145.10	225.68
	Mills/kWH	25.48	39.64
	$/ton SO2 removed	$51,744	$105,536
Levelized Current Dollars			
Fixed O&M	$/kW-Yr	30.11	42.89
	Mills/kWH	5.29	7.53
	$/ton SO2 removed	$10,737.6	$20,056.1
Variable O&M	$/kW-Yr	3.37	3.15
	Mills/kWH	0.59	0.55
	$/ton SO2 removed	$1,201.6	$1,474.0
Fixed Charges	$/kW-Yr	88.01	140.85
	Mills/kWH	15.46	24.74
	$/ton SO2 removed	$31,386.6	$65,864.3
TOTAL	$/kW-Yr	121.49	186.89
	Mills/kWH	21.34	32.82
	$/ton SO2 removed	$43,325.8	$87,394.4
Levelized Constant Dollars			
Fixed O&M	$/kW-Yr	26.05	37.10
	Mills/kWH	4.57	6.52
	$/ton SO2 removed	$9,289.4	$17,351.0
Variable O&M	$/kW-Yr	2.92	2.73
	Mills/kWH	0.51	0.48
	$/ton SO2 removed	$1,039.5	$1,275.2
Fixed Charges	$/kW-Yr	60.93	97.51
	Mills/kWH	15.20	24.32
	$/ton SO2 removed	$30,863.7	$64,767.1
TOTAL	$/kW-Yr	89.90	137.34
	Mills/kWH	20.29	31.32
	$/ton SO2 removed	$41,192.6	$83,393.3

The O&M cost includes:

- Fixed
  - Operating labor for the DSI system (two operators needed)
  - Maintenance materials and labor
  - Administrative labor
- Variable
  - Sorbent use
  - Waste production and disposable cost
  - Additional required power

The IPM Model used for this addendum included two equipment orientations: 1) sorbent injection into the combined boiler exhaust just immediately prior to the fabric filter, and 2) sorbent injection into the individual exhaust from the large boiler near the combustion zone. The IPM Model tool included the following site-specific information:

- Gross heat input
  - Combined = 486 MMBtu/hr
  - Large boiler = 255 MMBtu/hr
  - Small boilers = 77 MMBtu/hr each
- Retrofit Factor = 2.0 (difficult)
- Location Adjustment Factor = 2.2 (for Fairbanks, Alaska)
  - The location adjustment factor (LAF) is applied to the base installed cost and reflects the average statistical differences in normal labor, material, and equipment costs for similar facilities built in different geographical locations. The factor also makes allowances for weather, seismic, climatic, normal labor availability, labor productivity, life support/mobilization, and contractor's overhead and profit conditions. The factor does not reflect abnormal differences due to unique site consideration, such as historical preservation.[13] (The CUECost model has no way to accommodate this factor, and LAF was not applied for SDA.)
- Site specific SO_2 emission rate
  - 0.39 lb/MMBtu (combined)
  - 0.32 lb/MMBtu (large boiler only)
  - 0.49 lb/MMBtu (each small boiler)

[13] Programming Cost Estimates for Military Construction, UFC3-370-01, 6 June 2011.

- Cost Basis = 2015
- SO_2 removal required = 40 percent
- Annual SO_2 removed based on full load at 8,760 hr/year
- Minimum Normalized Stoichiometric Ratio (NSR) = 1.5 (to account for less than optimum mixing and residence time in the combined orientation; deposition in the individual orientation; and breaking the filter cake in all orientations.
- Sorbent price based on delivered price paid by Healy in 2015/2016

All other values used were default values.

The cost-effectiveness of the SO_2 control system is calculated in the IPM Model by dividing the total annualized operating cost by the annual (potential) tons of pollutant removed. Costs were corrected to 2015 dollars using the Chemical Engineering Composite Price Index. Table 3 and Table 4 present summaries of the IPM Model inputs and cost effectiveness calculation summaries for the DSI system.

Table 3. Annualized Cost Summary for DSI for the Combined Boiler Exhaust

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	142.4	<-- User Input
Retrofit Factor	B		2	<-- User Input (An "average" retrofit has a factor of 1.0.)
Gross Heat Rate	C	(Btu/kWh)	3,415	<-- User Input
SO2 Rate	D	(lb/MMBtu)	0.39	<-- User Input
Type of Coal	E		sub-bituminous	<-- User Input
Particulate Capture	F		Baghouse	<-- User Input
Milled Trona	G		**TRUE**	Based on in-line milling equipment
Removal Target	H	(%)	40	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with a Baghouse = 80% Milled Trona with Baghouse = 90%
Heat Input	J	(Btu/hr)	486,000,000	A*C*1000 or **User Input**
NSR	K		1.50	1.5 (to account for less than optimum mixing and residence time in the combined orientation and breaking the filter cake in all orientations)
Trona Feed Rate	M	(ton/hr)	0.34	(1.2011x10^-06)*K*A*C*D
Sorbent Waste Rate	N	(ton/hr)	0.246	(0.7387-0.00073696*H/K)*M Based on a final reaction product of Na2SO4 and unreacted dry sorbent as Na2CO3. Waste product adjusted for a maximum of 5% inert in the Trona sorbent.
Fly Ash Waste Rate Include in VOM?	P	(ton/hr)	0.90	(A*C)*Ash incoal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2, HHV = 11,000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2, HHV = 8,400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2, HHV = 7,200 **Usibelli Coal: Ash in Coal = 0.07; Boiler Ash Removal = 0.6; HHV = 7,560**
Aux Power Include in VOM?	Q	(%)	0.05	=if Milled Trona M*20/A else M*18/A
Trona Cost	R	($/ton)	451	<-- User Input (based on delivered price paid by Healy)
Waste Disposal Cost	S	($/ton)	50	<-- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more difficult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.09385	<-- User Input
Operating Labor Rate	U	($/hr)	63	<-- User Input (Labor cost including all benefits)
Location Adjusment Factor	LAF		2.2	Factor applied to Base Module Cost - Location Adjusment Factor for Fairbanks, AK from DoD Facilities Pricing Guide\2\2/, UFC 3-701-01, Change 8, July 2015.
IPM Model - Updates to Cost and Performance for APC Technologies - Dry Sorbent Injection for SO2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for USEPA.				
Capital Cost Calculation (2012 dollars)				**Comments**
Includes - Equipment, installation, building, foundations, electrical, and retrofit difficulty				
Base Module (BM) ($) Unmilled Trona = IF(M>25,(745000*B*M*LAF),(7500000*B*LAF*M^0.284) Milled Trona = IF(M>25,(820000*B*M*LAF),(8300000*B*LAF*M^0.284)		=	$ 26,915,857	Base DSI module includes all equipment from unloading to injection
Total Project Cost				
A1 = 5% of BM		=	$ 1,345,793	Engineering and construction management costs
A2 = 5% of BM		=	$ 1,345,793	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.
A3 = 5% of BM		=	$ 1,345,793	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3		=	$ 30,953,236	Capital, engineering, and construction costst subtotal
B1 = 5% of CECC		=	$ 1,547,662	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1		=	$ 32,500,898	Total project cost without AFUDC
B2 = 0% of (CECC + B1)		=	0	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2		**=**	**$ 32,500,898**	**Total project cost**

Note: 'Unit Size (Gross)' is heat input capacity converted to MW.

Table 3. Annualized Cost Summary for DSI for the Combined Boiler Exhaust (continued)

Direct Annual Costs			
Fixed O&M Cost			
FOMO ($/kW yr) = (2 additional operators)*(2080)*U/(A*1000)	=	$ 1.84	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	=	$ 0.95	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$ 0.07	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**=**	**$ 2.85**	**Total Fixed O&M costs**
Variable O&M Cost			
VOMR ($/MWh) = M*R/A	=	$ 1.08	Variable O&M costs for Trona reagent
VOMW ($/MWh) = (N+P)*S/A	=	$ 0.40	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) = Q*T*10	=	$ 0.045	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**=**	**$ 1.53**	
Indirect Annual Costs			
Overhead (80% of total operation and maintenance labor)	=	$ 324,909	
Administrative charges (2% of total capital investment)	=	$ 650,018	
Insurance (1% of total capital investment)	=	$ 325,009	
Property tax (1% of total capital investment)	=	$ 325,009	
Capital recovery	=	$ 5,289,521	
(16.275% of total capital investment: 10 yr at 10% interest)			
TOTAL INDIRECT ANNUAL OPERATING COSTS	=	**$ 6,914,466**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$ 9,227,624**	
Composite CE Index for 2012 (cost year of equation)	=	584.6	
Composite CE Index for 2015 (cost year of review)	=	578.4	
TOTAL ANNUALIZED OPERATING COSTS (2015 $)	**=**	**$ 9,129,760**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=	830	
SO_2 REMOVAL EFFICIENCY, %	=	40	
TOTAL SO_2 REMOVED, tons	=	332	
SO_2 COST-EFFECTIVENESS, $/ton removed	=	**$ 27,493**	

Table 4. Annualized Cost Summary for DSI for the Large Boiler Exhaust

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	74.6	<-- User Input
Retrofit Factor	B		2	<-- User Input (An "average" retrofit has a factor of 1.0.)
Gross Heat Rate	C	(Btu/kWh)	3,415	<-- User Input
SO2 Rate	D	(lb/MMBtu)	0.32	<-- User Input
Type of Coal	E		sub-bituminous	<-- User Input
Particulate Capture	F		Baghouse	<-- User Input
Milled Trona	G		**TRUE**	Based on in-line milling equipment
Removal Target	H	(%)	40	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with a Baghouse = 80% Milled Trona with Baghouse = 90%
Heat Input	J	(Btu/hr)	255,000,000	A*C*1000 or **User Input**
NSR	K		1.50	1.5 (to account for deposition in the individual orientation)
Trona Feed Rate	M	(ton/hr)	0.147	(1.2011x10^-06)*K*A*C*D
Sorbent Waste Rate	N	(ton/hr)	0.106	(0.7387-0.00073696*H/K)*M Based on a final reaction product of Na2SO4 and unreacted dry sorbent as Na2CO3. Waste product adjusted for a maximum of 5% inert in the Trona sorbent.
Fly Ash Waste Rate Include in VOM?	P	(ton/hr)	0.47	(A*C)*Ash incoal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2, HHV = 11,000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2, HHV = 8,400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2, HHV = 7,200 **Usibelli Coal: Ash in Coal = 0.07; Boiler Ash Removal = 0.6; HHV = 7,560**
Aux Power Include in VOM?	Q	(%)	0.04	=if Milled Trona M*20/A else M*18/A
Trona Cost	R	($/ton)	451	<-- User Input (based on delivered price paid by Healy)
Waste Disposal Cost	S	($/ton)	50	<-- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more difficult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.09385	<-- User Input
Operating Labor Rate	U	($/hr)	63	<-- User Input (Labor cost including all benefits)
Location Adjusment Factor	LAF		2.2	Factor applied to Base Module Cost - Location Adjusment Factor for Fairbanks, AK from DoD Facilities Pricing Guide\2\/2/, UFC 3-701-01, Change 8, July 2015.

IPM Model - Updates to Cost and Performance for APC Technologies - Dry Sorbent Injection for SO2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for USEPA.

Capital Cost Calculation (2012 dollars)			**Comments**
Includes - Equipment, installation, building, foundations, electrical, and retrofit difficulty			
Base Module (BM) ($) Unmilled Trona = IF(M>25,(745000*B*M*LAF),(7500000*B*LAF*M^0.284) Milled Trona = IF(M>25,(820000*B*M*LAF),(8300000*B*LAF*M^0.284)	=	$ 21,186,595	Base DSI module includes all equipment from unloading to injection
Total Project Cost			
A1 = 5% of BM	=	$ 1,059,330	Engineering and construction management costs
A2 = 5% of BM	=	$ 1,059,330	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.
A3 = 5% of BM	=	$ 1,059,330	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	$ 24,364,585	Capital, engineering, and construction coststs subtotal
B1 = 5% of CECC	=	$ 1,218,229	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	$ 25,582,814	Total project cost without AFUDC
B2 = 0% of (CECC + B1)	=	0	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**=**	**$ 25,582,814**	**Total project cost**

Note: 'Unit Size (Gross)' is heat input capacity converted to MW.

Direct Annual Costs				
Fixed O&M Cost				
FOMO ($/kW yr) = (2 additional operators)*(2080)*U/(A*1000)	=	$	3.51	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	=	$	1.42	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	0.12	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**=**	**$**	**5.06**	**Total Fixed O&M costs**
Variable O&M Cost				
VOMR ($/MWh) = M*R/A	=	$	0.889	Variable O&M costs for Trona reagent
VOMW ($/MWh) = (N+P)*S/A	=	$	0.39	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) = Q*T*10	=	$	0.037	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**=**	**$**	**1.31**	
Indirect Annual Costs				
Overhead (80% of total operation and maintenance labor)	=	$	301,717	
Administrative charges (2% of total capital investment)	=	$	511,656	
Insurance (1% of total capital investment)	=	$	255,828	
Property tax (1% of total capital investment)	=	$	255,828	
Capital recovery	=	$	4,163,603	
(16.275% of total capital investment: 10 yr at 10% interest)				
TOTAL INDIRECT ANNUAL OPERATING COSTS	=	**$**	**5,488,633**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**6,723,906**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2015 (cost year of review)	=		578.4	
TOTAL ANNUALIZED OPERATING COSTS (2015 $)	**=**	**$**	**6,652,596**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		357	
SO_2 REMOVAL EFFICIENCY, %	=		40	
TOTAL SO_2 REMOVED, tons	=		143	
SO_2 COST-EFFECTIVENESS, $/ton removed	=	**$**	**46,534**	

Table 5 presents a summary of the cost effectiveness of all SO_2 control options considered, including the wet scrubber considered in the original BACT Analysis. As seen in the individual cost model spreadsheets, the model-derived cost-effectiveness values are based on the potential SO_2 emissions from the Chena boilers. The combined SO_2 emission rate from all four boilers is equal to 814.5 tons/yr (potential) and 700 tons/yr (actual). The value for actual emissions is based 1.9 tons SO_2 per day as specified in the State Implementation Plan (SIP). Therefore, to derive cost-effectiveness values based on actual expected SO_2 reductions, the cost-effectiveness values output by the cost models were adjusted by the ratio of actual emissions to potential emissions.

Table 5 presents the calculated SO_2 removal cost effectiveness on both a potential emission reduction and actual emission reduction basis. These values are not considered cost effective for the retrofit options at Chena Power Plant.

Table 5. Summary of Cost Effectiveness of SO_2 Control Options

Rank	Control Option	Control Orientation	Cost Effectiveness ($ per year/ ton per year removed		Expected SO_2 Emission Rate (lb/MMBtu)
			Potential	Actual	
1	Low sulfur coal	combined exhaust	(already used)		0.39
2	Dry scrubber – DSI	combined exhaust	27,493	31,990	0.23 (40% removal)
3	Dry scrubber – SDA	combined exhaust	41,193	47,931	0.10 (74% removal)
4	Dry scrubber – DSI	large boiler only	46,534	54,146	0.19 (40% removal)
5	Wet scrubber	combined exhaust	75,672	88,050	0.20 (50% removal)
6	Dry scrubber – SDA	large boiler only	83,393	97,034	0.10 (69% removal)

3 DISCUSSION OF SITE-SPECIFIC TECHNICAL, ENVIRONMENTAL, AND ENERGY ASPECTS OF DRY SCRUBBING TECHNOLOGY USE AT CHENA POWER PLANT

3.1 SUMMARY OF TECHNICAL FEATURES AND CHALLENGES

Table 6 presents a summary of some technical features of SDA and DSI technologies evaluated herein and some challenges associated with their potential use at Chena. Section 1 of this report identified several SDA and DSI applications for coal-fired boilers. The quality of the information varies considerably, and the information acquired was used as best as possible to hypothesize performance expectations from each evaluated technology. Nonetheless, no true assurances exist that the evaluated technologies will actually perform as stated when applied to the Chena facility. While the technical concepts are valid, demonstration of the technology employed as retrofit technology on units and equipment orientations such as those observed at the Chena facility cannot reliably be predicted, thus raising doubts over the accuracy of technology transfer, particularly for sorbent injection. Perhaps the best example of this uncertainty can be found when reviewing the history of the DSI system operation at the Healy Power Plant in Healy, AK. The subject of a Consent Decree, Healy was ordered to "improve" the DSI system in use on Unit No. 1 to achieve a controlled SO_2 emission rate of 0.30 lb/MMBtu. Even with extensive testing under the US Department of Energy Clean Coal program, this marginal mandated performance level is indicative of technological uncertainties associated with retrofit technology applied to control coal-fired boiler emissions.

Coupled with the technological uncertainties associated with these technologies applied as a retrofit solution are other factors that obscure the practicality of applying retrofit dry scrubber technology at the Chena facility. One of these factors, the economics of the technologies, was discussed in detail in Section 2 of this report and led to the observation that application of SDA or DSI at Chena was not a cost-effective means to reduce SO_2 emissions. Other factors, discussed in the following sections, include:

- Facility location limitations
- Environmental considerations
- Energy considerations

Table 6. Summary of Technical Challenges Associated with Dry SO_2 Scrubbing at Chena Power Plant

Factor	Spray Dry Absorber Technology	Dry Sorbent Injection Technology
Demonstrated use under conditions similar to Chena Plant	1. Spray dry absorber technology is available and used to reduce SO_2 emissions from coal-fired boiler flue gas streams. 2.The U.S. EPA's air pollution control cost manual indicates that SDA technology can be reduce SO_2 by 50% up to over 90%. Finding a suitable outlet for the particulate captured in the fabric filter following dry scrubbing is an important consideration to the feasibility of this option.	1. Dry sorbent injection is becoming more prevalent for reducing acid gas concentrations in coal-fired boiler flue gas streams. 2. Although DSI technology is discussed in the industry, the only DSI systems presented in the RBLC Clearinghouse are lime/limestone injection systems into fluidized bed combustors. No DSI systems are listed when the boiler is a stoker, as at Chena. 3. Sorbent injection into the duct work downstream of the coal combustion zone is also becoming more prevalent in the industry, as reported by equipment vendors. No such systems, however, are presented in the RBLC Clearinghouse.
Technical considerations	1. Depending on equipment orientation, a SDA system would lower the flue gas temperature, which could then cause plugging of the downstream fabric filter. 2. A SDA system placed upstream of the fabric filters would potentially contaminate the ash and cause the loss of a useable by-product. 3. A SDA system would require gas reheating to prevent plugging in the fabric filter, thus increasing station service load. 4. The temperature of water used to prepare the lime slurry can impact the hydrated lime reactivity. Adequate facilities must be included (indoors) to prevent issues associated with slurry preparation, delivery, and use. 5.The pulse jet cleaning system in the existing fabric filter will periodically break the filter cake, thus temporarily reducing the additional sorbent reaction time with SO_2 and ultimately reducing the overall SO_2 removal that can be achieved.	1. The existing duct work at Chena is very complicated and winding. Sorbent injection into a section of combined flue gas would have less than optimum mixing and less than 0.2 seconds of residence time prior to entering the fabric filter. These two situations will increase the sorbent consumption rate by reducing sorbent utilization. 2. Sorbent injection into the large boiler alone would provide adequate mixing time, but the flue gas would continue through seven turns in which sorbent loss through deposition on the interior duct work could occur, thus increasing sorbent consumption. 3.The pulse jet cleaning system in the existing fabric filter will periodically break the filter cake, thus temporarily reducing the additional sorbent reaction time with SO_2 and ultimately reducing the overall SO_2 removal that can be achieved. 4. Use of sorbent materials may render the collected ash no longer suitable for use as a fill material. The current beneficial use of collected ash as a fill material would have to be replaced with landfill disposal of the collected PM.

Table 6. Summary of Technical Challenges Associated with Dry SO_2 Scrubbing at Chena Power Plant (continued)

Factor	Spray Dry Absorber Technology	Dry Sorbent Injection Technology
Structural considerations	1. The structural stability of the existing ash silo would have to be improved prior to storing any additional PM. 2. Any system placed downstream of the existing fabric filter would necessitate major structural modifications to the existing filter housing to alter the exhaust configuration of the treated flue gas from a monovent, roof monitor arrangement to a gas duct section that delivers gas to the dry scrubber system.	
Operational considerations	1. A SDA system would require additional fans to overcome the increased distance needed to convey the flue gas. The entire air emissions control systems would need to be rebalanced as well. The existing system potentially may not meet design requirements for baghouse air flow.	1. The history of DSI operation at the Healy facility of GVEA has been anything but stable. The need to retrofit the system on two different occasions draws into question the reliability of the DSI technology.
	2. The Chena boilers are reaching the end of their useful lives. A life extension study commissioned by Aurora determined that Chena operations could be extended to the year 2030 with expenditure of significant capital. An add-on emission control program aimed at reducing SO_2 emissions over a 10-year period represents an unwise capital expenditure at this time. 3. The U.S. Corps of Engineers estimates that additional construction and operating costs are incurred for projects in Alaska when compared to mainland US. These considerations are difficult to assess in an analysis such as this BACT. 4. .A dry scrubber placed at the outlet of the existing fabric filter would require re-heating the exhaust gases to an optimum temperature; this would reduce steam available for power generation, heating, or station service. A second fabric filter would be then needed to remove the particulate matter formed during scrubbing. 5. The Trona or sodium bicarbonate reagent mill would be required to produce a uniformly-sized sorbent particle prior to use. 6. Reagent receiving and processing would likely require construction of building(s) north of the Chena River and a conveyor over the Chena River. Raw and processed materials would need to be conveyed over relatively long distances. 7. The PM collected in the fabric filter may become a waste product and no longer able to be used as fill. 8. The PM collected in the fabric filter may require pre-treatment prior to disposal as a solid waste.	

Table 6. Summary of Technical Challenges Associated with Dry SO_2 Scrubbing at Chena Power Plant (continued)

Factor	Spray Dry Absorber Technology	Dry Sorbent Injection Technology
Availability of infrastructure and space for equipment	1. A minimal amount of open space is available at the Chena facility to house additional equipment needed to support dry scrubbing technology.	
	2. The location of a reagent storage area for an SDA system will need to be determined. 3. A preliminary estimate, based on a similarly-sized facility in Colorado, is that the spray tower will need to be at least 40 ft in diameter. The only available space at the Chena facility for this tower would be in the northwest corner of the facility. 4. The flue gas would need to be rerouted approximately 250 ft to the location of the spray tower and then return another 250 ft to the inlet of the fabric filter. This gas rerouting would be needed whether the SDA was oriented as a combined flue gas treatment system or one devoted only to the large boiler. Space for additional fans would then be needed. 5. Availability of land area for the reagent silos and slurry preparation is uncertain.	2. The short duct run after combination of flue gases makes sorbent inject extremely difficult and leads to poor mixing and short residence time. 3. An area of approximately 50 ft x 50 ft would be needed to house the sorbent receiving and storage area. This area would need to be located in the northwest corner of the facility. This area of the facility has minimal truck traffic at present, and routine deliveries of sorbent by truck would disrupt the normal operations in the area.

These factors are discussed in the following sections. These factors also were discussed in the original BACT Analysis, and some of the discussion presented below is taken from the original analysis.

3.2 LOCATION CONSIDERATIONS

Several issues related to space limitations at Chena were presented in Section 1 or this report. An important aspect of operating on an older, small industrial site is the ability to actually place additional equipment needed to operate add-on control equipment. The SDA and DSI technologies require installation of silos for reagent storage, facilities for preparing the sorbent for treatment of the flue gas, and the technology itself must be erected in available space. The congested nature of the existing Chena Power Plant site is such that the retrofit installation costs are likely to be higher than those estimated and presented in the cost tables provided earlier. Additionally, lack of available space on site could make installation of additional equipment completely infeasible. This limitation would not be completely understood prior to preliminary design of any identified system.

Each of the identified SO_2 technologies also requires routine delivery of reagents to operate the system and will require removal of residues produced by the process. The congested nature of the Chena facility makes on-site truck traffic patterns somewhat problematic. Additionally, Fairbanks is approximately 400 miles from Anchorage, which is a logical location for origination of raw materials. Delivery of necessary sorbents over potentially icy roadways may interrupt raw material deliveries to the point where interruptions in plant operations could occur. The hazardous driving conditions also may cause the transportation costs for raw materials or process equipment to be greater than presented in the cost sheets, thereby causing the cost effectiveness of control to be a larger value than calculated.

Climate considerations factor into the BACT evaluation in two ways: 1) climate causes the costs to become inflated due to the need for additional insulation, heated vessels, and heat tracing, and 2) climate affects the ability of the precursor emissions from the Chena Power Plant to react in the atmosphere and form $PM_{2.5}$. However, no site factors are included in the SDA control cost calculations. Thus, the SDA SO_2 control costs, while already extremely high, may be underestimated. The atmospheric factor, which may limit atmospheric reaction rates, is briefly discussed in the next section on environmental considerations.

3.3 ENVIRONMENTAL CONSIDERATIONS

Environmental factors must be considered in a BACT evaluation. With respect to nonattainment BACT, precursor control options that are determined to be economically feasible may not yield the desired objective of improving $PM_{2.5}$ air quality. (This statement is true even though none of the control options evaluated in this BACT evaluation were found to be economically feasible.) A rash conclusion to implement a (economically feasible) precursor control as BACT may in fact produce insignificant environmental benefits and at the same time produce adverse energy or environmental impacts. The environmental topics are discussed below, and energy considerations in the following section. Much of the following discussion was presented in the original BACT Analysis.

The rationale for ensuring that benefits of a precursor control option are indeed real and significant is founded in the Clean Air Act (CAA). CAA section 189(e) explicitly requires that the control requirements applicable for major stationary sources of direct $PM_{2.5}$ emissions must also apply to major stationary sources of $PM_{2.5}$ precursors, unless the state provides a

demonstration that emissions of a particular precursor from major stationary sources do not contribute significantly to levels that exceed the standard in the nonattainment area of concern. Thus, the statute generally requires control of all $PM_{2.5}$ precursors in a nonattainment area, but it provides an express exception applicable to major stationary sources in such areas if an appropriate demonstration is made.[14]

A key conclusion derived by looking at the chemical mass balance (CMB) evaluations for PM filters collected in the Fairbanks North Star Borough (FNSB) is that control of Chena Power Plant $PM_{2.5}$ precursors will not provide significant reduction of ambient $PM_{2.5}$. This conclusion can easily be validated by looking solely at the wood smoke contribution and comparing it to the $PM_{2.5}$ standard. As is seen on many episode days, the standard is exceeded solely due to contribution from wood smoke, while the impact of sulfates on episode days is minor.

Although the CMB results included in the SIP provide some insight into establishing source contributions in the FNSB, no straightforward procedures can be used to determine a specific source contribution to ambient $PM_{2.5}$ concentrations and, by extension, the air quality improvements in $PM_{2.5}$ air quality should one or more control measures be implemented at the Chena Power Plant. Because no one procedure answers every question one may have, a variety of procedures are often employed. This is a key issue that relates the magnitude of reductions in daily precursor emissions to commensurate reductions in $PM_{2.5}$ concentrations. In many cases, indirect procedures must be employed to estimate air quality benefits resulting from installation of precursor emission controls. For example, DSI (the SO_2 control option identified herein that has the best cost-effectiveness) was estimated to be able to achieve a 40 percent reduction in SO_2 emissions from the Chena Power Plant boilers. As provided in the background information for the ADEC SIP, on average, Chena Power Plant boilers emitted 1.9 ton/day of SO_2 in 2015 on days when the $PM_{2.5}$ standard was exceeded.[15] Thus, application of DSI at Chena would result in an average SO_2 reduction of 0.76 ton/day.

[14] Federal Register, Volume 81, page 58091, August 24, 2016, 40 CFR Parts 50, 51, and 93, Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements; Final Rule.

[15] ADEC, Amendments to: State Air Quality Control Plan Volume II: Analysis of Problems, Control Actions; Section III: Area-wide Pollutant Control Program; D: Particulate Matter; 5: Fairbanks North Star Borough $PM_{2.5}$ Control Plan, Section 5.06, page III.D.5.6-27.

This reduction represents only 6.2 percent of the estimated NOx and SO_2 nonattainment area-wide emissions, respectively, estimated to occur on $PM_{2.5}$ episode days in 2008.

ADEC included CMB results in the SIP to provide some insight into establishing source contributions in the FNSB.[16] The CMB analysis estimated a maximum sulfate contribution of 28.8 micrograms per cubic meter ($\mu g/m^3$) (at most) in downtown Fairbanks on high $PM_{2.5}$ concentration days between 2005 and 2013. Assuming that all of the precursor emission reductions noted above for Chena Power Plant culminate in the same level of ambient $PM_{2.5}$ reductions, use of DSI technologies at Chena would benefit ambient air quality in downtown Fairbanks by only 1.8 $\mu g/m^3$ for sulfates (i.e., 28.8 μg sulfate/m^3 times 6.2 percent reduction in daily SO_2 emissions). The improvements on an average basis would be about half these amounts.

Another environmental factor impacting the true effectiveness of a control option is the atmospheric reaction process that leads to conversion of precursor emissions to $PM_{2.5}$. Three major issues must be considered when evaluating the Chena Power Plant's contribution to $PM_{2.5}$ levels within the FNSB air basin: 1) precursor reaction chemistry in arctic wintertime conditions when exceedances of the $PM_{2.5}$ NAAQS occur, 2) possible increases in nitrate formation as ammonium ions become available, and 3) transport and dispersion of the Chena Power Plant boiler stack plume above and beyond the capped inversion layer that encapsulates the FNSB air basin causing accumulation of ground-level $PM_{2.5}$ within the air basin.

Formation of secondary $PM_{2.5}$ depends on numerous factors including the concentrations of precursors; the concentrations of other gaseous reactive species; atmospheric conditions including solar radiation, temperature, and relative humidity; and the interactions of precursors with preexisting particles and with cloud or fog droplets. The relative contribution to ambient $PM_{2.5}$ concentrations from each precursor pollutant varies by

[16] ADEC, Amendments to: State Air Quality Control Plan SIP, Vol. III: Appendix III.D.5.7, Appendix to Volume II. Analysis of Problems, Control Actions; Section III. Area-wide Pollutant Control Program; D. Particulate Matter; 5. Fairbanks North Star Borough $PM_{2.5}$ Control Plan, December 24, 2014, page III.D.5.7-66.

climatological area. The relative effect of reducing emissions of these pollutants is also highly variable.[17]

Sulfates are typically formed in the atmosphere by formation of sulfuric acid from SO_2 that subsequently reacts with ammonia to form ammonium sulfate. There are three different pathways for the transformation of SO_2 to sulfuric acid[18:]

1. Gaseous SO_2 can be oxidized by the hydroxyl radical (OH) to create sulfuric acid. This gaseous SO_2 oxidation reaction occurs slowly and only in the daytime.

2. SO_2 can dissolve in cloud water (or fog or rainwater), and there it can be oxidized to sulfuric acid by a variety of oxidants, or through catalysis by transition metals such as manganese or iron. If ammonia is present and taken up by the water droplet, then ammonium sulfate will form as a precipitate in the water droplet.

3. SO_2 can be oxidized in reactions in the particle-bound water in the aerosol particles themselves. This process takes place continuously, but only produces appreciable sulfate in alkaline (dust, sea salt) coarse particles.

These climatological conditions that are conducive to sulfate formation from transformation of SO_2 are not consistent with the conditions that typically generate high $PM_{2.5}$ concentrations in the FNSB.

Some researchers have reported an increase in nitrate formation associated with ambient SO_2 reductions. This association is strongest in low temperature areas of low humidity and exists because additional ammonium ions will become available for reaction with NOx emissions.[19] Although the net $PM_{2.5}$ concentration will likely be lower after SO_2 reductions, a linear reduction of the ambient $PM_{2.5}$ concentration is not

[17] Federal Register, Volume 73, page 28325, May 16, 2008, 40 CFR Parts 51 and 52, Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$).
[18] NARSTO (2004) Particulate Matter Science for Policy Makers: A NARSTO Assessment. P. McMurry, M. Shepherd, and J. Vickery, eds. Cambridge University Press, Cambridge, England. ISBN 0 52 1842875.
[19] Ibid (NARSTO).

expected, and less $PM_{2.5}$ reduction will be observed than expected because of the increase in the nitrate concentration.

An issue also arises in the FNSB related to the dispersion of precursor emissions from the Chena Power Plant boiler stack and the ability of the dispersed emissions to actually impact the ambient air quality monitors. It has been observed, and it is reasonable to expect, that the boiler stack plume is carried above the winter inversion layer. As such, transport of the precursor pollutants occurs above the inversion layer, where the concentrations of the pollutants can be transported and dispersed by the stronger aloft winds. In addition, the Fairbanks $PM_{2.5}$ Source Apportionment Research Study[20] concluded that dominant aloft wind direction during $PM_{2.5}$ episodes is from the northeast, which would transport the Chena Power Plant emissions away from the ambient air quality monitors located in downtown Fairbanks and North Pole. Figure 2 presents a photograph showing the Chena Power Plant boiler stack exhaust plume height well above the inversion layer. The original BACT Analysis presented an evaluation of Chena coal consumption on high $PM_{2.5}$ concentration days between 2013 and 2015 and revealed a very poor (or no) correlation between Chena Power Plant coal consumption and observed ambient $PM_{2.5}$ levels. This poor correlation is believed to be due to plume entrapment above the wintertime inversion layer.

The poor correlations reported in the original BACT Analysis indicate that changes in Chena Power Plant emissions do not explain the majority of the changes in ambient $PM_{2.5}$ levels. Because the Chena Power Plant emissions are not seemingly influencing the ambient $PM_{2.5}$ concentrations to any significant extent, the ambient levels must be the result of other emission sources in the FNSB.

[20] The Fairbanks, Alaska $PM_{2.5}$ Source Apportionment Research Study Winters 2005/2006-2012/2013, and Summer 2012; Final Report, Amendments 6 and 7, December 23, 2013, Tony J. Ward, Ph.D., University of Montana – Missoula , Center for Environmental Health Sciences.



Figure 2. Chena Power Plant exhaust plume.[21]

[21] The exhaust from the Aurora Energy power plant breaks through an inversion layer as seen from the Hagelbarger Road pullout off the Steese Highway. Photo credits: Frank DeGenova, January 30, 2008, http://marcvaldez.blogspot.com/2008/05/wintertime-smokestack-plumes-in.html, accessed December 22, 2017.

This observation can be further illustrated using the following example for the highest $PM_{2.5}$ day (early January) in 2015 at downtown Fairbanks monitors when Chena Power Plant coal consumption was at its greatest rate (2.2 million pounds/day). If this was during one of the coldest days, then the Chena Power Plant impact at ground level would have been less than on other days because: 1) the buoyancy term for the Chena Power Plant boiler plume would be at its greatest because the temperature differential between stack and ambient air temperatures would have been greatest, and 2) the momentum term for the boiler plume would also have been at its greatest because the exhaust gas flow rate would be greater than at lesser coal combustion rates. Because the impact of Chena Power Plant emissions would likely have been less on this episode day than other days, the $PM_{2.5}$ mass on the filters in question would had to have been contributed by other sources in the FNSB.

To summarize these environmental considerations related to photochemistry and precursor transport within the FNSB, the U.S. EPA makes the following corroborating points:

> "Major stationary sources with elevated stacks emit most of their precursors into the extremely stable atmosphere present during wintertime pollution events. Only a fraction of the elevated plumes returns to ground level in the FNSB where air quality monitors are located and much less than might be expected in most parts of the lower 48 states."[22]

In conclusion, and as noted earlier herein, use of DSI technologies at Chena is estimated to benefit ambient $PM_{2.5}$ air quality in downtown Fairbanks by only 1.8 $\mu g/m^3$ at the most due to reduction of ambient sulfates (i.e., 28.8 μg sulfate/m^3 times 6.28 percent reduction in daily SO_2 emissions). The actual improvement will likely be less due to the environmental considerations noted herein. The maximum estimated sulfate improvements in $PM_{2.5}$ air quality presented here are only slightly above the U.S. EPA-recommended 24-hour significant level of 1.3 $\mu g/m^3$ as presented in the recent Draft Precursor Guidance and could actually be less than the significant level. This reduction would possibly be accompanied by other increases in fuel combustion emissions, production

[22] Federal Register, Volume 82, page 9043, February 2, 2017, Air Plan Approval; AK, Fairbanks North Star Borough; 2006 $PM_{2.5}$ Moderate Area Plan, Proposed Rule.

of a brown NOx cloud in the Chena plant stack, and elimination of the beneficial use of fly ash collected at the plant as fill material. These observations indicate that the environmental benefit of installing SO_2 controls at Chena Power Plant will produce no noticeable improvement in ambient $PM_{2.5}$ air quality and may produce negative associated environmental impacts.

3.4 ENERGY CONSIDERATIONS

Retrofit BACT as a means to reduce the pollutant load in an air basin must necessarily look at the effect that employing BACT on a specific source would have on other sources in the air basin and whether this effect would negatively impact the air quality improvement that is presumed to occur when BACT is employed. The original BACT Analysis presented a detailed discussion of energy considerations arises from the use of add-on air pollution control equipment. The reader is referred to that document for additional information regarding energy considerations for additional fuel and electricity consumption.

3.5 SUMMARY OF ENVIRONMENTAL AND ENERGY CONSIDERATIONS

The environmental considerations associated with installation of SO_2 controls on the Chena Power Plant produce uncertain assurances that any improvement in FNSB air quality will result. In fact, the data suggest that insignificant environmental improvements at best could occur. The energy considerations point to a likely lack of an air quality benefit in FNSB in the event that SO_2 controls are implemented at Chena Power Plant. In fact, such implementation could actually increase the air pollutant load in FNSB from sources more likely to produce a $PM_{2.5}$ ambient impact than Chena Power Plant.

4 ANALYSIS OF ASPECTS RELATED TO BACT

The supplemental information presented herein supports and enhances the SO_2 BACT determination presented in the original BACT Analysis. The previous sections of this supplement analyzed the several aspects that must be considered in a BACT determination, those being technical feasibility, economics, environment, and energy. This analysis yielded the following findings:

1. The technical feasibility of employing add-on SO_2 controls at Chena is highly questionable due to lack of available space at the facility for the equipment needed to scrub the flue gas as well as raw material receiving and processing equipment. Furthermore, the degree of control afforded by SDA and DSI technology is highly variable and difficult to define for conditions existing at Chena.

2. The economic analysis shows that use of SDA or DSI technology for SO_2 control is does not make economic sense as a retrofit option at Chena Power Plant.

3. The environmental considerations demonstrated that no significant ambient $PM_{2.5}$ improvement would be obtained by requiring SO_2 controls on Chena Power Plant. ADEC also recognizes that controlling direct $PM_{2.5}$ emissions (such as from wood stoves) is 13 times more effective at reducing ambient $PM_{2.5}$ concentrations than controlling precursor air pollutants that produce secondary $PM_{2.5}$. Furthermore, the actual ambient $PM_{2.5}$ benefit that can be achieved by reducing SO_2 emissions is extremely uncertain and difficult to calculate.

4. From an energy standpoint, installing an add-on SO_2 control device would increase the parasitic load at the Chena Power Plant. Loss of this energy output would require supplemental energy consumption at other sources within the FNSB or acquired through the grid from Anchorage to compensate for this parasitic load. This supplemental energy consumption at other sources may actually produce an increase in direct $PM_{2.5}$ emissions if the lost capacity were to be offset by fuel consumption for sources such as wood-burning stoves or oil-fired boilers, which tend to emit more direct $PM_{2.5}$ than Chena Power Plant, and at lower elevations. Furthermore, ADEC has already concluded, based on CMB

evaluations of PM filters in the FNSB, that these lower level sources are the more significant contributors to ambient $PM_{2.5}$ concentrations. Thus, the energy impacts of requiring SO_2 controls on Chena Power Plant could potentially have the exact opposite effect as desired and produce increases in ambient $PM_{2.5}$ concentrations in the FNSB.

4.1 DETERMINATION OF BACT FOR SO_2

Alaska coal has very low sulfur content, and uncontrolled sulfur emissions are four times lower than at a plant burning "low sulfur coal" in the lower 48 states.[23] The result is that the cost-effectiveness of SO_2 control technologies is poorer in Alaska than the lower 48 states. Current SO_2 emission rates from the Chena Power Plant are comparable to those identified as BACT in the most recent BACT determinations included in the RBLC database.

Therefore, as concluded in the original BACT Analysis, BACT for SO_2 emissions from Chena Power Plant is determined to be the continued use of low-sulfur coal.

[23] ADEC, Amendments to: State Air Quality Control Plan SIP, Vol. III: Appendix III.D.5.7, Appendix to Volume II. Analysis of Problems, Control Actions; Section III. Area-wide Pollutant Control Program; D. Particulate Matter; 5. Fairbanks North Star Borough $PM_{2.5}$ Control Plan, December 24, 2014, page III.D.5.7-78.

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

DIVISION OF AIR QUALITY
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CERTIFIED MAIL: 7017 3040 0000 4359 5189
Return Receipt Requested

September 13, 2018

David Fish, Environmental Manager
Aurora Energy, LLC
100 Cushman St., Ste. 210
Fairbanks, AK 99701

Subject: Second request for additional information for the Best Available Control Technology Technical Memorandum from Aurora Energy, LLC (Aurora) for the Chena Power Plant by November 1, 2018

Dear Mr. Fish:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that the Aurora Chena Power Plant and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to Serious Non-Attainment Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measures (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as the Aurora Chena Power Plant. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analysis is a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an email to Mr. Fish at Aurora on May 11, 2017 notifying him of the reclassification to Serious and

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 [illegible]

[2] [illegible] Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(4)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.

[3] [illegible] Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.

included a request for the BACT analysis to be completed by August 8, 2017. The BACT analysis from Aurora, which included emission units found in Operating Permits AQ0315TVP03 Revision 1, was submitted by email to the Department on March 20, 2017.

On March 22, 2018, ADEC released a preliminary draft of the BACT determination for the Chena Power Plant for public discussion on its website at: http://dec.alaska.gov/air/anpms/comm/nitter/fbks-pm2.5-source-sp-chenapp.pdf. As indicated in the release, this document is a work in progress. ADEC received additional information from the EPA on the preliminary draft BACT determination and expects to make changes to the determination based upon this input. Therefore, ADEC is requesting additional information from Aurora to assist it in making a legally and practicably enforceable BACT determination for the source.

Specifically, ADEC requests that Aurora review the cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the cost effectiveness calculations and indicates that the model is intended to calculate estimated total project cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent and the gross generating capacity of the plant. Please use this spreadsheet to calculate the cost effectiveness of SO_2 removal in dollars per ton and identify all assumptions and technical justifications used in the analysis.

If ADEC does not receive a response to this information request by November 1, 2018, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facility's infrastructure and without additional information, may select a more stringent BACT for your facility in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public review along with any precursor demonstrations and RACM analyses before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes a final BACT determination for Aurora, it must include the determination in Alaska's Serious SIP which ultimately requires approval by EPA.[4] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented prior to June 9, 2021 – 4 years after reclassification.[5]

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM) consideration. MSMs will be a required element of the state implementation plan if the State applies for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

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[4] https://www.govinfo.gov/app/details/CFR-2013-title42-vol3/CFR-2013-title42-vol3-sec7513a (accessed 2013 title42-vol3-sec7513a).pdf?packageId=CFR-2013-title42-vol3-sec7513a

[5] 40 CFR §51.1019(d)

ADEC appreciates the cooperation that we've received from Aurora. ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Denise Koch, Director
Division of Air Quality

Enclosures:

September 10, 2018	ADEC Request for Additional Information for Chena Power Plant BACT Analysis
May 21, 2018	EPA Comments on ADEC Preliminary Draft Serious SIP Development Materials for the Fairbanks Serious PM-2.5 nonattainment Area
November 16, 2017	ADEC Request for Additional Information for Aurora Energy LLC, BACT Analysis
November 15, 2017	EPA Aurora Energy – Chena Power Plant BACT Analysis Review Comments
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for Aurora Energy, LLC

cc: Larry Hartig, ADEC/Commissioner's Office
Alice Edwards, ADEC/Commissioner's Office
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/Air Quality
Jim Plosay, ADEC/Air Quality
Aaron Simpson, ADEC/Air Quality
David Fish/Aurora Energy, LLC
Tim Hamlin/EPA Region 10
Dan Brown/EPA Region 10
Zach Hedgpeth/EPA Region 10

ADEC Request for Additional Information
Aurora Energy LLC. – Chena Power Plant
BACT Analysis Review
Environmental Resources Management Report, March 2017

September 10, 2018

Please address the following comments by providing the additional information identified by November 1, 2018. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public review. In order to provide this additional review opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public review period or based upon the new information provided in response to this information request.

This document does not represent a final BACT determination by ADEC. Please contact Aaron Simpson at aaron.simpson@alaska.gov with any questions regarding ADEC's comments.

1. Alternative Fuel Source – Page 17 of the analysis indicates that it is assumed that use of another type of coal would not reduce NOx emissions, and use of an alternate fuel is considered technically infeasible, but did not include a substantive analysis. As indicated in the Approval and Promulgation of the State of Washington's Regional Haze State Implementation Plan[1], the use of SNCR and Flex Fuel[2] was selected as BART for the TransAlta coal-fired power plant. Evaluate alternative coal sources as a potential control option for the coal-fired boilers and identify energy, environmental, and economic impacts and other costs that would affect the selection of an alternative source of coal as a technically feasible control option. Evaluate the control efficiency of alternative coal sources based on a comparison of the coal's heat content as well as nitrogen and sulfur content.
2. Low Excess Air (LEA) and Overfire Air (OFA) – Operating at LEA involves reducing the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compliant boiler operation. NOx formation is inhibited because less oxygen is available in the combustion zone. Overfire air is the injection of air above the main combustion zone. Implementation of these techniques may also reduce operational flexibility; however, they may reduce NOx by 10 to 20 percent from uncontrolled levels.[3] Evaluate these technically feasible control technologies using EPA's top down approach.
3. Additional SO_2 Control Technologies – The BACT analysis does not include a substantive analysis of spray-dry scrubbing, dry flue gas desulfurization, dry scrubbing, or dry sorbent injection (DSI). All of these technologies have the potential to offer SO_2 removal, and therefore must be included in the analysis. Page 32 of the analysis indicates that the combined exhaust from the Chena Power Plant is currently controlled by a common baghouse and that installation of a dry injection or spray drying operation would require the existing baghouse be retrofit with a new PM control system to accommodate the much greater PM loading produced by a dry injection or spray dry system. It further states that the installation of such technologies would

[1] EPA–R10–OAR–2012–0078, FRL–9675–5

[2] Flex Fuel is the "switch from Centralia, Washington coal to coal from the Power River Basin in Wyoming. Powder River Basin coal has a higher heat content requiring less fuel for the same heat extraction, as well as a lower nitrogen and sulfur content than coal from Centralia. Flex Fuel also required changes to boiler design to accommodate Powder River Basin coal."

[3] https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

be cost-prohibitive and therefore technically infeasible. However, the BACT analysis must include rigorous site-specific evaluation of the technical feasibility and cost effectiveness of these technologies.

The EPA cost manual does not currently include a chapter covering DSI. However, as part of their Regional Haze FIP for Texas, EPA Region 6 developed cost estimates for DSI as applied to a large number of coal fired utility boilers. See the Technical Support Documents for the Cost of Controls Calculations for the Texas Regional Haze Federal Implementation Plan (Cost TSD) for additional information. The Cost TSD and associated spreadsheets are located at: https://www.regulations.gov/document?D=EPA-R06-OAR-2014-0754-0008. Please update the cost analysis for these technologies and provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Provide in the analysis: the control efficiency associated with the technologies, captured emissions (tons per year), emissions reduction (tons per year), capital costs (2017 dollars), operating costs (dollars per year), annualized costs (dollars per year), and cost effectiveness (dollars per ton) using EPA's cost manual. Please see comments 5, 6, and 7 for additional information related to retrofit costs, baseline emissions, and factor of safety.

4. BACT limits – BACT limits by definition, are numerical emission limits. However regulation allows a design, equipment, or work/operational practices if technological or economic limitations make a measurement methodology infeasible. Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for pollutant for each emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. Measures to minimize the occurrence of these periods, or to minimize emissions during these periods are control options. Combinations of steady-state control options and SSM control options can be combined to create distinct control strategies. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

5. Retrofit Costs – EPA's Control Cost Manual indicates that study-level cost estimates (± 30 percent) should not include a retrofit factor greater than 30 percent, so detailed cost estimates (± 5 percent) are required for higher factors. High retrofit cost factors (50 percent or more) may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement). Provide detailed cost analyses and justification for difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analysis.

6. Baseline Emissions – Include the baseline emissions for all emission units included in the analysis. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). NSPS and NESHAP requirements are not considered in calculating the baseline emissions. The baseline is usually the legal limit that would exist, but for the BACT determination. Baseline takes into account the effect of equipment that is part of the design of the unit (e.g., water injection and LNBs) because they are considered integral components to the unit's design. If the uncontrolled emission rate is 'soft,' run the cost effectiveness calculations using two or three different baselines.

7. Factor of Safety – If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control

efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.

8. Good Combustion Practices – For each emission unit type (coal boilers, distillate boilers, engines, and material handling) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices. Include any work or operational practices that will be implemented and describe how continuous compliance with good combustion practices will be achieved.

9. Interest Rate – All cost analyses must use the current bank prime interest rate. This can be found online at https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table). Please revise the cost analyses as appropriate.

10. Provide an economic analysis for circulating dry scrubber (CDS) SO_2 technology for the coal fired boilers (EUs 1-6). Provide in the analysis: the control efficiency associated with CDS, captured emissions (tons per year), emissions reduction (tons per year), capital costs (2017 dollars), operating costs (dollars per year), annualized costs (dollars per year), and cost effectiveness (dollars per ton) using EPA's cost manual. Please provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs).

11. Review the cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the cost effectiveness calculations and indicates that the model is intended to calculate estimated total project cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent and the gross generating capacity of the plant. Please use this spreadsheet to calculate the cost effectiveness of SO_2 removal in dollars per ton and identify all assumptions and technical justifications used in the analysis. In this analysis use a bottom-up cost estimating approach based on actual plant conditions. These conditions would include SO_2 emission rates based on current PTE, permit constraints (where applicable and enforceable), available space, ambient conditions, and local factors such as construction logistics, labor wage rates, and local sorbent costs.

12. Site-Specific Quotes Needed – The cost analyses, particularly for SO_2 control technologies, must be based on emission unit-specific quotes for capital equipment purchase and installation costs at each facility. These are retrofit projects which must be considered individually in order to obtain reliable study/budget level (+/- 30%) cost estimates which are appropriate to use as the basis for decision making in determining BACT.

Attachment: EPA comments on ADEC Preliminary Draft Serious SIP Development materials for the Fairbanks serious $PM_{2.5}$ nonattainment area

General

The attached comments are intended to provide guidance on the preliminary drafts of SIP documents in development by ADEC. We expect that there will be further opportunities to review the more complete versions of the drafts and intend to provide more detailed comments at that point

1. Statutory Requirements - This preliminary draft does not address all statutory requirements laid out in Title I, Part D of the Clean Air Act or 40 C.F.R. Part 51, Subpart Z. The submitted Serious Area SIP will need to address all statutory and regulatory requirements as identified in Title I, Part D of the Clean Air Act, 40 C.F.R. Part 51, Subpart Z, the August 24, 2016 $PM_{2.5}$ SIP Requirements Rules (81 FR 58010, also referred to at the $PM_{2.5}$ Implementation Rule), and any associated guidance.

   In the preliminary drafts, notable missing elements included: Reasonable Further Progress, Quantitative Milestones, and Conformity. This is not an exhaustive list of required elements.

   The NNSR program is a required element for the serious area SIP. We understand ADEC recently adopted rule changes to address the nonattainment new source review element of the Serious SIP, and that ADEC plans to submit them to the EPA separately in October 2018. Thank you for your work on this important plan element.

2. Extension Request - This preliminary draft does not address the decision to request an attainment date extension and the associated impracticability demonstration. On September 15, 2017, ADEC sent a letter notifying the EPA that it intends to apply for an extension of the attainment date for the Fairbanks $PM_{2.5}$ Serious nonattainment area. The Serious Area SIP submitted to EPA will need to include both an extension request and an impracticability demonstration that meet the requirements of Clean Air Act section 188(e). In order to process an extension request, the EPA requests timely submittal of your Serious Area SIP to allow for sufficient time to review and take action prior to the current December 2019 attainment date, so as to allow, if approvable, the extension of the attainment date as requested/appropriate. For additional guidance, please refer to 81 FR 58096.

3. Split Request - We support the ADEC and the FNSB's decision to suspend their request to the EPA to split the nonattainment area. We support the effort to site a monitor in the Fairbanks area that is more representative of neighborhood conditions and thus more protective of community health. This would provide additional information on progress towards achieving clean air throughout the nonattainment area.

4. BACM (and BACT), and MSM - Best Available Control Measures (including Best Available Control Technologies) and Most Stringent Measures are evaluative processes inclusive of steps to identify, adopt, and implement control measures. Their definitions are found in 51.1000, 51.1010(a).

All source categories, point sources – area sources – on-road sources – non-road sources, need to be evaluated for BACM/BACT and MSM. De minimis or minimal contribution are not an allowable rationale for not evaluating or selecting a control measure or technology.

The process for identifying and adopting MSM is separate from, yet builds upon, the process of selecting BACM. Given that Alaska is intent on applying for an extension to the attainment date, Alaska must identify BACM and MSM for all source categories. These processes are described in 51.1010(a) and 51.1010(b) and in the $PM_{2.5}$ Implementation Rule preamble at 81 FR 58080 and 58096. We further discuss this process in the "BACM (and BACT), MSM" section that starts on page 3 below.

5. Resources and Implementation - The serious area $PM_{2.5}$ attainment plan will be best able to achieves its objectives when all components of the SIP, both the ADEC statewide and FNSB local measures, are sufficiently funded and fully implemented.

6. Use of Consultants- For the purpose of clarity, it will be important to identify that while contractors are providing support to ADEC, all analyses are the responsibility of the State.

Emissions Inventory

1. Extension Request Emission Inventories - Emissions inventories associated with the attainment date extension request will need to be developed and submitted. Table 1 of the Emissions Inventory document is one example where the submittal will need to include the additional emissions inventories, including RFP inventories, extension year inventories for planning and modeling, and attainment year planning and modeling inventories, associated with the attainment date extension request.

2. Modeling Requirements - Related to emissions inventory requirements, the serious area SIP will need to model and inventory 2023 and 2024, at minimum. We recommend starting at 2024 and modeling earlier and earlier until there is a year where attainment is not possible. That would satisfy the requirement that attainment be reached as soon as practicable.

3. Condensable Emissions - All emissions inventories and any associated planning, such as Reasonable Further Progress schedules, need to include condensable emissions as a separate column or line item, where available. Where condensable emissions are not available separately, provide condensable emissions as included (and noted as such) in the total number. The following are examples of where this would need to be incorporated in to the Emissions Inventory document:
    a. Page 20, paragraph 5 (or 2nd from the bottom).
    b. Page 34, Table 8. Include templates.

Precursor Demonstration

1. Ammonia Precursor Demonstration - The draft Concepts and Approaches document, Table 4 on page 9, states that a precursor demonstration was completed for ammonia and that the result was "Not significant for either point sources or comprehensively." The Precursor Demonstration chapter does not include an analysis for ammonia. Please include the precursor demonstration for ammonia in the Serious Plan or amend this table.

2. Sulfur Dioxide Precursor Description - The draft Concepts and Approaches document, Table 4 on page 9, states that sulfur dioxide was found to be significant. All precursors are presumptively considered significant by default and the precursor demonstration can only show that controls on a precursor are not required for attainment. Suggested language is, "No precursor demonstration possible."

BACM (and BACT), MSM

Overall

The EPA appreciates ADECs efforts to identify and evaluate BACM for eventual incorporation into the Serious Area SIP. The documents clearly display significant effort on the part of the state and are a good first step in the SIP development process. In particular, we are supportive of ADECs efforts to evaluate BACT for the major stationary sources in the nonattainment area, as control of these sources is required by the CAA and $PM_{2.5}$ SIP Requirements Rule.

1. BACM/BACT and MSM: Separate Analyses - The "Possible Concepts and Potential Approaches" document appears to conflate the terms BACM/BACT and MSM, as well as, the analyses for determining BACM/BACT and MSM. BACM and MSM have separate definitions in 40 CFR 51.1000. By extension, the processes for selecting BACM and MSM are laid out separately in the $PM_{2.5}$ SIP Requirements Rule (compare 40 CFR 51.1010(a) for BACM and 40 CFR 51.1010(b) for MSM). Accordingly, the serious area SIP submission will need to have both a BACM/BACT analysis and an MSM analysis. We believe that there is flexibility in how these analyses can be presented, so long as the submission clearly satisfies the requirements of both evaluations, methodologies, and findings.

2. Selection of Measures and Technologies - The CAA and the $PM_{2.5}$ SIP Requirements Rule requires that ***all*** available control measures and technologies that meet the BACM (including BACT) and MSM criteria need to be implemented. All source categories need to be evaluated including: point sources (including non-major sources), area sources, on-road sources, and non-road sources.

3. Technological Feasibility - All available control measures and technologies include those that have been implemented in nonattainment areas or attainment areas, or those potential measures and technologies that are available or new but not yet implemented. Similarly, Alaska may not automatically eliminate a particular control measure because other sources or nonattainment areas have not implemented the measure. The regulations do not have a quantitative limit on number of controls that should be implemented.

For technological feasibility, a state may consider factors including local circumstances, the condition and extent of needed infrastructure, or population size or workforce type and habits, which may prohibit certain potential control measures from being implementable. However, in the instance where a given control measure has been applied in another NAAQS nonattainment area, the state will need to provide a detailed justification for rejecting any potential BACM or MSM measure as technologically infeasible (81 FR 58085).

A Borough referendum prohibiting regulation of home heating would not be an acceptable consideration to render potential measures technologically infeasible. The State would be responsible for implementing the regulations in the case that the Borough was not able. We believe that the most efficient path to clean air in the Borough is through a local, community effort.

4. Economic Feasibility - The BACM (including BACT) and MSM analyses need to identify the basis for determining economic feasibility for both the BACM and MSM analyses. In general, the $PM_{2.5}$ SIP Requirements Rule requires the state apply more stringent criteria for determining the feasibility of potential MSM than that used to determine the feasibility of BACM and BACT, including consideration of higher cost/ton values as cost effective.

5. Timing - The evaluations will need to identify the time for selection, adoption, and implementation for all measures. BACT must be selected, adopted, and implemented no later than 4 years after reclassification (June 2021). MSM must be selected, adopted, and implemented no later than 1 year prior to the potentially extended attainment date (December 2023 at latest). The RFP section of the serious area plan will need to identify the BACM and MSM control measures, their time of implementation, and the time(s) of expected emissions reductions. Timing delays in selection, adoption, implementation are not considered for BACM and MSM.

   As mentioned in the comment above in the "General" comment section, there are three criteria distinguishing between BACM and MSM, not one.

BACM - General

1. BACM definition, evaluations - The definition of BACM at 40 CFR 51.1000 describes BACM as any measure "that generally can achieve greater permanent and enforceable emissions reductions in direct $PM_{2.5}$ and/or $PM_{2.5}$ plan precursors from sources in the area than can be achieved through the implementation of RACM on the same sources." We believe that potential measures that are no more stringent than existing measures already implemented in FNSB, those that do not provide additional direct $PM_{2.5}$ and/or $PM_{2.5}$ precursors emissions reductions, do not meet the definition of BACM. These would need to be evaluated in the BACM and MSM analysis.

   For measures that are currently being implemented in Fairbanks that provide equivalent or more stringent control, we recommend identifying the ADEC or Borough implemented measure as part of the BACM control strategy. These implemented measures should be listed in their BACM findings at the end of the document. This comment applies to all of the

measures that were screened out from consideration due to not being more stringent than the already implemented measure.

The analyses for a number of measures (e.g., Measure 30, Distribution of Curtailment Program information at time of woodstove sale) conclude that the emission reductions would be insignificant and difficult to quantify and, therefore, the measure is not technologically feasible. These measures may be technologically feasible. However, if existing measures constitute a higher level of control or if implementation of the measures is economically infeasible those would be valid conclusions if properly documented. De minimis or minimal contribution is not a valid rationale for not considering or selecting a control measure or technology.

The conclusion "not eligible for consideration as BACM" is not valid as all assessments for BACM and MSM are part of the evaluation. More appropriate conclusions could include that existing measures qualify as BACM or MSM, or are more stringent. Additional conclusions could include that evaluated measures were not technologically feasible, economically feasible, or could not practically be adopted and implemented prior to the required timeframe for BACM or MSM.

2. BACM and MSM, Ammonia - In the Approaches and Concepts document, Table 5 references that there are no applicable control measures or technologies for the $PM_{2.5}$ precursor ammonia. No information to substantiate this claim are found in the preliminary draft documents. Unless NH_3 is demonstrated to be insignificant for this area, the serious area plan will need to include an evaluation of NH_3 and potential controls for all source categories including points sources.

3. Backsliding Potential - When benchmarking the BACM and MSM analyses for stringency, ensure that the evaluation is based on the measures approved into the current Moderate SIP. This will relate primarily to the current ADEC/FNSB curtailment program but also other related rules. Many wood smoke control measures are interrelated, and changes to those measures may affect determinations on stringency of directly related and indirectly related measures. Examples of this can be found in multiple measures including, but not limited to Measures 5, 7, and 16.

4. Transportation Control Measures - The Approaches and Concepts document, on Page 13, states that the MOVES2014 model does not estimate a PM benefit as a result of an I/M program, and therefore the I/M is not technologically feasible. This is not a valid conclusion given that the Fairbanks area operated an I/M program to reduce carbon monoxide and the Utah Cache Valley nonattainment areas has an I/M program for VOC control. This measure will need to be evaluated. Referring to the 110(l) analysis for the Fairbanks CO I/M program may provide insight into how to quantify the emissions associated with an I/M program.

With regard to control measures related to on-road sources, we have received inquiries from the community regarding idling vehicles and further evaluation emission benefits would be responsive to citizen concern and may provide additional air quality benefit.

BACM - Specific Measures

- Measure 16, page 34-35. Date certain Removal of Uncertified Devices. The "date certain" removal of uncertified woodstoves in Tacoma, Washington appears more stringent than the current Moderate SIP approved Fairbanks ordinance in terms of the regulation and in practice. While the current ordinance appears to provide similar protection during stage 1 alerts, this is dependent on 100% compliance and the curtailment program remaining in its current form. Removal of uncertified stoves guarantees reductions in emissions in the airshed during both the curtailment periods and throughout the heating season. The information provided does not support the conclusion that the Fairbanks controls provides equivalent or more stringent control. Date certain removal of uncertified wood stoves needs to be considered for the area.

  Measures R4, R9, and R12, page 64, 68 and 71. These measures do not reference the Puget Sound Clean Air Agency (Section 13.07) requirement for removal of all uncertified stoves by September 30, 2015. This is equivalent to having all solid fuel burning appliances be certified and would be more stringent than the current SIP approved rules in Fairbanks. We believe that these measures need to be evaluated in the BACM and MSM analyses.

  Measure R4 and R9, page 64 and 68. All Wood Stoves Must be Certified. These measure should be evaluated.

- Measure 19-20 and 25, page 36-38 and 39. Renewal and Inspection Requirements. ADEC has not adequately demonstrated their conclusion that Fairbanks has a more stringent measure than Missoula and San Joaquin. We believe that the renewal requirements and inspection/maintenance requirements associated with the Missoula alert permits and San Joaquin registrations allows the local air agency an opportunity to verify on a regular basis that the device operates properly over times. Wood burning appliances require regular maintenance in order to achieve the certified emissions ratings. The FNSB Stage 1 waivers do not have an expiration and do not have an inspection and maintenance component making it less stringent.

- Measure 31, page 43. While the Borough has SIP approved dry wood requirements that prohibit the burning of wet wood and moisture disclosure requirements by sellers, we believe that a measure limiting the sale of wet wood during the winter months should be further analyzed for BACM (and MSM) consideration.

- Measures 33, 35, 36, 37, 43. Multiple Measures identify that recreational fires have been exempted from existing regulations. Small unregulated recreational fires, bonfires, fire pits,

and warming fires have the potential to contribute emissions during a curtailment period. The FNSB and ADEC regulations should be re-evaluated for removing this exclusion.

- Measure 49, page 58. Ban on Coal Burning. We believe the regulations in Telluride are more stringent than in Fairbanks. Telluride prohibits coal burning all year whereas in Fairbanks an existing coal stove can burn when there is no curtailment which could contribute additional emissions to the airshed, especially during poor conditions when a curtailment may not have been called. We do not agree with the conclusion that the PM_{10} controls are ineligible for consideration for control of $PM_{2.5}$.

- Measure R20, page 76. Transportation Control Measures related to Vehicle Idling. We have received multiple inquiries regarding community interest in controlling emissions from idling vehicles. These types of control measures should be further evaluated in the BACM and MSM analyses.

- Measure 1, page 79-81. Surcharge on Solid Fuel Burning Appliances. For purposes of implementing an effective program to reduce $PM_{2.5}$ in the Borough we believe that a surcharge may be a helpful way to supplement limited funds. Implementation efforts within the nonattainment area could benefit from $24,000 of additional funding whether used for a code enforcer or other support of the wood smoke programs.

- Additional controls that should be further evaluated for BACM and MSM include:
    - Measure R1, page 63: Natural gas fired kiln or regional kiln.
    - Measure R12, page 71: Replace uncertified stoves in rental units.
    - Measure R17, page 75: Ban use of wood stoves
    - Measure R6, page 65: Remove Hydronic Heaters at Time of Home Sale & Date certain removal of Hydronic heaters. We suggest evaluating these measures at the state and local level.
    - Weatherization / heat retention programs should be evaluated. These should be evaluated for existing homes through energy audits and increasing insulation and energy efficiency. For new construction, building codes (Fairbanks Energy Code) should be evaluated with reference to the IECC Compliance Guide for Homes in Alaska http://insulationinstitute.org/wp-content/uploads/2015/12/AK_2009.pdf, and the DOE R-value recommendations, http://www.fairbanksalaska.us/wp-content/uploads/2011/07/ENERGY-CODE.pdf. (Note: More recent information may be available.)
    - Fuel oil boiler upgrades / operation & maintenance programs should be evaluated.

BACM - Ultra-Low Sulfur Fuel

1. Incomplete Analysis - The report findings provide analysis of the demand curve over a relatively short (12 month) time frame. This analysis appears to be based on a partial equilibrium model. This is a misleading time frame given the volatility of demand side fuel oil pricing. Also, in order to determine the equilibrium price, the analysis must also analyze

the supply curve. The report does not include information about the future supply side costs but needs to in order to make conclusions about the cost to the community of ultra-low sulfur heating oil.

2. Analysis of Increased Supply, Consumption - The report does not address future change in the market nor potential economies of scale to be achieved by an increase in ultra-low sulfur fuel consumption. Page 3 of the report identifies that, "the additional premium to purchase ULS over HS, decreased significantly since 2008-2010. It is likely that, this can be attributed to increased ULS capacity." We believe that the report should further explore the supply side costs.

3. Supply Cost Analysis - A supply side cost analysis is necessary to better understand the cost to the supplier to produce and provide ULS heating fuel. The BACM analysis must start with a transparent and detailed economic analysis of exclusively supplying ultra-low sulfur heating oil to the nonattainment area.

4. BACM Assessment - The current analysis does not provide information needed to assess BACM economic feasibility. The report should analyze the total cost to industry of delivering ultra-low sulfur heating oil to the entire community in terms of standard BACM metrics, $/ton.

BACT

General Comments

At this time, EPA is providing general comments based on review of the draft BACT analyses prepared by ADEC as well as addressing certain issues discussed in earlier BACT comments provided by EPA. Detailed comments regarding each individual analysis are not being provided at this time. While EPA appreciates the time and effort invested by ADEC staff in preparing the draft BACT analyses, the basic cost and technical feasibility information needed to form the basis for retrofit BACT analyses at the specific facilities has not been prepared. In other words, analyses which are adequate to guide decision making regarding control technology decisions for these rather complex retrofit projects cannot be prepared without site specific evaluation of capital control equipment purchase and installation costs, and site specific evaluation of retrofit considerations. EPA will conduct a thorough review of any future BACT or MSM analyses which are prepared based on adequate site specific information, and will provide detailed comments relative to each emission unit and pollutant at that time.

1. Level of Analysis – The analyses are presented as "preliminary BACT/MSM analyses" on the website, but the documents themselves are titled only as BACT analyses and the conclusions only reflect BACT. Additionally, the determinations may not be stringent enough to be considered BACT given that better performing SO_2 control technologies have not been adequately analyzed. These analyses cannot be considered to provide sufficient basis to support a selection of MSM.
2. Site-Specific Quotes Needed – The cost analyses, particularly for SO_2 control technologies, must be based on emission unit-specific quotes for capital equipment purchase and

installation costs at each facility. These are retrofit projects which must be considered individually in order to obtain reliable study/budget level (+/- 30%) cost estimates which are appropriate to use as the basis for decision making in determining BACT and potentially MSM. EPA believes that control decisions of this magnitude justify the relatively small expense of obtaining site-specific quotes.

3. SO_2 Control Technologies – The analyses must include evaluation of circulating dry scrubber (CDS) SO_2 control technology. This demonstrated technology can achieve SO_2 removal rates comparable to wet flue gas desulfurization (FGD) at lower capital and annual costs, and is more amenable to smaller units and retrofits. Modular units are available.
4. Control Equipment Lifetime – The analyses must use reasonable values for control equipment lifetime, according to the EPA control cost manual (EPA CCM). EPA believes that the following equipment lifetimes reflect reasonable assumptions for purposes of the cost analysis for each technology as stated in the EPA control cost manual and other EPA technical support documents. Use of shorter lifetimes for purposes of the cost analysis must include evidence to support the proposed shortened lifetime. One example where EPA agrees a shortened lifetime is appropriate would be where the subject emission unit has a federally enforceable shutdown date. Certain analyses submitted in the past have claimed shortened equipment lifetimes based on the harshness of the climate in Fairbanks. In order to use an equipment life that is shortened based on the harsh climate, evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers. Lacking adequate justification, all cost analyses must use the following values for control equipment lifetime:
    a. SCR, Wet FGD, DSI, CDS, SDA – 30 years
    b. SNCR – 20 years
5. Availability of Control Technologies – Technologically feasible control technologies may only be eliminated based on lack of availability if the analysis includes documented information from multiple control equipment vendors (who provide the technology in question) which confirms the technology cannot be available within the appropriate implementation timeline for the emission unit in question.
6. Assumptions and Supporting Documents – All documents cited in the analyses which form the basis for costs used and assumptions made in the analyses must be provided. Assumptions made in the analyses must be reasonable and appropriate for the control technologies included in the cost analysis.
7. Interest Rate – All cost analyses must use the current bank prime interest rate according to the revised EPA CCM. As of May 10, 2018, this rate is 4.75%. See https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table).
8. Space Constraints – In order to establish a control technology as not technologically feasible due to space constraints or other retrofit considerations, detailed site specific information must be submitted in order to establish the basis for such a determination, including detailed drawings, site plans and other information to substantiate the claim.
9. Retrofit Factors – All factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor or whether installation of a specific control technology is technologically infeasible. EPA Region 10

believes that installation factors which would complicate the retrofit installation of the control technology should be evaluated by a qualified control equipment vendor and be reflected in a site-specific capital equipment purchase and installation quote. Lacking site-specific cost information, all factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor. One example of the many retrofit considerations that must be evaluated is the footprint required for each control technology. A vendor providing a wet scrubber will be able to estimate the physical space required for the technology, and evaluate the existing process equipment configuration and available space at each subject facility. The determination of whether a specific control technology is feasible and what the costs will be may be different at each facility based on this and other factors. Site-specific evaluation of these factors must be conducted in order to provide a reasonable basis for decision making.

10. Control Efficiency – Cost effectiveness calculations for each control technology must be based on a reasonable and demonstrated high end control efficiency achievable by the technology in question at other emission units, or as stated in writing by a control equipment vendor. If a lower pollutant removal efficiency is used as the basis for the analysis, detailed technical justification must be provided. For example, the ability of SCR to achieve over 90% NO_X reduction is well established, yet the ADEC draft analyses assume only 80% control. Use of this lower control efficiency requires robust technical justification.
11. Condensable Particulate Matter – Although the existing control technology on the coal fired boilers may be evaluated as to whether it meets the requirement for BACT for particulate matter, baghouses primarily reduce emissions of filterable particulate matter rather than condensable PM. Given that all condensable PM emitted by the coal fired boilers would be classified as $PM_{2.5}$, the BACT analyses must include consideration of control options for these emissions. Where control technologies evaluated for control of other pollutants may provide a collateral benefit in reducing emissions of $PM_{2.5}$, this should be evaluated as well.
12. Guidance Reference – The steps followed to perform the BACT analysis mentioned in section 2 are from draft NSR/PSD guidance. The correct reference should be 81 FR 58080, 8/24/2016. As a result of this, some of the steps outlined in the BACT analysis need to be updated.
13. Community Burden Estimate – The concepts and approaches document labels capital purchase and installation costs for air pollution control technology at the major source facilities as "community burden" (see Tables 7 and 8, pages 10-11). EPA believes it is important to properly label the cost numbers being used as capital purchase and installation costs, since presenting them as community burden appears to attribute the entire initial capital investment for the various control technologies to the community in a single year, and also ignores annual operation and maintenance costs. As described in the EPA CCM, the cost methodology used by EPA for determining the cost effectiveness of air pollution control technology amortizes the initial capital investment over the expected life of the control device, and includes expected annual operating and maintenance expenses. EPA believes presentation of this annualized cost over the life of the control technology more accurately represents the actual cost incurred and is consistent with how cost effectiveness is estimated in the context of a BACT analysis.
14. Conversion to Natural Gas – For any emission units capable of converting to natural gas combustion (with the requisite changes to the burners, etc), the MSM analysis in particular

should thoroughly evaluate the feasibility of this option. For example, GVEA has stated the combustion turbines at its North Pole Expansion Power Plant have the ability to burn natural gas, and the IGU has indicated the intent to expand the supply of natural gas to Fairbanks and North Pole.

APPENDIX:

Additional Comments and Suggestions

Possible Concepts and Potential Approaches

Throughout all SIP documents references to design values should include a footnote to the source of the information (e.g., "downloaded from AQS on XX/XX/XXX" or "downloaded from [state system] on XX/XX/XXXX") and how exceptional events were treated.

We suggest referencing the August 24, 2016 81 FR 58010 Fine Particulate Matter NAAQS: State Implementation Plan Requirements rule with one consistent term. We suggest the 2016 $PM_{2.5}$ Implementation Rule.

Page 4, Figure 1. The comparative degree days and heating related information is better suited for the sections evaluating BACM and economic feasibility. If intending on using this information to differentiate Fairbanks from other cold climates and/or nonattainment areas, depicting comparative home heating costs would be more supportive.

Page 4, Table 1. The design values in the table and in the discussion need to be updated for 2015-2017.

Page 6-7: The "Totals" row in Table 3 (non-attainment areas emissions by source sector) does not appear to be the sum of the individual source sector emissions.

Page 7: The statement about FNSB experiencing high heating energy demand per square foot needs to be referenced.

Page 7: The discussion of Eielson AFB growth needs a reference to the final EIS.

Page 9: Table 4's title should be changed to "Preliminary Precursor Demonstration Summary"

Page 9: Table 4 includes a column "Modeling Assessment". Not all precursors were assessed with modeling, and modeling is just one tool for the precursor demonstration. A suggestion for the column title is "Result of Precursor Demonstration."

Page 9: Table 5's title should be changed to "Preliminary BACT Summary." Table 5 also needs to update the title to reference "Precursor Demonstration" as the term "Precursor Significance Evaluation" is the incorrect terminology for this analysis.

Page 10: ADEC's proposal to only require one control measure per major stationary source to meet BACT and MSM for SO_2, is not consistent with the Act or rule. As discussed above, BACM and MSM have separate definitions in 40 CFR 51.1000. By extension, the processes for

selecting BACM and MSM are laid out separately in the PM2.5 SIP Requirements Rule (compare 40 CFR 51.1010(a) for BACM and 40 CFR 51.1010(b) for MSM).

Page 10: Table 6 should identify the specific dry sorbent injection selected as BACT.

Page 11: Suggest changing “less sources” to “fewer sources.”

Page 13: The statement about an I/M program providing PM benefit needs to be clarified. Is this referring just to NOx and VOC precursor contribution to PM2.5, or also direct PM2.5 benefits?

Page 14: The statement “ADEC interprets the main difference between BACT/BACM and MSM as the time it takes to implement a control” is inaccurate. As discussed above, although the rule sets our different schedules for implementation of MSM and BACM, this is not the only major difference between those concepts. Notably, the rule contemplates a higher stringency for MSM as well as a higher cost/ton threshold for determining economic feasibility of the measure.

Technical Analysis Protocol

Page 2: The design values at the top of the page need to be updated to 2015-2017.

Page 2: Recommend removing the sentence “This site will be included in the Serious SIP’s attainment plan…” as the North Pole Elementary will be involved in the redesignation to attainment in the sense that all past and current monitoring data will be a part of an unmonitored area analysis to show that the entire area has attained the standard in addition to the regulatory monitor locations.

Page 2: Remove the discussion of the nonattainment area split.

Page 2: Paragraph 2, sentence 3 should refer to the unmonitored area analysis.

Page 2: The timeline described at the bottom of the page needs to be modified to reflect a current schedule. No projected year modeling was included in the preliminary draft documents. Control scenario modeling will likely not be completed in Q2 2018.

Page 3: We suggest a sentence overview of the unmonitored area analysis in Section 3.1.

Page 3: Section 3.2 needs to refer to the SPM data and how that will be used in the Serious Plan unmonitored area analysis. This section should discuss current DEC efforts to site a new monitor in Fairbanks.

Page 3: Section 3.4 needs to describe the CMAQ domain in addition to the WRF domain. A figure (map) would help.

Page 4: Section 3.5 needs a more developed discussion of the WRF assessment, including describing the criteria that were used to assess the state-of-the-art, what the current version is, and what version was used.

Page 4: Section 3.6 needs to reference all emission inventories in development, including potential attainment date extension years and RFP years.

Page 4: In Section 4.1, the statement about the Moderate SIP covering the relevant monitors for the Serious SIP is inaccurate. The statement needs to qualify whether it is referring to regulatory monitors or non-regulatory monitors. In addition, the North Pole Fire Station, NCore, and North Pole Elementary monitors were not included in the Moderate SIP.

Page 5: Table 4.1-1's title suggests that all SPM sites are listed, but only sites with regulatory monitors are listed. Please list all the SPM sites used in the unmonitored area analysis in a separate table and modify this title of Table 4.1-1 to reflect that it lists sites that are regulatory.

Page 5: North Pole Elementary was a regulatory site for a part of the baseline period and was NAAQS comparable. Table 4.1-1 needs to be updated.

Page 8: Table 4.2-1 should be updated to include 2011-2017 98^{th} percentiles. Table 4.2-2 should be updated to include 3-year design values for 2013-2017. For clarity, we recommend the 3-year design values include the full period in order to better distinguish from Table 4.2-1. For instance, "2013" would be "2011-2013".

Page 8: The statement starting, "a clear indication…" needs to be amended or removed. It is inaccurate. The prevalence of organic carbon does not indicate the dominance of wood burning, much less a clear indication. Many sources in Fairbanks emit organic carbon.

Page 8: The statement starting "The concentration share…" need to be amended or removed. Suggest removing "drastically". There is no scientific definition of a drastic change in percentages of $PM_{2.5}$ species, nor does the different 56% to 80% appear "drastic."

Page 9: The detailed description of the Simpson and Nattinger analysis does not reflect that SANDWICH process and it is preliminary data. It should be included within the body of the Serious Plan appendix on monitoring, but is out of place in a summary TAP.

Page 9: there are two different tables with the same table number (Table 4.3-1).

Page 10: Please clarify Table 4.4-1. This appears to be the design value calculation for the 5-year baseline design value, 2011-2015. If correct, then please label the 3-year design values according to the three years (e.g., "2011-2013"), clarify the table heading as being the "Five Year Baseline Design Value, 2011-2015 (µg/m3)", and clarify that the last column is the 5 Year Baseline Design Value associated with the table heading.

Page 11: At the end of section 5, please refer to the emission inventory chapter's meteorological discussion of the episodes.

Page 11: Section 6 needs to justify the extent, resolution, and vertical layer structure of the CMAQ domain (and the WRF domain) or refer to where that is included in the Moderate Plan.

Page 13: We suggest changing "PMNAA" to "NAA" to be consistent with the EI chapter.

Page 15, Section 8.1: There needs to be mention of how the F-35 deployment will be considered, with a reference to the final EIS.

Page 15-19: section 8.2-8.6 use the future tense for tasks that have been completed and are inconsistent with the schedule at the beginning of the TAP. Please adjust based on current status.

Page 20, section 9.2 states that "a BACT analysis is an evaluation of all technically available control technologies for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts." This sentence should be revised to reflect that the technological feasibility assessment occurs after identification of all potential control measures for each source and source category.

Page 20, section 9.3 the second sentence should read: "BACM measures found to be economically infeasible for BACM *must* be analyzed for MSM."

Page 21: Section 10.1 needs to be updated to reflect the current CMAQ version (5.2.1) and a discussion of why that model has not been used.

Page 21: Suggest sentence starting "There will be a gap…" be changed to "There is a gap in terms of assessing the performance at the North Pole Fire Station monitor for the Serious Plan because the State Office Building in Fairbanks was the only regulatory monitor at the time of the 2008 base case modeling episodes."

Page 23: Please explain the solid and dashed lines in the soccer plot.

Page 23: Please be sure to include a full discussion of North Pole performance in this section. Even though we lack measurements, we can discuss the ratio of the modeling results at NPFS versus SOB versus that ratio from more recent monitoring data (2011-2015 baseline design value period).

Page 23: Please clarify what is meant by "Moderate Area SIP requirements."

Page 24: The discussion of the 2013 base year discusses representative meteorological conditions without describing what the representative meteorological conditions are for high $PM_{2.5}$. Please reference the discussion of representative meteorological conditions that will be found elsewhere in the SIP.

Page 24: The discussion of the modeling years needs to be consistent and reflect the extension request past 2019. The attainment year cannot be earlier than 2019. Each extension year must be individually requested. For modeling efficiency, we recommend starting with 2024. If that year attains, then 2023 and so on until we have one year that attains and the year before that does not. This should give us the information about what is the earliest year for attainment.

Page 25: We suggest changing "modeling design value" to "design value for modeling"

Page 26: Please clarify the "SMAT" label in the tables. They may be the SANDWICH concentrations and the "5-yr DV" rows are the SMAT concentrations. Please clarify the units in the rows.

Emission Inventory

Clarification – In the EI document we would like to understand the functional difference between the base year, and baseline year

Please identify the methodology for generating ammonia and condensable PM emissions numbers.

Page 1: Please be consistent in “emission inventory” versus “emissions inventory”.

Page 1: “CAA” to “Clean Air Act” for clarity

Page 3: It would be helpful to refer to 172(c)(3) in Section 1.2, bullet 1 as the planning and reporting requirements.

Page 5: Please include extension years and RFP years in Table 1’s calendar years similar to what was done for Table 2. There should be one RFP projected inventory and QM beyond the extended attainment date. It would be helpful to include basic information about extension years and RFP years to better foreshadow Table 2.

Page 7: Please clarify the “winter season” inventory as the “seasonal” inventory that represents the daily average emissions across the baseline episodes.

Page 7, paragraph 1. Please include reference documentation for the following statement, “results in extremely high heating energy demand per square foot experienced in no other location in the lower-48.”

Page 9: Please change “Violations” to “Exceedances.” Exceedance is the term for concentrations over the standard. Violations is the term for dv over the standard.

Page 9: Add “No exceedances were recorded outside the months tabulated in Table 3 that were not otherwise flagged by Alaska DEC as Exceptional Events.”, to the end of the last paragraph on the page.

Page 13: Please clarify the provenance of the BAM data (e.g., “downloaded from [state database or AQS] on XX/XX/XXXX). In particular, it is important to note if the data has been calibrated to the regulatory measurement (aka, corrected BAM).

Page 17-18. Sentence Unclear “For example, a planning inventory based on average daily emissions across the entire six-month nonattainment season will likely reflect a relatively lower fraction of wood use-based space heating emissions than one based on the modeling episode day average since wood use for space heating Fairbanks tends to occur as a secondary heating source on top of a “base” demand typically met by cleaner home heating oil when ambient temperatures get colder.”

Page 19: Remove “Where appropriate,”. All source sectors should be re-inventoried for 2013, even if the emissions for the sector ends up being the same as in 2008.

Page 19: Change “projected forward” to “re-inventoried”, or similar wording. Reserve “project” for when the emission inventory is estimating emissions in a future year.

Page 20: Please refer to EPA’s memo on the use of MOVES2014a for the plug in adjustment. As a reminder, this information is sufficient only for development of the emissions inventory, not for SIP credit.

Page 20: Please submit the technical appendix referenced on page 20. When that is submitted, we expect to provide additional comment. To allow for review, we request expedited submission.

Page 21: At bottom of page, “project” should be “re-inventoried” or something that refers to an inventory produced after the fact.

Page 22, paragraph 1, Space heating area sources. Please further explain how the combined survey data best represents 2013 emissions.

Page 23: Add information about how NH_3 was inventoried for this category.

Page 23, 2nd paragraph from bottom. Facilities need to provide direct PM and all precursors, whether directly submitted or calculated from emissions factors.

Page 23, last paragraph.

- Potential typo – we believe that 2018 should be 2013.
- Question – Does scaling emissions cause any point source to exceed its PTE?

Page 25, bullet 3, Laboratory – Measured Emissions Factors for Fairbanks Heating Devices. The statement “first and most comprehensive systematic” would be more credible if simplified.

Page 27: Clarify how data from the 2014 NEI was modified to reflect emissions in 2013. Were they assumed to be the same between the two years? Or adjusted based on population change, or some other information?

Page 33: Please include information on how the Speciate database was used to develop the modeling inventory (and perhaps elsewhere for the planning inventory, if appropriate).

Precursor Demonstration

Throughout the Serious Area SIP we recommend using the terminology, Precursor Demonstration, to be consistent with the $PM_{2.5}$ Implementation Rule.

General: The overview of the nitrate chemistry is complicated. We suggest you combine the two discussions into one and organize it with the following logic:

1. Describe the two chemical environments: (1) daytime and (2) nighttime.
2. Describe the information that supports that daytime chemistry is not relevant here.
3. Describe the information that supports that nighttime chemistry is limited by excess NO.

4. Describe what happens if the entire emission inventory was increasing by a factor of 3.6 to get appropriate concentrations in the North Pole area. How does ammonium nitrate change?
5. Describe how increasing the emission inventory and then reducing all source sectors by 75% results in less of a reduction in $P_{M2.5}$ than reducing all source sectors by 75% in the original emission inventory.
6. NOTE: We are willing to provide a rough draft of this organization, if provided the original word document.

Title page: remove "com"

Page 2: Recommend using Section 188-190 instead of 7513-7513b.

Page 2: Recommend moving the last three sentences of the first paragraph to the end of the second paragraph.

Page 2: Please add "threshold" after 1.3 in the third paragraph.

Page 2: Please explain concentration-based and sensitivity-based before using the terms.

Page 2: Please add a footnote whether the numbers in the Executive Summary are SANDWICHed or not.

Page 3: Please change "has decided" to "decided."

Page 3: Make sure the concentrations listed for ammonia include ammonium sulfate and ammonium nitrate.

Page 5-7: The figure captions say that concentrations are presented but the images themselves have percentages. Please use concentrations for this analysis.

Page 9: The first paragraph says that the point sources are not responsible for the majority of sulfate at the monitors. Please substantiate that claim, or modify it.

Page 13: Please explain the relevance of referring to the VOC emissions of home heating in this summary of VOCs.

Page 14: Recommend adding "… and adjusted to reflect speciated concentrations for a total PM2.5 equal to the five year 2011-2015 design value" to the sentence that starts "The speciated PM2.5 data [were] analyzed.

Page 14: Please include the results of the concentration based analysis, perhaps as a table.

Page 14: Clarify that the concentration used for NH_3 is the ammonium sulfate and ammonium nitrate. See the draft EPA Precursor Demonstration Guidance.

Page 17: Recommend removing "slightly" and removing the sentence referring to rounding to the nearest tenth of a microgram.

Page 17-18: To help understand what is going on with the bounding run versus the normal run, it would be helpful to have the RRFs for the Modeled 75% scenario.

BACM

Page 9 and throughout: For clarity, please refer to the implementation rule as "$PM_{2.5}$" not "PM".

Page 14, Table 3. It would be helpful to include filter speciation data.

Page 16, Table 4: Please identify the RACM measures that were technologically and economically feasible but could not be implemented in the RACM timeline or note there were none.

Page 20 and 25, Table 6 and 7: For the final Table identifying the control measures evaluated, it would be helpful to identify the following: measure, cost/ton, BACM determination, MSM determination, and any additional comments.

Page 24: 12 measures were eliminated because they were determined to offer marginal or unquantifiable benefit. However, a measure may offer marginal benefit but may also cost very little. If there is another explanation for why these measures were not considered that follows the BACM steps, please include that in the Serious Area Plan.

Page 28: Stage 1 alerts are referred to multiple times including in Measure 2 on page 28 and Measure 33, pg 47 and pg 48. Please clarify in these analyses whether the measure applies during all stages of alerts and the associated level of control with each stage.

Page 33: Measure 13 identified that no SIPs existed or EPA guidance/requirements for the measure and incorrectly used that rationale as the conclusion for not considering the measure.

Page 34: The discussion of Measure 15 does not clearly state how Alaska and the Borough ensure that devices are taken out at the point of sale. It also does not clearly state the process for ensuring a NOASH application doesn't involve a stove that should have been taken out at the point of sale. It also states that stoves between 2.5 g/hr and 7.5 g/hr can get a NOASH, whereas page 37 implies that a stove must be <2.5 g/hr to be eligible for a NOASH.

Page 47: Measure 33 in Klamath County and Feather River is more stringent than what exists in Fairbanks now. Fairbanks allows open burning without a permit when there is no stage restriction. Alaska DEC prohibits open burning between November 1 and March 31, but the air quality plan makes it clear that the state relies on the Borough to carry out the air quality program in Fairbanks. The fact that the local borough does not require a permit for open burning outside of curtailments makes this measure less stringent in Fairbanks than in other locations. In addition, Fairbanks does not curtail warming fires during a Stage 1.

Page 48: Measure 34 is less stringent in Fairbanks than in Klamath County. Uncertainty in weather forecasting means that Stage 1 alerts are not called correctly all the time, and not

everyone is aware of when an alert is in effect. It is much simpler and less prone to error to prohibit burn barrels and outdoor burning devices entirely.

Page 57: Measure 46 review curtailment exemptions. The current Fairbanks curtailment exemption "These restrictions shall not apply during a power failure." should be reviewed to clarified that it only applies to homes reliant on electricity for heating. As currently written, it appears overly broad.

Page 68: Measure R7, Ban Use of Hydronic Heaters, incorrectly identifies that no other SIPs implemented the measure as rational for not evaluating.

Page 72: Measure R15 is technologically feasible.

Page 78: It may help to make a section break or Section 2 label for "Analysis of Marginal / Unquantifiable Benefit BACM Measures

Page 81-83: The discussion of Measure 6 may need additional documentation. Anecdotal evidence is that damping is common in Fairbanks and is potentially a bigger source of pollution than not having a damper at very cold conditions. If installation by a certified technician addresses this issue, that should be documented.

Page 84: The quote, "did not know if the rule had worked well" needs a reference. It is also not clear of how relevant that is. It could be implemented well in Fairbanks and the fact that it may not have worked well in another location does not make it technologically infeasible for this location.

Page 85-86: While qualitative assessments are helpful to provide context, a quantitative assessment will be necessary to evaluate the measures as BACM and MSM.

Page 88: There are references to Fairbanks in the conclusion for Measure 17, but the analysis refers to AAC code.

Page 89: There appears to be missing text in the Background section related to Method 9.

Page 91: Measure 23 could consider the solution that the decals could be reflective and would be seen by vehicle headlights. Measure 23 could also consider that the decals are used by neighbors to determine who is or is not in compliance. This may be helpful as citizen compliance assistance efforts could supplement the Borough enforcement program.

Page 98-100: Measure 40 needs to include a discussion of all the areas listed on page 22. In addition, if a date certain measure or if Measure 29 were instituted, Measure 40 would essentially be achieved.

Page 114: Measure R5 describes a similar rule in Utah but lists "none" under implementing jurisdictions. Please make consistent.

ULS Heating Oil

Page vii and Page 16: Please check your information on the percentage of households who have a central oil fired furnace. Please consult ADEC's contractor for the emissions inventory and home heating surveys about (1) the percentage of homes that heat only with an oil furnace, and (2) home with a central oil burner and a wood stove. We have seen different numbers than presented here.

Page 13: Please check the labels for Fairbanks HS #2 and Fairbanks HS #1. They may be switched.

Page 14: The statement that there is "a clear explanation" may not be correct, or at minimum is an overstatement. The difference in price between HS#1 and ULSD has varied over time, and the report did not include an explanation for the variations.

Page 14: The third paragraph assumes that the capital costs of shipping ULS would be more than exists today. However, all heating oil is shipped, regardless of sulfur content, and there is no justification for the report for why shipping ULS would be higher than for HS. Additionally, it is possible that the shipping cost per unit could go down marginally if only one product is being supplied to Fairbanks and/or if the quantity supplied increases.

Page 21: The text and Table 7 present inconsistent information. For instance, the text says that the discounted net-present value of scenario 2 is $10,232 while the table says it is $5,768.56.

AURORA ENERGY

November 1, 2018

Alaska Department of Environmental Conservation
Division of Air Quality
ATTN: Director
410 Willoughby Avenue, Suite 303
Juneau, Alaska 99811-1800

Subject: Second Request for Additional Information for the Best Available Control Technology Technical Memorandum from Aurora Energy, LLC (Aurora) for the Chena Power Plant

Dear Ms. Koch,

Thank you for the opportunity to provide additional information to better characterize Aurora's operations for the Best Available Control Technology (BACT) Analysis which will be a part of the Serious Area State Implementation Plan.

The following is being provided in response to the information request letter dated September 13, 2018. The ADEC letter included an enclosure with twelve comments for which additional information was requested. Each comment is summarized below followed by a response from Aurora. The information is being submitted to the ADEC by November 1, 2018 as requested.

1. Alternative Fuel Source - Evaluate alternative coal sources as a potential control option for the coal-fired boilers and identify energy, environmental, and economic impacts and other costs that would affect the selection of an alternative source of coal as a technically feasible control option. Evaluate the control efficiency of alternative coal sources based on a comparison of the coal's heat content as well as nitrogen and sulfur content.

   Response: There are no other economically viable coal options for Aurora. Usibelli Coal Mine is the state's only operating coal mine.

2. Low Excess Air (LEA) and Overfire Air (OFA) - Evaluate these technically feasible control technologies using EPA's top down approach.

   Response: Aurora's BACT analysis dated March of 2017, Section 2.3.2, references the use of combustion controls, including OFA and LEA. The BACT analysis concludes that the Unit 5 (EU 7) is already equipped with OFA, LEA (i.e., oxygen trim system), and air preheaters. It is stated within the BACT that Units 1, 2, and 3 (EU 4-6) have OFA and air preheaters. Although the air preheater ductwork is installed, the preheaters have been removed from operation. The current

configuration of the traveling-grate boilers as installed, includes a 'partial' LEA (i.e., oxygen trim system). The fuel feed rate and oxygen for Boiler Units 1-3 (EU 4-6) are manually adjusted and tuned daily. The traveling-grate boilers have a knife gate which sets the bed thickness and the air-to-fuel ratio is manually adjusted to accommodate the boiler's performance. Once adjusted, the fuel-to-air ratio is maintained automatically.

3. Additional SO_2 Control Technologies - The BACT analysis does not include a substantive analysis of spray-dry scrubbing, dry flue gas desulfurization, dry scrubbing, or dry sorbent injection (DSI). All of these technologies have the potential to offer SO2 removal, and therefore must be included in the analysis.

   Response: - An addendum to the initial BACT submittal was provided to the State on December 22, 2017. This addendum included a substantive analysis of Spray Dry Absorbers (SDA) and Dry Sorbent Injection (DSI) technologies.

4. BACT Limits - Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for pollutant for each emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

   Response: Statements concerning applicable standards under 40 CFR Parts 60 (New Source Performance Standards—NSPS) and 61 (National Emission Standards for Hazardous Air Pollutants—NESHAP) are not relevant to the Chena boilers. The NESHAP do not regulate criteria air pollutants such as SO_2, and therefore, no SO_2 floor can be defined by any NESHAP. Furthermore, the Chena boilers are not subject to NSPS and therefore are not required to achieve the NSPS standard. In any case, the NSPS SO_2 emission limit of 1.2 lb/MM Btu (for units less than 75 MM Btu/hr) is achieved in the small boilers (the percent reduction is not a requirement for units less than 75 MM Btu/hr).

   An NSPS or NESHAP standard must be considered as the floor for BACT only when a source is subject to one of the standards. In that case, a source must achieve compliance with the NSPS or NESHAP, and a less stringent emission limit cannot be considered BACT. As noted in a July 28, 1987 memo by Gary McCutchen, then Chief of the New Source Review Section of the US EPA:

   > "Since an applicable NSPS must always be met, it provides a legal "floor" for the BACT, which cannot be less stringent." (emphasis added). This statement implies that a source must first be subject to an NSPS for the standard to be considered the BACT floor.

   The Chena plant operates four coal-fired boilers: three at 76.8 MM Btu/hr (22.5 megawatt, MW) heat input and one at 254.7 MM Btu/hr (74.6 MW) heat input. If newly-constructed today, the three smaller units would be subject to an NSPS Subpart Dc limit of 1.2 lb SO_2/MM Btu, and the larger unit would be subject to an NSPS Subpart Da limit of 0.15 lb SO_2/MM Btu. On a Btu-weighted average basis, the overall NSPS limit would be 0.64 lb SO_2/MM Btu. The Chena boilers

currently combust low-sulfur coal, with emissions of 0.39 lb SO_2/MM Btu from the combined exhaust. This overall emission rate represents a 39% reduction from NSPS limits if the Chena boilers had been built today.

Regardless of the NSPS applicability to the Chena boilers, the history of rulemaking for small industrial, commercial, and institutional (ICI) boilers provides valuable insight into the definition of BACT for SO_2 from these units. The three smaller units, if constructed today, would be subject to NSPS Subpart Dc for small ICI boilers. As defined in the standard, ICI units smaller than 22 MW (75 MM Btu/hr) heat input are not subject to a percent reduction requirement in NSPS and instead may achieve compliance with NSPS through the use of low sulfur fuel. The rationale for this "exemption" is provided in the preamble to the proposed rule (54 *Federal Register* (FR) 24806, June 9, 1989) and the Background Information Document for the Promulgated Standards. As discussed in the Background Document:

> "Section 111 of the CAA requires standards to reflect application of the best demonstrated technology considering costs, nonair quality health and environmental impacts, and energy requirements. Section 111 also requires that for fossil fuel-fired steam generating units a percent reduction standard be established. Read together, this means that the Administrator is compelled to include a percent reduction standard unless the impacts associated with the requirements would be unreasonable....Imposing these high (capital and annualized) costs for the units (those less than 22 MW) was considered to be unreasonable when compared to the increase in emission reduction achievable be the percent reduction requirement on these units. Therefore, in keeping with the requirements of the CAA, the final standards will not require percent reduction for any units operating at less than a 55 percent annual capacity factor for coal or any unit with a heat input capacity of 22 MW (75 million Btu/hr) or less."

The passage presented above is the basis for the US EPA's definition of BACT for small ICI boilers less than 22 MW. This analysis therefore defines BACT for such units as an emission rate equal to or greater than 1.2 lb SO_2/MM Btu. In the proposed rule, US EPA further states that compliance with this NSPS limit/ BACT emission rate for units smaller than 22 MW (75 MM Btu/hr) can be achieved through use of low-sulfur fuels (see 54 FR 24793). For all practical purposes, the three smaller boilers at the Chena plant fall into this category, and therefore BACT is defined as an emission limit of 1.2 lb SO_2/MM Btu, achieved through combustion of low-sulfur coal. Furthermore, as illustrated above, the four boilers at the Chena plant collectively operate with an actual SO_2 emission level that is 39 percent less than the levels that would be required if all of the units were subject to NSPS.

5. Retrofit Costs - Provide detailed cost analyses and justification for difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analysis.

Response: The BACT cost analysis employed a retrofit factor of 2.0. The basis for this factor was the EPA Air Pollution Control Cost Manual, Sixth Edition. As discussed in the Cost Manual:

> "To quantify the unanticipated additional costs of installation not directly related to the capital cost of the controls themselves, engineers and cost analysts typically multiply the

> cost of the system by a retrofit factor. The proper application of a retrofit factor is as much an art as it is a science, in that it requires a good deal of insight, experience, and intuition on the part of the analyst…The magnitude of the retrofit factor varies across the kinds of estimates made as well as across the spectrum of control devices. At the study level, analysts do not have sufficient information to fully assess the potential hidden costs of an installation. At this level, a retrofit factor of as much as 50 percent can be justified. Even at detailed cost level (± 5 percent accuracy), vendors will not be able to fully assess the uncertainty associated with a retrofit situation and will include a retrofit factor in their assessments." (see page 2-28 in EPA/452/B-02-001)

As noted in the above citation, US EPA notes that a retrofit factor can be as high as 1.5, this partially supports the value selected for the Chena BACT cost analysis. The cost model employed during the BACT analysis (i.e., CUECost) suggests the following retrofit factors: 1.0 factor for a new facility, a 1.3 factor for a moderately difficult retrofit, and a 1.6 factor for a difficult retrofit. The user is also given the option to input his own retrofit factor based on plant-specific information. As noted by the Northeast States for Coordinated Air Use Management (NESCAUM) in a in a report entitled "Applicability and Feasibility of NOx, SO2, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers an independent researcher (Emmel) noted that:

> "this range (of CUECost retrofit factors) significantly understated the cost of retrofit for FGD and SCR technologies when applied to EGUs (i.e., electric generating units) less than 100 MW. Emmel also noted that on average, a retrofit factor of 1.45 was more reasonable and that the factor should even be higher when CUECost is applied to ICI boilers."

Two main factors impact selection of the retrofit factor for the Chena plant: space availability and equipment congestion. These two factors will require additional efforts for installation, equipment staging, and maneuverability during construction.

6. Baseline Emissions - Include the baseline emissions for all emission units included in the analysis. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). The baseline is usually the legal limit that would exist, but for the BACT determination.

Response: The Baseline Emission rate is not a legal limit. As stated in the U.S. EPA 1990 New Source Review Workshop Manual:

> "Calculating Baseline Emissions"
>
> The baseline emissions rate represents a realistic scenario of upper boundary uncontrolled emissions for the source. *The NSPS/NESHAP requirements or the application of controls, including other controls necessary to comply with State or local air pollution regulations, are not considered in calculating the baseline emissions.* In other words, baseline emissions are essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions. (emphasis added)"

Based on this guidance, the Chena baseline emissions were properly calculated and applied to the BACT analysis.

7. Factor of Safety - If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.

   Response: The current BACT analyses included operating as is, therefore a factor of safety was not included.

8. Good Combustion Practices - For each emission unit type (coal boilers, distillate boilers, engines, and material handling) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices.

   Response: Good combustion practices were not proposed. The operation of existing combustion controls (OFA & LEA) were determined to be BACT for NOx.

9. Interest Rate - All cost analyses must use the current bank prime interest rate. This can be found online at https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table). Please revise the cost analyses as appropriate.

   Response: Suggest that the State revise interest rate to prime (currently 5.25%) and equipment life to 10 years, not 15, due to corresponding short remaining lifespan of associated boilers.

10. Economic Analysis for Circulating Dry Scrubber (CDS) - Provide in the analysis: the control efficiency associated with CDS, captured emissions (tons per year), emissions reduction (tons per year), capital costs (2017 dollars), operating costs (dollars per year), annualized costs (dollars per year), and cost effectiveness (dollars per ton) using EPA's cost manual.

    Response: See attached memo "CDS v SDA Cost Comparison.pdf" for CDS analysis.

11. Review State's Spreadsheets – Review cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010.

    Response: Aurora has provided a review of the ADEC's cost effectiveness spreadsheets and inputs. Comments are included on the spreadsheets. Please reference documents "chena-so2-economic-analyses-adec-With ERM Comments.xlsm" and "chena-large-boiler-so2-economic-analyses-adec- With ERM Comments.xlsm"

12. Site-Specific Quotes Needed – The cost analyses, particularly for SO_2 control technologies, must be based on emission unit-specific quotes for capital equipment purchase and installation costs at each facility. These are retrofit projects which must be considered individually in order to obtain reliable study/budget level (+/- 30%) cost estimates which are appropriate to use as the basis for decision making in determining BACT.

Response: Included as attachments within this response are vendor quotes as well as a cost analysis for Dry Sorbent Injection (DSI). Due to time constraints, the consultant was able to provide a +50/-30 cost estimate. Please reference the enclosed documents, to include: "Aurora Energy Preliminary Opinion of Probable Cost.pdf"; "Aurora_DSI_Opinion_of_Probable_Cost_rev0.pdf"; "BACT Proposal No. 1899-R1.pdf"; and "Aurora_Chena_DSI_General Arrangement.pdf".

Below are a list of documents that are being provided as enclosures which are referenced within the responses given above. If there are any questions pertaining to the information provided, please contact David Fish at dfish@usibelli.com or 907-457-0230.

Sincerely,

David Fish
Environmental Manager

Enclosures:

1. CDS v SDA Cost Comparison.pdf
2. chena-so2-economic-analyses-adec--With ERM Comments.xlsm
3. chena-large-boiler-so2-economic-analyses-adec--With ERM Comments.xlsm
4. Aurora Energy Preliminary Opinion of Probable Cost.pdf
5. Aurora_DSI_Opinion_of_Probable_Cost_rev0.pdf
6. BACT Proposal No. 1899-R1.pdf
7. Aurora_Chena_DSI_General Arrangement.pdf
8. Unified Facilities Criteria (UFC) DoD Facilities Pricing Guide (ufc_3_701_01_c1_2018.pdf)
9. ufc_3_701_01_data_tables_may_2018.xlsx
10. NSPS ICI SO2 RE.docx
11. ICI Boilers 20081118 final_revised-Jan2009.pdf
12. EPA Air Pollution Cost Control Manual, sixth edition, January 2002, accessible at https://www3.epa.gov/ttncatc1/dir1/c_allchs.pdf

Cc:
Larry Hartig, ADEC/Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Denise Koch, ADEC/ Air Quality
Cindy Heil, ADEC/ Air Quality
Deanna Huff, ADEC/ Air Quality
Jim Plosay, ADEC/ Air Quality
Aaron Simpson, ADEC/ Air Quality
Buki Wright/ Aurora Energy, LLC
Rob Brown/ Usibelli Coal Mine, Inc
Tim Hamlin/ EPA Region 10
Dan Brown/ EPA Region 10
Zach Hedgpeth/ EPA Region 10

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November 1, 2018

David Fish
Environmental Manager
Aurora Energy, LLC
100 Cushman St.
Suite 210
Fairbanks, AK 99701-4674

RE: Qualitative Cost Comparison of Circulating Dry Scrubber Technology Versus Spray Dryer Absorbers

David:

Per your request Jason Smith and I have developed a comparison between the Circulating Dry Scrubber and Spray Dry Absorption technologies and the expected differences in total installed cost. Jason is an expert in SO_2 scrubbers having participated in the construction, startup, and commissioning of several installations over the course of his career.

The two commercially available semi-dry acid gas scrubbing processes consist of Spray Dryer Absorption (SDA) and Circulating Dry Scrubber (CDS). Both technologies, for industrial coal fired applications, employ an alkaline reagent of calcium hydroxide and fly ash, which is collected from the combustion process. The calcium hydroxide reacts with sulfur dioxide (SO2) and sulfur trioxide (SO3) of the flue gas to form calcium sulfite and calcium sulfate. The calcium sulfite and calcium sulfate, unreacted calcium hydroxide, and fly ash is collected downstream of the acid gas scrubbing process by a baghouse, and a considerable portion is “recycled,” back to the scrubber to offset reagent costs by utilizing available unreacted alkalinity of the fly ash. The fly ash particles also serve to increase the available surface area for reactions to occur. Both process also depend on the humidification of the flue gas. In general, the greater the humidification, the lower the alkalinity stoichiometry, which reduced reagent consumption. To prevent corrosion downstream of these scrubbers and promote the longevity of downstream equipment (namely fluework, particulate collection, and stack), the humidification is limited to operating above the saturation temperature, referred to as the approach temperature.

The humidification of the flue gas stream is an area where the SDA and CDS scrubbing processes diverge.

In the SDA process, water for humidification is delivered as a portion of the lime and ash constituents. The water, lime, and ash slurries are pumped through recirculation loops and fed to an atomization feed system. The slurry that is fed to the atomizer is then dispersed in a passing flue gas stream inside an absorber or scrubber vessel. Once dispersed in the flue gas, a chemical reaction occurs, and the gas stream is scrubbed of the SO_2 and SO_3 pollutants. Since the slurry reagent is pumped, the SDA process can sometimes leverage existing infrastructure such as existing particulate collection equipment. The ability to integrate a SDA system into an existing flue gas system serves to limit the capital outlay necessary for a targeted level of compliance. The potential to leverage existing infrastructure is dependent on

numerous factors such as existing equipment layout and condition, site spatial limitations, and original design parameters of the existing particulate collection equipment, just to name a few.

The humidification of the flue gas stream for a CDS scrubbing process is essentially decoupled from the hydrated lime and ash constituents. Water for gas humidification is mechanically atomized into the passing flue gas stream and the dry alkaline products are conveyed to the CDS vessel using air slide conveyors. Air slide conveyors utilize an air permeable fabric, which is stretched across a rectangular enclosure flow path, to aerate particulate material, and allow the force of gravity to covey the material down the sloped surface. The alkaline material and water injection typically occurs after a venturi assembly that increases the velocity of the passing gas stream to establish a fluidized bed of alkaline material. The flue gas then passes through this bed and is scrubbed of the SO_2 and SO_3. The use of air slides to convey the fly ash from the particulate collection device (typically a baghouse) back to the scrubber necessitates that the collector be placed at higher elevations. This will ensure that the proper slope is maintained between the collector and the injection point on the absorber tower. It is technically challenging to take an existing collector and elevate it, so CDS technologies are typically purchased with an absorber vessel, air slides, particulate collection device, and waste ash systems. This allows the integration of the required elevation differences and the steel and foundations to accommodate the higher elevation construct to be handled under a single contract, thus limiting risk for the owner. Due to the additional equipment, steel, and deep foundations necessary, these factors typically increase the necessary capital outlay for the CDS technology.

Additional information on both SDA and CDS technology can be found in Chapter 34 of *STEAM, Its Generation and Use, 42nd Edition*, Babcock and Wilcox, Inc. Reference Figure 10 on Page 34-15 for an illustration of a typical SDA installation and Figure 17 on Page 34-21 for an illustration of a typical CDS installation.

The information above indicates that CDS and SDA technologies are similar in their nature and operation. However, the installation of a CDS frequently requires the installation of a new particulate collector, where the SDA system does not. The CDS equipment itself, along with the additional equipment needed for proper operation, will result in a significantly larger installation cost when compared to an equivalent SDA system. Given that the ADEC Preliminary BACT Determination for the Chena Plant (Dated March 22, 2018) has already established that a SDA system is not economically feasible (Table 4-3, Page 12), it can therefore be concluded that the CDS system is economically infeasible as well.

Please let me know if you have any questions or comments regarding the information presented in this letter.

Sincerely,

John P Solan

John P. Solan, P.E.
Senior Mechanical Engineer
Stanley Consultants, Inc.

cc: File

STANLEYCONSULTANTS, Inc

8200 South Chester Street ❯ Suite 500 ❯ Centennial, CO 80112
303.799.6900 ❯ stanleyconsultants.com

October 30, 2018

David Fish
Environmental Manager
Aurora Energy, LLC
100 Cushman St.
Suite 210
Fairbanks, AK 99701-4674

RE: Preliminary Opinion of Probable Cost for Addition of Dry Sorbent Injection

David,

This letter serves to document the preliminary results of our opinion of probable cost for the installation of a Dry Sorbent Injection (DSI) System at the Aurora Energy Chena Plant for the control of Sulfur Dioxide (SO_2) emissions.

Background

The US Environmental Protection Agency (EPA) has recently reclassified portions of the Fairbanks North Star Borough as a Serious PM 2.5 Non-Attainment Area. This reclassification triggers a requirement that all major sources within the non-attainment area perform a BACT analysis for particulate emissions and the emissions of any precursor pollutants. In response to this requirement Aurora Energy submitted the required BACT report to the Alaska Department of Environmental Conservation (ADEC) in March of 2017. An addendum to the report was submitted in December of that year.

After reviewing the data and conclusions presented in the BACT report, ADEC conducted their own analysis and presented their results as a Preliminary BACT Determination in March of 2018. The results developed by ADEC as a part of their analysis were significantly different from the results presented in the BACT report submitted by Aurora Energy.

Project Scope

Given the disparity in the results of the analyses, Aurora Energy has hired Stanley Consultants to develop a site-specific, third-party estimate of the costs to install SO_2 emissions control equipment on the four operating boilers at the Chena Combined Heat and Power Plant near downtown Fairbanks. Stanley Consultants will also provide an estimated sorbent consumption rate and a cost for the purchase and delivery of sorbent to site. Once these costs have been developed, Aurora Energy and their environmental consultants, ERM, will incorporate the estimated costs into a calculation to determine the cost effectiveness of the emissions control equipment on a Dollars/Tons of SO_2 removed basis.

This letter serves to document the preliminary Opinion of Probable Cost results so that Aurora Energy can submit a response to the BACT Determination ahead of a November 1, 2018 deadline. The information included herein relates only to the installation of a DSI system on the existing boilers. All performance information, quantities, and costs are preliminary and are

subject to revision as the cost estimate is refined and finalized. Additional clarifications as to the basis of the cost estimate and the anticipated performance are included below.

Design Basis

Boiler Performance and Flue Gas

Boiler heat input, flue gas flows, and uncontrolled SO_2 emissions rates from the previous reports were utilized to determine equipment sizes and required sorbent feed rates.

Dry Sorbent Unloading, Storage, Preparation, and Injection System

Equipment and piping costs for the Dry Sorbent Injection Systems were developed by BACT Process Systems, Inc. BACT supplied the DSI system that was recently installed at Elmson AFB, and therefore was already familiar with the emissions from burning Healy coal in stoker-type boilers. The BACT proposal includes:

- Sorbent unloading equipment suitable for transporting sodium bicarbonate from a railcar to a bulk storage silo. This equipment includes unloading blowers, coolers, piping and piping components.
- Two bulk storage silos with a total storage capacity that is sufficient for four months of continuous full load operation.
- Sorbent transfer equipment for moving the sorbent from the bulk storage silos to the day bins located in a sorbent preparation building including transport blowers, coolers, and associated piping
- Sorbent mills for optimizing the particle size of the sorbent prior to injection into each boiler flue
- Sorbent injection equipment including filter receivers, airlock feeders, blowers, coolers, and piping up to the wall of the sorbent preparation building.
- Sorbent injection lances
- Dedicated PLC's for the control of all equipment included in the proposal
- Engineering to facilitate the integration of the sorbent control system into the plant control system
- Computational Fluid Dynamics (CFD) of each flue to confirm predicted sorbent effectiveness

Additional equipment or systems that are required for proper operation of the DSI system, but was not included in the BACT proposal have been included separately in the cost estimate. This includes:

- Piping between the sorbent preparation building and the injection lance on each flue
- Additional ductwork on Boiler 5 to increase sorbent resonance time prior to the baghouse
- Electrical feeds and equipment required to support the BACT equipment
- Foundations
- Sorbent preparation building and interior structures
- Miscellaneous steel and supports

Equipment Layout

The cost estimate is based on the following approximate equipment locations:

- Unloading Equipment – Adjacent to the unloading building on the north side of Phillips Field Road
- Bulk Storage and Transfer Equipment – Adjacent to the existing coal pile on the south side of Phillips Field Road.
- Sorbent Preparation Building – Adjacent to the existing baghouse

See the attached sketch for additional information on the proposed equipment locations and interconnecting piping.

Opinion of Probable Cost

Based on the information above, the current estimate of probable cost is as follows:

Total Installed Cost: $20.682MM

Sorbent Cost: $550/Ton, Delivered

Reference the attached spreadsheet for additional information relating to the equipment and construction costs used. Total installed costs include probable costs for engineering, procurement and construction of the DSI system. It also includes mobilization and indirect contractor costs such as bonding, overhead, and profit. Finally, the Total Installed Cost includes an escalation factor to account for inflation and other cost increases over the construction period.

Clarifications

- The estimated accuracy of this Opinion of Probable Costs is +50% and -30%. The accuracy is expected to improve as the cost estimate is refined.
- Sorbent consumption numbers and equipment sizing were developed based on typical performance characteristics. These characteristics are typical of a flue gas system that operates at or near 500 degrees F and has sufficient duct length ahead of a baghouse to ensure at least 2 to 3 seconds of resonance time for the sorbent. The flue gas streams from the Chena boilers operate at significantly lower temperatures (300 to 350 degrees F). The potential reduction in sorbent performance due to the existing flue gas temperatures has not yet been evaluated. Adjustments to the maximum capture rate or sorbent feed rate may be determined to be necessary as the preliminary design develops.
- The costs included in this estimate are based on the best information that we have been able to obtain to-date. The refinement of existing costs or the inclusion of additional direct or indirect costs may be determined to be necessary as the preliminary design develops.
- Sorbent pricing information provided by BACT in their equipment proposal was supplied by the sorbent vendor based on a proposal from the year 2000. Stanley Consultants is aware of sorbent pricing from other operators in the region, but we have not been given explicit permission to identify the price or the plant in question. The price identified above is our best estimate for current pricing based on the information that we have available today.

Conclusion

The preliminary Opinion of Probable Cost presented in this letter is our current best estimate for the costs associated with the procurement and installation of a DSI system at the Chena Combined Heat and Power Plant. The estimate attempts to account for many of the site-specific factors that may negatively impact the actual capital costs including, plant configuration, site layout, seismic considerations, existing infrastructure, and local construction cost factors.

We hope the information presented in this letter meets your immediate needs and we look forward to providing you with a final Opinion of Probable Costs along with supporting documentation in the near future.

Thank you for the opportunity to assist Aurora Energy in this matter.

Sincerely,

John Solan
Senior Mechanical Engineer
Stanley Consultants, Inc.

cc: File

Attachments: DSI Equipment Layout Sketch

Opinion of Probable Cost Tabulation

		Rev. 0	Job No.	28709.01.00	Page No. 1
			Subject	Aurora Energy Chena - Dry Sorbent Injection	
Computed by	J. Smith / S. Worcester/ D. Bacon	Date 10/29/2018		Opinion of Probable Cost	
Checked by	J. Solan	Date 10/29/2018			
Approved by	C. Spooner	Date 10/30/2018	Sheet No.	1 of 1	

Item Description		Quantity		Unit Cost	Total Cost
		No. of Unit	UOM		
Engineering Services					
Engineering services provided throughout the project to assist with BOP design, technical specifications, procurement, bid evaluation, and construction observation.		1	EA	$1,880,200.00	$1,880,200
Dry Sorbent Injection System Supply					
DSI	Includes Railcar offloading, long term storage silos, day storage silos, milling, metering and feed.	1	EA	$4,900,000.00	$4,900,000
DSI Installation	Field Installation	1	EA	$6,370,000.00	$6,370,000
DSI Equipment Freight	FOB jobsite	1	EA	$200,000.00	$200,000
Structural					
Silo Foundation		2	EA	$244,304.00	$488,608
Sorbent Building Substructure		1	EA	$247,047.00	$247,047
Sorbent Building Superstructure		1	EA	$183,067.00	$183,067
Sorbent Building Exterior Closure		1	EA	$160,334.00	$160,334
Roofing		1	EA	$12,149.00	$12,149
Railcar Unloading Skid Foundation		5	CY	$650.00	$3,250
Transfer Skid Enclosure Foundation		5	CY	$650.00	$3,250
MCC Foundation		4	CY	$650.00	$2,600
Pipe Bridge by Silos - Steel	coal yard front end loader drive under.	4	TONS	$9,000.00	$36,000
Pipe Bridge by Silos - Foundations		6	CY	$650.00	$3,900
Outside Pipe Supports - Steel		10.0	TONS	$9,000.00	$90,000
Outside Pipe Supports - Foundations		40	CY	$650.00	$26,000
Inside Pipe Supports - Steel		3.00	TONS	$9,000.00	$27,000
Ductwork	100' Feet of Ductwork for Residence Time prior to PJFF	12.50	TONS	$10,300.00	$128,750
Mechanical					
Unit 1 Aggregate Piping Cost: 6" Sch 80 Pipe/Fittings/Flanges/Supports - Sorbent Prep to Injection Location		300	LF	$238.00	$71,400
Unit 2 Aggregate Piping Cost: 6" Sch 80 Pipe/Fittings/Flanges/Supports - Sorbent Prep to Injection Location		310	LF	$239.00	$74,090
Unit 3 Aggregate Piping Cost: 6" Sch 80 Pipe/Fittings/Flanges/Supports - Sorbent Prep to Injection Location		280	LF	$239.00	$66,920
Unit 5 Aggregate Piping Cost: 6" Sch 80 Pipe/Flanges/Supports - Sorbent Prep to Injection Location		200	LF	$239.00	$47,800
Electrical					
480V MCC	Mtl & Labor	2	EA	$65,177.00	$130,354
480V Panelboard and Xfmr	Mtl & Labor	2	EA	$10,200.00	$20,400
Cable - 480V - MCC, Loads	Mtl & Labor	9000	LF	$14.83	$133,436
Conduit - RGS	Mtl & Labor	6800	LF	$20.26	$137,748
Cable Terminations (Mat'l)	480V Material & Labor	496	EA	$26.11	$12,950
Light Fixtures Interior/Exterior	Surface mounted LED light fixtures (Mtl & Labor)	20	EA	$1,561.00	$31,220
Ground Grid extension	Mtl & Labor	1050	LF	$13.43	$14,100
Instrumentation & Controls					
BOP DCS Aspects		1	EA	$76,428.00	$76,428
All Terrain Forklift	45' lift, 35' reach, 9000 lb. capacity	12	WK	$6,455.00	$77,460
Hydraulic Crane	80-ton	90	DY	$4,365.00	$392,850
				Furnish and Erection Subtotal	$14,169,111
				Mobilization & Demobilization - 5%	$708,456
				Bond - 2.5%	$354,228
				Contractor Overhead - 10%	$1,416,911
				Contractor Profit - 10%	$1,416,911
				Total Construction Cost	$18,065,617
	Escalation Percent 4.00%	Periods 14		Escalation (Nov 2018 - January 2020)	$736,199
				PROBABLE EQUIPMENT & CONSTRUCTION COST	$18,802,000
				PROBABLE ENGINEERING, EQUIPMENT & CONSTRUCTION COST	**$20,682,000**

Note: All costs presented in this document are Stanley Consultants' opinions of probable project, construction, and/or operation and maintenance costs. This estimate of probable construction cost is based on our experience and represent our best judgment. We have no control over cost of labor, materials, equipment, contractor's methods, or over competitive bidding or market conditions. Therefore, we do not guarantee that proposals, bids, or actual construction costs will not vary from estimates of project costs, construction, and/or operation and maintenance costs presented. The costs identified are based on Means Building Construction Cost Data, Engineering News Record Construction Cost Index, and/or vendor quotes.

BACT PROCESS SYSTEMS, INC.

3345 N. ARLINGTON HEIGHTS RD., SUITE B
ARLINGTON HEIGHTS, IL 60004-1900
(847) 577-0950
FAX: (847) 577-6356
E-MAIL: bact_process@sbcglobal.net

November 1, 2018

Mr. John Solan, P.E.
Senior Mechanical Engineer
Stanley Consultants
8000 S. Chester Street, Suite 500
Centennial, CO 80112

RE: DSI for Aurora Energy / BACT Proposal No. 1899-R1

Dear John,

We are revising our proposal in the light of your comments. The Emissions and sorbent usage from the boiler is based on recent information from you: on 0.39 lbs. of SO2/MBTU these calculations are based on using a weight ratio of 2.6 lbs. of sodium bicarbonate to 1 lb. of sulfur and a NSR of 1.3: Sulphur at .28%: Heating Volume of 7,600: 80% removal of SO2.

BOILER	MBTU/HR	SO2 PPH	SODIUM BICARBONATE PPH
1	76	29.64	100
2	76	29.64	100
3	76	29.64	100
4	269	139.88	400
		TOTAL 228 PPH	700 PPH
			0.35 Tons/Hr.
	Per Month:	8.4 Tons/Day	252 Tons

Bicarbonate Storage

For four months; we need 756 Tons of sorbent
(2) Silos: 518 Tons capacity each
TOTAL CAPACITY = 1,036 Tons
Silo Size: Same as Eielsen

Cost of Sodium Bicarbonate = $123,480 per month; this is based on estimate by Solvay for year 2000 delivery: $250 plus, $240 freight.

Scope of Supply

1. (2) Bolted Storage Silos – 22' DIA x 100' tall with bin-vent level control and bin vibrators; capacity = 1,036 tons; storage silo complete.
2. (1) Rail car unloading and diverters to fill silos located 500' away; rate = 33,000 PPH, blower = 200 HP; installed spare; backup blower.
3. (3) Day bins with pneumatic conveying from storage silos. Conveying distance 1,000', 6,000 PPH capacity, blower = 200 HP; blowers are spared.
4. (3) Classifier mills; 1,000 PPH capacity, 75 HP total, connected HP (for 2). The 75 HP is the sum of the grinding motor, classifier motor, brakes, and VFD.

5.&6. (3) Filter receivers with conveying blowers. Milled material conveying material from mill to filter receivers. (2) Blowers 75 HP total; total connected.

7. (4) Injector sets to be installed on duct work.
8. (1) Dedicated compressor.
9. (1) NEMA 6 control panel with microprocessor.
10. Integration to the boiler control panel.
11. CFD modeling and programing.
12. All pneumatic piping up to the reagent building. All piping within the sorbent prep building by BACT. Pipe from the building wall for the 4 pipes leading to each stack by customer. Air coolers are provided to minimize puffing of the reagent.
13. Sorbent building and foundation by customer.

Budget Sell Price: $4,200,000
Freight: $ 200,000
F.O.B. Shipping Point
Taxes Extra

If you have any questions, please let me know.

Best regards,

BACT PROCESS SYSTEMS, INC.

N.S. ("Bala") Balakrishnan
President


Aurora Energy LLC
Chena CHP Plant
N
Sorbent Railcar Unloading Skid
Pipe & Power thru Utilidor (under road).
Sorbent Storage Silos
Sorbent Prep Enclosure
Unit 5 Injection
Unit 1 Injection
Unit 2 Injection
Unit 3 Injection
Google
© 2018 Google
300 ft

UFC 3-701-01
23 May 2018
Change 1, 25 June 2018

UNIFIED FACILITIES CRITERIA (UFC)

DoD FACILITIES PRICING GUIDE



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U.S. ARMY CORPS OF ENGINEERS

NAVAL FACILITIES ENGINEERING COMMAND (Preparing Activity)

AIR FORCE CIVIL ENGINEER CENTER

Record of Changes (changes are indicated by **1**\ ... /**1**/)

Change No.	**Date**	**Location**
1	6-25-18	Update Table 3 with RUC. Text update 3-2.

This UFC supersedes UFC 3-701-01, dated March 2011.

FOREWORD

The Unified Facilities Criteria (UFC) system is prescribed by MIL-STD 3007 and provides planning, design, construction, sustainment, restoration, and modernization criteria, and applies to the Military Departments, the Defense Agencies, and the DoD Field Activities in accordance with USD (AT&L) Memorandum dated 29 May 2002. UFC will be used for all DoD projects and work for other customers where appropriate. All construction outside of the United States is also governed by Status of Forces Agreements (SOFA), Host Nation Funded Construction Agreements (HNFA), and in some instances, Bilateral Infrastructure Agreements (BIA.) Therefore, the acquisition team must ensure compliance with the most stringent of the UFC, the SOFA, the HNFA, and the BIA, as applicable.

UFC are living documents and will be periodically reviewed, updated, and made available to users as part of the Services' responsibility for providing technical criteria for military construction. Headquarters, U.S. Army Corps of Engineers (HQUSACE), Naval Facilities Engineering Command (NAVFAC), and Air Force Civil Engineer Center (AFCEC) are responsible for administration of the UFC system. Defense agencies should contact the preparing service for document interpretation and improvements. Technical content of UFC is the responsibility of the cognizant DoD working group. Recommended changes with supporting rationale should be sent to the respective service proponent office by the following electronic form: Criteria Change Request. The form is also accessible from the Internet sites listed below.

UFC are effective upon issuance and are distributed only in electronic media from the following source:

- Whole Building Design Guide web site http://dod.wbdg.org/.

Refer to UFC 1-200-01, *DoD Building Code (General Building Requirements)*, for implementation of new issuances on projects.

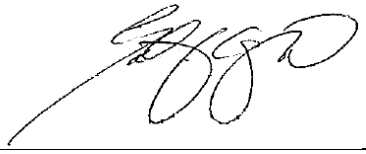
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UNIFIED FACILITIES CRITERIA (UFC)
[REVISION] SUMMARY SHEET

Document: UFC 3-701-01, *DoD Facilities Pricing Guide*

Superseding: UFC 3-701-01, dated March 2011

Description: The document provides updated cost and pricing data in support of facility planning, investment and analysis needs.

Reasons for Document:

- This UFC provides updated cost and pricing data intended to support preparation of the DoD budget.

Impact:

- Provides consistency across the DoD for the development of budgets for military construction projects.

Unification Issues

None

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CHAPTER 1 INTRODUCTION

1-1 PURPOSE AND SCOPE.

The DoD Facilities Pricing Guide supports a spectrum of facility planning, investment, and analysis needs. This version of the Guide reflects updated cost and pricing data for FY 2018 intended to support preparation of the DoD budget for FY 2020. It includes reference information organized into three chapters, as follows:

1-1.1 Chapter 2: Unit Costs for Military Construction Projects.

Chapter 2 describes the usage of facility unit cost data for selected DoD facility types in support of preparing Military Construction (MILCON) project documentation (DD Forms 1391) and other program-level estimates in accordance with UFC 3-730-01, "Programming Cost Estimates for Military Construction."

1-1.2 Chapter 3: Unit Costs for DoD Facilities Cost Models.

Chapter 3 describes the usage of unit costs in support of DoD facilities cost models. These unit costs are based upon the reported average DoD facility size or an established benchmark size, as annotated for each Facility Analysis Category (FAC) in the DoD Real Property Classification System (published separately). These unit costs are intended for macro-level analysis and planning rather than individual facilities or projects.

1-1.3 Chapter 4: Cost Adjustment Factors.

Chapter 4 describes the usage of cost adjustment factors for location and price escalation that are applicable to the base unit costs in both Chapters 2 and 3.

1-2 APPLICABILITY.

This UFC applies to all projects in both the continental US (CONUS) and outside the continental US (OCONUS).

1-3 DATA TABLES.

All data tables in this UFC are found in a combined file under "Related Materials" accompanying this UFC on the (WBDG) Web site:
https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01.

1-4 PROPONENT.

The Office of the Assistant Secretary of Defense for Energy, Installations, and Environment is the proponent for the Facilities Pricing Guide. Recommendations from users toward improving the usefulness of this reference are welcome.

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CHAPTER 2 UNIT COSTS FOR MILITARY CONSTRUCTION PROJECTS

2-1 OVERVIEW.

The facility unit costs in this chapter apply to preparation of programming-level cost estimates for constructing military facilities in accordance with the methodology described in UFC 3-730-01.

All data tables in this UFC are found under "Related Materials" in a combined file accompanying this UFC on the (WBDG) Web site:
https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01.

2-2 FACILITY UNIT COST TABLE.

Table 2 provides facility unit costs for various DoD facility types in dollars per square meter ($/SM) and equivalent English unit cost data in dollars per square foot ($/SF) as of October 2017. The listed facility types represent only those facilities most frequently constructed by the Military Services, and the application of a facility unit cost may not be directly applicable for those facilities with unique requirements. See UFC 3-730-01 for additional guidance on facility unit costs and their application.

The unit costs in Table 2 are average unit costs for new construction based on no less than three project awards per building type occurring since September 2014 for Army, Navy, Air Force, Defense Education Activities (for school projects) and Defense Health Agency (for medical projects) facilities as entered into the Historical Analysis Generator (HII) unit cost database prior to 1 Nov 2017. Facility additions which are less than 25% of the Reference Size of the listed facility type, and projects outside of the continental United States (OCONUS), are included only for Family Housing and DoD Schools. For additional information regarding how the facility unit costs are determined, refer to paragraph 2-3, Guidance Unit Cost Development.

2-3 GUIDANCE UNIT COST (GUC) DEVELOPMENT METHODOLOGY.

2-3.1 Data Source.

The data source for the facility unit costs is all reliable HII project records, after excluding records for reasons stated in paragraph 2-2. In general, all project records for the CONUS and projects from Alaska and Hawaii are included.

Facility level information from all three Services projects is entered into HII database for comparable service category codes (CATCODEs). Normalized project unit costs are statistically analyzed to eliminate outliers before calculating the guidance unit cost (GUC).

2-3.2 Business Rules.

The business rules are reviewed annually prior to updating Table 2 Facility Unit Costs for Military Construction. The business rules include the following components.

- The Tri-Service CATCODEs Cross-walk table groups like service CATCODEs to a common Office of the Secretary of Defense (OSD) Code. OSD Codes are not published and are only utilized for this task of segregating data. A minimum of three projects are required within those defined years to create a dataset. If there is insufficient data available within the above three-year period, the dataset search is extended to the last four years.
- Projects are new construction only.
- Projects are located within the CONUS, plus Hawaii and Alaska, except where noted otherwise in Table 2.
- Projects with extreme variation from the mean (50%) are excluded., and
- Exclusion of inappropriate data for cause.

2-3.3 Data Normalization.

Each facility-specific data set is normalized to the National Average Area Cost Factor (ACF=1) and number of bidders, and escalated to October of the year of interest, before unit costs are averaged.

- Escalation: The DoD Selling Price Index (DoD-SPI), which is an average of three commonly accepted national construction price escalation indices, is utilized to escalate actual project award cost data to October of 2017 for this UFC,
- Number of Bidders: Based on actual bid data for the data set,
- Location: Normalize each project award by the appropriate ACF to the national average of 1.0, and
- Facility Size: Normalize each facility award amount in the dataset for facility size, using a normalization process that looks at the facility size as compared to the average facility size of the selected dataset by OSD code.

2-3.4 Primary Facility Included Costs.

The facility unit costs include the following:

- Minimum antiterrorism design features (reference UFC 4-010-01, “DoD Minimum Antiterrorism Standards for Buildings”) inside the building meeting Table B-1 standoff distance requirements,
- Sales tax on building materials,

- Building information system costs (e.g., conduits, racks, trays, telecommunication rooms) without any specialized communications requirements,
- Installed (built-in) building equipment and furnishings normally funded with MILCON funds,
- Energy Management Control System (EMCS) connections,
- Intrusion Detection System (IDS) infrastructure, including conduits, racks, and trays,
- Sustainable design and construction features - energy consumption reduction requirements mandated before 6 November 2016; and all other sustainable design features for criteria in effect from September 2014 thru September 2017 with the exception of renewable energy generation elements,
- Progressive Collapse premiums for the following specific facility types: Inpatient Hospital/Medical Center, Primary Care Clinic (Attached), Major Command Headquarters Building, Barracks/Dormitory, and Recruit Open Bay (Barracks), and
- Standard foundation systems (e.g. strip/spread footings, thickened edge slab for slab on grade).

2-3.5 Primary Facility Excluded Costs.

The unit costs do not include the following:

- Gross receipt taxes or gross taxes, gross excise taxes, or state commerce taxes,
- “Acts of God” or unusual market conditions,
- Supporting facility costs,
- Equipment acquired with other fund sources, including pre-wired workstations or furnishing systems, intrusion detection systems,
- Sustainable design and construction features - renewable energy generation elements; energy consumption reduction requirements mandated on or after 6 November 2016; and all other features mandated since September 2017; these will be estimated separately in accordance with component guidelines and documented on DD Form 1391 per DoD Instruction 4170.11, Installation Energy Management,
- Special foundations (e.g. pre-stressed concrete piles, caissons), intrusion detection system installation, base exterior architectural preservation guidelines,

- Enhanced Anti-Terrorism (AT) standards (exceeding the minimum in UFC 4-010-01, or when minimum standoff distances [Table B-1] are not achieved) construction contingency allowances,
- Cybersecurity costs,
- Supervision, inspection, and overhead (SIOH),
- Design costs (design-build contracts), and Construction cost growth resulting from user changes, unforeseen site conditions, or contract document errors and omissions.

2-3.6 Primary Facility Cost Considerations.

The following are cost considerations for primary facilities:

- Medical facilities: Unit costs include category A and category B equipment and building infrastructure for category C equipment,
- Housing for Unaccompanied Military Personnel: Unit costs for barracks, dormitories, and Unaccompanied Officers Quarters do not include free-standing kitchen equipment. In addition to using the size adjustment factors, use the project size adjustment factors in UFC 3-730-01,
- Child Development Centers: Unit costs do not include free-standing food service equipment or playground area and equipment,
- Family housing: Unit costs are based upon gross area and include sprinkler systems or fire-rated construction. Unit costs include post-award design costs,
- Reserve facilities other than reserve centers: Use the unit cost of the appropriate facility type, and
- Costs are independent of the acquisition strategy and are not specific to any single construction type.

CHAPTER 3 UNIT COSTS FOR DOD FACILITIES COST MODELS

3-1 OVERVIEW.

This chapter describes the unit costs and related factors used in support of DoD facilities cost models. These unit costs are intended for macro-level analysis and planning and are not reliable for individual facilities or project estimates.

Unit costs and related factors are associated with FACs represented by a 4-digit code in the DoD Real Property Classification System (RPCS), which is a hierarchical scheme of real property types and functions that serves as the framework for identifying, categorizing, and modeling the DoD's inventory of land and facilities. FACs are common across the department and suitable for department-wide applications. For each FAC, Table 3 identifies the associated unit cost to be used in DoD facilities cost models and metrics.

Whenever possible, unit costs and factors have been based upon approved government or commercial benchmarks. Detailed supporting data for unit costs is available, and accompanies this UFC on the WBDG Web site. All data tables in this UFC are found in a combined file under "Related Materials" accompanying this UFC on the (WBDG) Web site: https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01.

3-2 REPLACEMENT UNIT COSTS (RUC).

3-2.1 \1\ Definition and Use of Replacement Unit Costs. /1/

\1\ Replacement unit costs form the basis of calculating Plant Replacement Value (PRV) in a consistent manner across DoD, representing a complete and useable facility built to current DoD design standards. Replacement unit costs can also support large-scale program-level estimates for re-stationing plans with the addition of allowance for site preparation, earthwork, landscaping, and related factors. Replacement unit costs should not be used for individual project estimates. /1/

Replacement \1\ unit /1/ costs include construction of standard foundations, all interior and exterior walls and doors, the roof, utilities out to the 5-foot line, all built-in plumbing and lighting fixtures, security and fire protection systems, electrical distribution, wall and floor coverings, heating and air conditioning systems, and elevators. Replacement \1\ unit /1/ costs do not include project costs such as design, supporting facility costs, special foundations, equipment acquired with other funding sources (e.g. mission-funded components), contingency costs, or supervision, inspection, and overhead (SIOH). \1\ unit /1/ costs also do not include items that are generally considered personal property such as computer systems, and furniture. See paragraph 3-5, Revising Unit Costs, for guidance on requesting changes \1\ to replacement unit costs /1/in Table 3.

3-2.2 \1\ Plant Replacement Value (PRV). /1/

DoDI 4165.14 defines PRV as the cost to design and construct a notional facility to current standards to replace an existing facility on the same site. The factor values are provided in the "Report of the Plant Replacement Value (PRV) Panel, August 2001-May 2003" published by the Office of the Deputy Under Secretary of Defense (Installations and Environment). The standard DoD formula for calculating PRV is:

Equation 3-2 Calculating PRV

$$PRV = Q \times RUC \times ACF \times HF \times PD \times SIOH \times CF$$

Where:

PRV is plant replacement value

Q is facility quantity, in the same unit of measure as the RUC

RUC is replacement unit cost found in Table 3 of this UFC

ACF is area cost factor found in Table 4 of this UFC, to account for geographical differences in the costs of labor, materials and equipment

HF is an adjustment of 1.05 to account for increased costs for replacement of historical facilities or for construction in a historic district. The factor is 1.0, should the facility not qualify as "historical".

PD is a factor to account for the planning and design of a facility; the current value of this factor is 1.09 for all but medical facilities, and 1.13 for medical facilities.

SIOH is the factor to account for the supervision, inspection, and overhead activities associated with the management of a construction project. The current value of the factor is 1.057 for facilities in the (CONUS), and 1.065 (USACE) or 1.062 (NAVFAC) for facilities in the (OCONUS).

CF is a factor of 1.05 to account for construction contingencies

3-3 SUSTAINMENT UNIT COSTS (SUC).

3-3.1 Definition.

Sustainment provides for maintenance and repair activities necessary to keep a typical inventory of facilities in good working order over its expected service life. It includes the following:

- Regularly scheduled adjustments and inspections, including maintenance inspections (e.g., fire sprinkler heads, HVAC systems) and regulatory inspections (e.g., elevators, bridges),
- Preventive maintenance tasks,
- Emergency response and service calls for minor repairs, and
- Major repair or replacement of facility components (usually accomplished by contract) that are expected to occur periodically throughout the facility service life.

Sustainment includes regular roof replacement, refinishing wall surfaces, repairing and replacing electrical, heating, and cooling systems, replacing tile and carpeting and similar types of work as well as overhead costs which include architectural and engineering services. It does not include repairing or replacing non-attached equipment or furniture, or building components that typically last more than 50 years (such as foundations and structural members). Sustainment does not include restoration, modernization, environmental compliance, facility leases, specialized historical preservation, general facility condition inspections and assessments, planning and design (other than shop drawings), or costs related to Acts of God, which are funded elsewhere. Other tasks associated with facilities operations (such as custodial services, grass cutting, landscaping, waste disposal, and the provision of central utilities) are also not included.

3-3.2 Use of Sustainment Unit Costs.

Sustainment unit costs represent the annual average sustainment cost for each FAC, and serve as the basis for calculating annual facilities sustainment requirements for DoD using the following formula:

Equation 3-3 Calculating Sustainment Requirement

$$SR = Q \times SUC \times SACF \times I$$

Where:

SR is sustainment requirement

Q is facility quantity, in the same unit of measure as the SUC

SUC is sustainment unit cost found in Table 3

SACF is sustainment area cost factor found in Table 4

I is the value(s) representing future-year escalation for operation and maintenance accounts, published in Table 4-4.

The Sustainment Requirement for each qualifying asset in the DoD inventory is aggregated by sustaining organization and sustainment fund type in the Facilities Sustainment Model (FSM), published annually.

3-4 UNIT COST SOURCES.

Unit costs for DoD cost models are developed using a variety of sources. These sources fall into the three categories described below, listed in order of preference of use. The source description and source group for each unit cost are identified in Table 3. Supporting documentation for each unit cost calculation is available in the "Supporting documentation" file download accompanying this UFC document on the WBDG website: https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01.

3-4.1 Source 1 Published Data

Standard, easily-accessible published data that is highly applicable to the FAC. Source 1 is the most desirable due to ease of access, general applicability, and lack of bias. Examples include the DoD Tri-Service Committee on Cost Engineering, Service-specific cost guidance (USACE), commercial cost-estimating guidelines or models, or other Government-published cost guidance from federal, state, or local government agencies (e.g. Fairfax County (Virginia) Park Authority). Non-DoD source 1 data may require refinement for application in DoD, but is still considered source 1 if it closely matches the design attributes of the FAC.

3-4.2 Source 2 Similar Data

Data that is applied to facilities with similar but not identical characteristics (e.g., sewage waste treatment facilities and industrial waste treatment facilities). Source 2 also includes unpublished government or trade association cost data, and Component-validated costs for non-standard facilities that have no commercial counterparts (e.g. missile launch facilities or military ranges).

3-4.3 Source 3 Derived Data

Unpublished project-specific data derived from Component project documents (e.g. DD Forms 1391) or from calculating costs from reported Plant Replacement Value and inventory, or derived from using a ratio of sustainment to construction from a similar source 1 Facilities Analysis Category (e.g. FAC 2115, Aircraft Maintenance Hangar, Depot derived from FAC 2111, Aircraft Maintenance Hangar).

3-5 REVISING UNIT COSTS.

Users of this UFC are encouraged to suggest revisions to the published cost factors, particularly for facilities unique to their mission. Submit proposed changes to the proponent office in accordance with the following guidelines:

- Revised costs should come from an equivalent or superior source,
- Revised costs should be easily audited,
- Revised costs should be consistent with the functional definitions,
- Revised costs should be consistent with the FAC scope and
- Revised costs should be suitable for application throughout DoD.

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CHAPTER 4 COST ADJUSTMENT FACTORS

4-1 LOCATION ADJUSTMENTS.

Table 4-1 provides area cost factors (ACFs) to be used for adjusting “bare” unit costs to location-specific costs for the most common locations.

All data tables in this UFC are found in a combined file under “Related Materials” accompanying this UFC on the (WBDG) Web site: https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01.

4-1.1 Application

For military construction projects, use the MILCON ACFs with the primary facility unit costs from Chapter 2 or approved Air Force, Army, or Navy MILCON Pricing Guide. For calculating Plant Replacement Value, use the MILCON ACFs with the appropriate RUCs from Chapter 3. For calculating sustainment costs, use the sustainment ACFs with the appropriate SUCs from Chapter 3.

Do not use the MILCON ACFs to modify parametric cost estimates, detailed quantity-take-offs, unit price book (UPB) line items, commercial cost data, or user-generated unit costs. These cost estimating methods and databases have their own processes and factors for adjusting costs to different locations. MILCON ACFs or any component(s) that make up MILCON ACFs are only applicable to construction costs and should not be applied or utilized for any other purpose.

4-1.2 Data Source

In general, the Tri-Service Cost Engineering ACF software program evaluates the local costs for a United States market basket of eight labor crafts, 18 construction materials, and four equipment items. These labor, materials, and equipment (LME) items are representative of the types of products, services, and methods used to construct most military facilities in the United States. Each of the LME costs is normalized and weighted to represent its contribution to the total cost of a typical facility. The normalized LME is then modified by seven matrix factors that cover local conditions affecting construction costs. These matrix factors include weather, seismic, climatic (frost zone, wind loads, and HVAC systems), labor availability, contractor overhead and profit, logistics, and labor productivity and are relative to the U.S. standard. The resultant ACF for each location is normalized again by dividing by the 96-Base-City average to provide a final ACF that reflects the relative relationship of construction costs between that location and the 96-Base-City average as 1.00.

MILCON ACFs are calculated using a LME ratio of 35/63/2. Sustainment ACFs are calculated using a LME ratio of 53/46/1.

4-1.3 Survey

Both CONUS and OCONUS construction market surveys were conducted in 2017. The CONUS survey covered 300 locations that included 96 Base Cities (two per state in the continental U.S.). The OCONUS survey included 75 locations, and was based on a market basket of goods for typical U.S. labor, material, equipment, and construction methods.

CONUS and OCONUS surveys are performed annually. When local materials and construction methods differ from those represented by the published ACF, specific adjustments may need to be added to the project estimate to account for any differences. There is no easy correlation between the current MILCON ACFs and previous MILCON ACFs for specific locations. No common benchmarks exist because both the Base City average and the relationships between cities change with each survey. It is possible, however, to compare differences between several locations in this database with differences between the same locations in previous databases.

4-1.4 Force Majeure

The ACF is not intended to, or capable of, responding to rapid changes in the market place. Examples include Acts of God, accelerated construction schedules, changes in the demand and supply for construction materials, labor, and equipment. An increased demand for labor beyond what the local market can supply may require the enticement of premium pay, overtime hours, temporary living expenses, and travel expenses.

4-1.5 User Requested Revisions

Users may request revisions to published ACFs when market conditions unexpectedly change. Each request must be initiated by the USACE District senior cost engineer through HQUSACE or by the NAVFAC regional cost engineer to their corresponding NAVFAC Atlantic or Pacific Tri-Service Cost Engineering committee member. The local cost engineer shall provide updated market basket ACF software input factors with adequate backup documentation to HQUSACE or NAVFAC for them to update the Tri-Service Cost Engineering ACF software.

4-2 ESCALATION.

Tables 4-2, 4-3, and 4-4 provide escalation (inflation) factors used to adjust unit costs in Tables 2 and 3 (expressed in base-year dollars) to the desired year, as follows:

4-2.1 Military Construction.

Military construction project estimates that use unit costs from Table 2 should use the military construction escalation factor from table 4-2 for the expected midpoint of construction as described in UFC 3-730-01.

4-2.2 Plant Replacement Value Escalation Rates.

Plant Replacement Value (PRV) calculations that use replacement unit costs from Table 3 should use the escalation factor from Table 4-3 for the desired program year.

4-2.3 Facilities Sustainment.

Modeled facilities sustainment cost estimates that use unit costs from Table 3 should use the O&M escalation factor from Table 4-4 for the desired program year.

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APPENDIX A REFERENCES

UNIFIED FACILITIES CRITERIA

http://www.wbdg.org/ccb/browse_cat.php?o=29&c=4

UFC 3-730-01, *Programming Cost Estimates for Military Construction*

PLANT REPLACEMENT VALUE

https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01

Report of the Plant Replacement Value (PRV) Panel, August 2001 – May 2003, R&K Engineering, Inc. for the Office of the Deputy Under Secretary of Defense (Installations and Environment)

United States
Environmental Protection
Agency

Office of Air Quality
Planning and Standards
Research Triangle Park NC 27711

EPA-450/3-90-016
August 1990

Air

EPA

Small Industrial-Commercial-Institutional Steam Generating Units -- Background Information for Promulgated Standards

EPA-450/3-90-016

Small Industrial-Commercial-Institutional Steam Generating Units -- Background Information for Promulgated Standards

Emission Standards Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

August 1990

8.3.3 Percent Reduction Standard

1. Comment: Two commenters (IV-D-08, IV-D-28) requested that the 90 percent SO_2 reduction requirement be eliminated and replaced with an emission limit of 520 ng/J (1.2 lb/million Btu) heat input. One commenter (IV-D-08) objected to applying the 90 percent SO_2 reduction requirement to all coal regardless of sulfur content. This commenter stated that the EPA's conclusion that no units will be built in the size range between 22 and 29 MW (75 and 100 million Btu/hr) heat input capacity and operating at greater than 55 percent capacity factor is flawed. This commenter stated that the SO_2 standard of 520 ng/J (1.2 lb/million Btu) heat input for coal-fired plants should apply to all steam generating units in this source category, regardless of size. This commenter further recommended that the full 90 percent SO_2 removal be required only when the 520 ng/J (1.2 lb/million Btu) limit could not be met by using low sulfur coals or by pretreating the coals.

Another commenter (IV-D-28) stated that the 90 percent SO_2 reduction requirement should be removed and that coal-fired steam generating units in the 8.7 to 29 MW (30 to 100 million Btu/hr) range should be required only to meet the 520 ng/J (1.2 lb/million Btu) SO_2 limit. The commenter stated that the percent reduction requirement would place an unjustified cost and performance burden on units in this range that either already meet or are close to meeting the 520 ng/J (1.2 lb/million Btu) SO_2 limit.

Response: Section 111 of the CAA requires standards to reflect application of the best demonstrated technology considering costs, nonair quality health and environmental impacts, and energy requirements. Section 111 also requires that for fossil fuel-fired steam generating units a percent reduction standard be established. Read together, this means that the

Administrator is compelled to include a percent reduction standard unless the impacts associated with the requirements would be unreasonable. As discussed in the background document, "Model Boiler Cost Analysis for Controlling Sulfur Dioxide (SO_2) Emissions from Small Steam Generating Units" (EPA-450/3-89-14), a small coal-fired steam generating unit of 22 MW (75 million Btu/hr) size and operating at a 55 percent capacity factor has an incremental cost-effectiveness value of about $3,600/Mg ($3,300/ton) relative to an emission limit standard of 520 ng/J (1.2 lb/million Btu). Capital and annualized costs are projected to increase by approximately 20 percent over the regulatory baseline for the percent reductions standard. However, these values increase significantly for units less than 22 MW (75 million Btu/hr) heat input capacity and for any unit less than 29 MW (100 million Btu/hr) operating at an annual capacity factor for coal of less than 55 percent. Imposing these high costs for these units was considered to be unreasonable when compared to the increase in emission reductions achievable by the percent reduction requirement on these units. Therefore, in keeping with the requirements of the CAA, the final standards will not require percent reduction for any units operating at less than a 55 percent annual capacity factor for coal or any unit with a heat input capacity of 22 MW (75 million Btu/hr) or less.

Finally, no conclusion was made that coal-fired steam generating units greater than 22 MW (75 million Btu/hr) heat input and greater than 55 percent capacity factor would not be built. Rather, this was a projection of sales over the next five years based on sales trends over the past several years. The sales projections for coal-fired units had an influence on the conclusion of the reasonableness of the percent reduction requirement. (The assumption was used in generating national impacts of the standards.) The model steam generating unit analysis examined the potential impacts of the percent reduction requirement on a coal-fired unit greater than 22 MW (75 million Btu/hr) and greater than 55 percent capacity factor. Therefore, should a unit be built, requiring 90 percent reduction of emissions would be reasonable.

Applicability and Feasibility of NOx, SO_2, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers

Northeast States for Coordinated Air Use Management (NESCAUM)

November 2008
(revised January 2009)

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UNITS, SPECIES, ACRONYMS

Acronyms

APCD – Air Pollution Control Device
BACT –Best Available Control Technology
BART – Best Available Retrofit Technology
BOOS – Burners Out of Service
CAA – Clean Air Act
CAAA – Clean Air Act Amendments (of 1990)
CFBA – Circulating Fluidized-Bed Absorption
CFR – Code of Federal Regulations
DI – Dry Injection
DSI – Dry Sorbent Injection
EGU – Electricity Generating Unit
ESP – Electrostatic Precipitators
FBC – Fluidized Bed Combustion
FF – Fabric Filter (also known as baghouse)
FGD – Flue Gas Desulfurization (also known as SO_2 scrubber)
FGR – Flue Gas Recirculation
FOM – Fixed Operating and Maintenance Costs
FSI – Furnace Sorbent Injection
GR – Gas Reburn
HHV – Higher Heating Value
ICI – Industrial, Commercial, and Institutional (boilers)
LAER – Lowest Achievable Emission Rate
LNB – Low-NOx Burner
LSDI – Lime Slurry Duct Injection
LSFO – Limestone Forced Oxidation
LSC – Low-Sulfur Coal (also known as compliance coal)
MACT – Maximum Achievable Control Technology
MANE-VU – Mid-Atlantic-Northeast Visibility Union
MC – Mechanical Collector
NAAQS – National Ambient Air Quality Standard
NCG – Non-Condensable Gases
NESCAUM – Northeast States for Coordinated Air Use Management
NSPS – New Source Performance Standards
NSR – Normalized Stoichiometric Ratio
OFA – Overfire Air
PC – Pulverized Coal
PRB – Powder River Basin (coal)
RACT – Reasonably Available Control Technology
RPO – Regional Planning Organization
SCA – Specific Collection Area
SCR – Selective Catalytic Reduction

SD – Spray Dryer
SIP – State Implementation Plan
SNCR – Selective Non-Catalytic Reduction
TCR – Total Capital Requirement
TR – Transformer Rectifier
UBC – Unburned Carbon
US EIA – United States Energy Information Administration
US EPA – United States Environmental Protection Agency
ULNB – Ultra Low-NOx Burner
VOM – Variable Operating and Maintenance (costs)
WESP – Wet Electrostatic Precipitator
WFGD – Wet Flue Gas Desulfurization (also known as wet SO_2 scrubber)

Chemical Species
HCl – Hydrochloric Acid
HF – Hydrofluoric Acid
H_2SO_4 – Sulfuric Acid
NOx – Oxides of Nitrogen (NO_2 and NO)
NO – Nitric Oxide
NO_2 – Nitrogen Dioxide
NH_3 – Ammonia
$PM_{2.5}$ – Particulate Matter up to 2.5 μm diameter in size
PM_{10} – Particulate Matter up to 10 μm diameter in size
S – Sulfur
SO_2 – Sulfur Dioxide
SO_4 – Sulfate
VOC – Volatile Organic Compound

Units
Length
m – meter
μm – micrometer or micron (0.000001 m; 10^{-6} m)
km – kilometer (1000 m; 10^3 m)
Mm – Megameter (1,000,000 m; 10^6 m)

Flow Rate
acfm – actual cubic feet per minute

Volume
L – liter
m^3 – cubic meter

Mass
lb – pound
g – gram
μg – micrograms (0.000001 g; 10^{-6} g)

kg – kilograms (1000 g; 10^3 g)

Force
psi – pounds per square inch

Power
W – watt (Joules/sec)
kW – kilowatt (1000 W; 10^3 W)
MW – megawatt (1,000,000 W; 10^6 W)

Energy
Btu – British thermal unit (= 1055 Joules)
MMBtu – million Btu
MWhr – megawatt-hour
kWhr – kilowatt-hour

Concentration
$\mu g/m^3$ – micrograms per cubic meter

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NESCAUM is an association of the eight northeast state air pollution control programs and provides technical guidance and policy advice to its member states.

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EXECUTIVE SUMMARY

ES-1 Objectives

The main objective of this study is to evaluate the viability of technologies for controlling emissions of nitrogen oxides (NOx), sulfur dioxide (SO_2), and particulate matter (PM) from industrial, commercial, and institutional (ICI) boilers. These pollutants contribute to the formation of ozone, fine particles, and regional haze, and to ecosystem acidification. This source sector is coming under increased scrutiny by air quality regulators needing emission reductions to meet Clean Air Act requirements.

This study also includes a literature review of emission control costs and develops methods for estimating the costs and cost effectiveness of air pollution controls for ICI boilers. The study concludes that ICI boilers are a significant source of emissions, are relatively uncontrolled compared to electricity-generating units (EGUs), and offer the potential to achieve cost effective reductions for all three pollutants. The results of this technical and economic evaluation are intended as a resource in assessing regulatory and compliance strategies for ICI boilers.

Most of the technologies considered in this report have been successfully applied to the larger EGU boilers. This study investigates both the feasibility of down-scaling such control technologies for ICI boiler applications and of certain technologies that have not been applied to EGUs, but show promise for the ICI boilers.

ES-2 Report Organization

Chapter One provides an overview of the ICI boiler fleet in terms of boiler size, applications, fuel type and associated emissions. Chapters Two, Three, and Four discuss control technology options for NOx, SO_2 and PM, respectively. Each chapter provides: (1) descriptions of available control technologies; (2) a discussion of the applicability of these technologies to ICI boilers; (3) published cost estimates; and (4) an assessment of the impact of control technologies on overall facility efficiency. Chapter Five summarizes information about air pollution control equipment costs for ICI boilers calculated with the Coal Utility Environmental Cost (CUECost) model.

ES-3 Differences between ICI and EGU Boilers

ICI and EGU boilers differ in size, application, design, and emissions. Most commercial and institutional boilers are relatively small, with an average capacity of 17 MMBtu/hour. Industrial boilers can be as large as 1,000 MMBtu/hr or as small as 0.5 MMBtu/hr. By contrast, the average size of a coal-fired EGU boiler in the U.S. is greater than 2,000 MMBtu/hr.

All coal-fired EGUs in the United States are equipped with PM control devices and many have SO_2 and NOx emission controls. ICI boilers are significantly less likely to have air pollution control devices.

As part of this study, NESCAUM conducted a preliminary survey of the use of emission controls on ICI boilers in the Northeast. Survey results revealed that more than half of the units surveyed in the region had no controls; about one-third had PM controls, while very few units

had NOx controls. None of the surveyed units had SO_2 controls, although some have wet venturi scrubbers for PM control, which minimally reduce SO_2 emissions.

Technical, operational, economic and regulatory factors impose different opportunities and constraints on the applicability of air pollution control devices (APCDs) for EGU and ICI boilers. The following technical and operational characteristics must be evaluated in determining the potential applicability of emission controls for specific ICI boilers.

- Fuel type and quality – SO_2, PM, and NOx emissions from coal-fired boilers are typically higher than from those burning natural gas, oil, or wood waste. Some APCD technologies are not particularly sensitive to such variations. For example, an electrostatic precipitator (ESP) or a fabric filter (FF) can accommodate different PM concentrations, although the type and size of PM and gas temperatures will have an impact. Other controls that utilize reagents, such as SO_2 scrubbers and selective catalytic reduction or selective non-catalytic reduction (SCR/SNCR) technologies for NOx, are directly affected by fuel type and quality.
- Duty cycle – APCD controls must be capable of accommodating significant variation or cycling of boiler loads. These variations affect flue gas flow rates and temperatures, which in turn may require different control capability. For example, an SCR or SNCR system must operate within a temperature window that may or may not exist across the load range for a particular ICI boiler.
- Design differences – The presence of equipment such as economizers or air preheaters has a direct impact on flue gas temperatures. Temperature-sensitive technologies such as ESPs, SO_2 scrubbers, and SCR/SNCR that are widely used in EGUs may or may not be applicable to ICI boilers in certain cases.

ES-4 NOx Control Technologies

Emission control strategies for NOx can be divided into two basic categories: combustion modifications and post-combustion technologies. Control efficiency ranges and cost effectiveness ($/ton of NOx removed) for various technologies are provided in Table ES-1. Combustion modification technologies, which minimize the formation of NOx during the combustion process, include: combustion tuning; low-NOx burners and overfire air (LNBs and OFA); and gas, oil, or coal reburn.

LNBs have minimal effect on overall operating costs, but may introduce higher carbon monoxide and/or carbon levels in the fly ash, which reflect lower plant efficiency. In the case of gas reburn, operating costs are primarily a function of the fuel cost differential; for coal or oil reburn, fuel preparation costs (pulverization and atomization, respectively) represent the primary operating and maintenance costs. While gas reburn is easier to implement, the fuel differential costs are often prohibitive. The overall cost of low-NOx combustion technology installation depends on the firing system, and this is reflected in the lack of a clear relationship between capital cost and boiler capacity.

Post-combustion technologies reduce the amount of NOx exiting the stack that was formed during combustion. This group includes SNCR, SCR, and regenerative SCR (RSCR) technologies. Because the reaction occurs without the need for catalysts, SNCR systems have

lower capital costs, but achieve lower NOx reduction. SCR, on the other hand, is capital-intensive, but offers the opportunity for significantly greater NOx reductions because a dedicated reactor and a reaction-promoting catalyst ensure a highly controlled, efficient reaction. RSCR combines a regenerative thermal oxidizer with SCR technology, making it suitable for facilities with lower gas temperatures, such as those found in some ICI boilers. RSCRs can also reduce carbon monoxide emissions by half.

ES-5 SO_2 Control Technologies

SO_2 emission control technologies are post-combustion devices that utilize a process involving SO_2 reacting in the exhaust gas with a reagent (usually calcium- or sodium-based) and removal of the resulting product (a sulfate/sulfite) for disposal or commercial use. SO_2 control technologies are commonly referred to as flue gas desulfurization (FGD) and/or "scrubbers" and are usually characterized in terms of the process conditions (wet vs. dry), byproduct utilization (throwaway vs. saleable), and reagent utilization (once-through vs. regenerable). Wet scrubbers provide much greater levels of SO_2 control. Conventional dry processes include spray dryers (SDs) and dry sorbent injection (DSI). The capital costs of wet scrubbers are higher than those of dry scrubbers, although the cost effectiveness values (in dollars per ton of SO_2 removed) of wet and dry processes are similar. DSI technology has a significantly lower capital cost than wet or dry scrubbers and should therefore be more attractive for ICI boilers than conventional scrubbers.

In the eight-state NESCAUM region, residual oil is a common fuel for ICI boilers. Switching to a lower sulfur residual oil (for example, from 3 percent to 1 percent sulfur residual oil) can provide cost-effective SO_2 reductions. The cost of switching to lower sulfur distillate oil is much higher than switching to low sulfur residual oil, because the cost of distillate oil has been about twice that of residual oil in recent years. The cost effectiveness (in dollars per ton of SO_2 removed) from switching from residual fuel oil to distillate fuel oil is not as attractive and falls in the range of the cost effectiveness of installing a FGD scrubber.

ES-6 PM Control Technologies

Combustion processes emit both primary and secondary particulate matter. Primary emissions consist mostly of fly ash (e.g., non-combustible inorganic matter and unburned solid carbon). Secondary emissions are the result of condensable particles such as nitrates and sulfates that typically make up the smaller fraction of the particulate matter. PM control technologies include: fabric filters or "baghouses," wet and dry ESPs, venturi scrubbers, cyclones, and core separators. While PM controls are not currently widely used on ICI boilers, there are no technical reasons why PM controls cannot be applied to solid-fueled and oil-fired ICI boilers.

ES-7 Impact of Control Technologies on Operational Efficiency and Carbon Dioxide Emissions

Air pollution control technologies and strategies (e.g., fuel switching) can have varying impacts on the overall efficiency of the host plant. This impact can be either positive or negative depending on technology and fuel choices.

Carbon dioxide (CO_2) emissions are primarily a function of the carbon content of fuels. However, the application of conventional pollutant control technologies can affect CO_2 emissions. This impact can vary widely among technologies within the same pollutant (e.g.,

LNB vs. SCR for NOx), as well as across different pollutants (e.g., fabric filter for PM vs. scrubbers for SO_2).

Combustion modification technologies for NOx have essentially no impact on the CO_2 emissions of the host boilers – with the noted exception of reburn when displacing coal or oil with natural gas – because the technologies do not impose any significant parasitic energy consumption (auxiliary power) requirements. With respect to the post-combustion technologies, both SNCR and SCR impose some degree of energy demand on the host boiler. These impacts include pressure, compressor, vaporization, and steam losses, and can range from 1–2 kW/1000 actual cubic feet per minute (acfm) for SNCR and up to about 4 kW/1000 acfm for SCR.

The major components affecting energy consumption for SO_2 systems include electrical power associated with material preparation (e.g., grinding) and handling (pumps/blowers), flue gas pressure loss across the scrubber vessel, and steam requirements. The power consumption of the SO_2 control technologies is further affected by the SO_2 control efficiency of the technology itself. SO_2 controls have a range of potential parasitic losses, from duct injection representing about 1–2 kW/1000 acfm to wet FGD at as high as 8 kW/1000 acfm.

PM control technologies will result in some parasitic energy loss due to pressure loss, power consumption, and ash handling. Dry ESPs and fabric filters have the lowest associated parasitic power consumption (<2 kW/1000 acfm), while high-energy venturi scrubbers can be up to 10 kW/1000 acfm or higher.

ES-8 Cost Analysis

Cost is an important factor in evaluating the viability of air pollution control technologies. Information on capital and operating costs is more readily available for EGU than ICI boilers. Operating costs may be different for ICI boilers than utility boilers because of their size and the fact that they are typically located on smaller sites. Operating costs also include waste disposal and reagent use. ICI boiler sites typically have higher contingency, general facility, engineering, and maintenance costs, as a percentage of total capital cost, than those for utility boilers.

Cost estimates for ICI boilers with capacities ranging from 100 to 250 MMBtu/hr were generated by the CUECost model. This model, created by Raytheon Engineers for US EPA, was originally developed for large coal-fired EGUs and calculates capital and operating costs for certain pre-defined air pollution control devices for NOx, SO_2, and PM. The CUECost model produces approximate estimates (±30 percent accuracy) of installed capital and annualized operating costs. The CUECost model was adapted in this study for ICI boilers burning a variety of fuels by changing the fuel composition and heating value to simulate different fuels. This study represents the first attempt to utilize a comprehensive cost model specific to ICI boilers.

Chapter Two contains a detailed discussion of the literature values for NOx control costs for ICI boilers. The NOx control costs for ICI boilers computed with CUECost were largely consistent with values reported in the literature. In terms of NOx removal, reported values were in the range of $1,000 to $3,000 per ton for LNBs or SNCR, and $2,000 to $14,000 per ton for SCR. The SCR costs for coal-fired ICI boilers appear to be consistent with the literature, although the CUECost capital cost values for residual oil were higher than the literature values. The capital costs for SNCR calculated from the CUECost models were in good agreement with literature values, particularly their sensitivity to boiler capacity. The capital costs for LNBs

calculated from CUECost for coal-fired boilers were consistent with the literature values, although the costs for residual oil-fired boilers were higher in CUECost than the literature values.

Chapter Three contains a detailed discussion of the literature values for SO_2 control costs for ICI boilers. In terms of the cost per ton of SO_2 removed, reported values were in the range of $1,600 to $5,000 for spray dryers (SDs) and $1,900 to $5,200, for wet FGDs. The SO_2 capital costs computed with CUECost for SDs were in the range of the literature values at 250 MMBtu/hr. However, the capital costs computed by CUECost for wet FGDs were high compared to values reported in the literature.

Chapter Four contains a detailed discussion of the literature values for PM control costs. Literature values for capital costs for PM control were evaluated from EPA reports on PM controls applied to industrial boilers. The cost effectiveness of ESPs was in the range of $50 to $500 per ton of PM for coal, and up to $20,000 per ton of PM for oil. The cost effectiveness of baghouses was in the range of $50 to $1,000 per ton of PM for coal and up to $15,000 per ton of PM for oil.

The dry-ESP control costs computed with CUECost were consistent with the literature values, although the CUECost predicted slightly higher values than reported by EPA for dry, wire-plate ESPs. The baghouse/fabric filter costs computed with CUECost were higher than the literature values for pulse-jet fabric filters.

This adaptation of CUECost model from EGUs to ICI boilers was intended to investigate the feasibility of estimating costs of controlling emissions of NOx, SO_2, and PM from ICI boilers. Further detailed work would be needed to validate this approach, but initial results included in this report are promising.

ES-9 Conclusion

ICI boilers are a significant source of NOx, SO_2, and PM emissions, which contribute to the formation of ozone, fine particles, and regional haze, and to ecosystem acidification. These boilers are relatively uncontrolled compared to EGUs and offer the potential to achieve cost-effective reductions for all three pollutants. A host of proven emission control technologies for EGUs can be scaled-down and deployed in industrial, commercial, and institutional settings to cost-effectively reduce emissions of concern. Other technologies that have not been applied to EGUs show promise for ICI boiler applications. Careful analysis will be needed to match the appropriate emission control technology for specific applications given: boiler size, fuel type/quality, duty-cycle, and design characteristics. Further, regulators will need to determine the level of emission reductions needed from this sector in order to inform the appropriate choice of controls.

Table ES-1. ICI Boiler Control Technologies

Pollutant	Technology	Control Efficiency	Cost Effectiveness $ per ton
NOx			
Combustion Modifications	Tuning	5-15%	current data not available
	LNB	25-55%	$750-$7,500
	Reburn	35-60%	current data not available
Post-Combustion	SNCR	30-70%	$1,300-$3,700
	SCR	70-90%	$2,200-$14,400
	RSCR	60-75%	$4,500
SO_2	Wet Scrubbers	95+%	$1,900-$5,200
	Spray Dryers	90-95%	$1,600-$5,200
	Dry Sorbent Injection	40-90%	current data not available
PM			
	Fabric Filters/Baghouses	99+%	$400-$1,000 – coal $6,900-$16,500- oil
	Wet/Dry ESPs	99+%	$160-$2,600 – coal $2,300 to $43,000 - oil
	Venturi Scrubbers	50-90%	current data not available
	Cyclones	70-90%	current data not available
	Core Separators	60-75%	current data not available

1 INTRODUCTION

1.1 Objectives

The main objective of this study is to evaluate various available control technologies and their cost effectiveness in reducing emissions of three pollutants: oxides of nitrogen (NOx), sulfur dioxide (SO_2), and primary fine particulate matter ($PM_{2.5}$) from industrial, commercial, and institutional (ICI) boilers. The study results should provide a strong technical and economic basis for developing cost-effective regulations and strategies to reduce emissions of these three major pollutants from ICI boilers.

1.2 Regulatory Drivers

Federal, state and local governments regulate all major criteria air pollutants under the authority of the Clean Air Act (CAA). The CAA mandates control of pollutants such as NOx, SO_2, and $PM_{2.5}$ to attain and maintain National Ambient Air Quality Standards (NAAQSs) for ozone and $PM_{2.5}$, reduce acidic deposition, and improve visibility under regional haze regulations. Emission standards for specific source categories, including ICI boilers, are also set by federal, state, and local governments to attain and maintain a NAAQS. Examples of these emission standards include New Source Performance Standards (NSPS), Best Available Control Technology (BACT), Lowest Achievable Emission Rate (LAER), Reasonably Available Control Technology (RACT), and Best Available Retrofit Technology (BART).

States must formulate State Implementation Plans (SIPs) that provide a framework for limiting air emissions from major sources as part of a strategy for demonstrating attainment and maintenance of NAAQS. Some individual SIPs (if allowed by the state law) may set more stringent limits on emissions of NOx, SO_2, and $PM_{2.5}$ than required by the federal rules. However, states cannot set less stringent limits than required by federal rules and regulations. Generally, federal, state, and local permitting authorities rely upon available information on the latest advanced technologies for emission control when setting emission limits. Where applicable, permitting authorities require BACT and RACT in order to reduce air emissions from stationary sources. In areas that have not achieved a NAAQS (i.e., non-attainment areas), the CAA requires air pollution limits established by LAER for new major stationary sources and major modifications to existing stationary sources. BACT and RACT analyses consider the cost of controls. LAER control technologies, applicable to new major sources located in non-attainment areas, must be installed, operated and maintained without consideration of costs.

1.3 Characterization of Combustion Sources

1.3.1 Description of Combustion Sources

Boilers utilize the combustion of fuel to produce steam. The hot steam is then employed for space and water heating purposes or for power generation via steam-powered turbines.

Boiler size is typically represented in four ways: fuel input in units of MMBtu/hr, output of steam in lb steam/hr at a specified temperature and pressure, boiler horsepower (1 boiler hp = 33,475 MMBtu/hr), or electrical output in MWhr or MW (if electricity is generated).

The three main types of boilers are described below:

- *Firetube boilers*. Hot gases produced by the combustion of fuel are used to heat water. The hot gases are contained within metal tubes that run through a water bath. Heat transfer through thermal conduction heats the water bath and produces steam. Typically, firetube boilers are small, with capacity below 100 MMBtu/hr.
- *Watertube boilers*. Hot gases produced by fuel combustion heat the metal tubes containing water. Typically, there are several tubes configured as a "wall." Watertube boilers vary in size from less than 10 MMBtu/hr to10,000 MMBtu/hr.
- *Fuel-firing*. Fuel is fed into a furnace and the high gas temperatures generated are used to heat water. Fuel-firing boilers include stoker, cyclone, pulverized coal, and fluidized beds. Stokers burn solid fuel and generate heat either as flame or as hot gas. Pulverized coal (PC) enters the burner as fine particles. The combustion in the furnace produces hot gases. The ash (the unburned fraction) exits in molten or solid form. Fluidized beds utilize an inert material to "suspend" the fuel. The suspension allows for better mixing of the fuel and subsequently better combustion and heat transfer to tubes.

Boilers are also classified by the fuel they use – chiefly coal, oil, natural gas, wood, and waste byproducts.

1.3.2 Emissions by Size, Fuel, and Industry Sector

In 2005, Energy & Environmental Analysis, Inc. [EEA, 2005] estimated that there were 162,805 industrial and commercial boilers in the U.S., which had a total fuel input capacity of 2.7 million MMBtu/hr as summarized in Figure 1-1 and Table 1-1. This estimate included 43,015 industrial boilers with a total capacity of 1.6 million MMBtu/hr and 119,790 commercial boilers with a total capacity of 1.1 million MMBtu/hr. In addition, EEA estimated that there were approximately 16,000 industrial boilers in the non-manufacturing sector with a total capacity of 260,000 MMBtu/hr, but details on size distribution of these boilers were not provided because these units were not well characterized.

The EEA report divided boilers into two major categories (industrial and commercial) instead of the more common characterization as industrial, commercial, and institutional boilers. One segment of the ICI boiler population, identified as non-manufacturing industrial boilers, is not included in the EEA analyses due to a lack of sufficient data. The non-manufacturing segment accounted for only 11 percent of energy consumption in the industrial boiler population. The manufacturing and non-manufacturing segment of the population appear (from EEA's description) to correspond to what would be called industrial boilers. The commercial segment of the population includes what are designated in this report as commercial and institutional boilers. For example, there are several large boilers located at major institutions such as universities (e.g., Notre Dame, Cornell, etc.) and also several large boilers located at major hospitals (e.g., Massachusetts General Hospital) that belong in the institutional category instead

of the commercial sector. Thus, EEA's analysis appears to apply to most of the ICI boiler population, representing 89 percent of energy use by ICI boilers.

Industrial boilers were generally larger than commercial units. Sixty percent of the boilers in the manufacturing sector were greater than 100 MMBtu/hr in capacity, whereas 60 percent of the boilers in the commercial sector were in the range of 10 to 100 MMBtu/hr. The average capacity of the commercial boilers was 10 MMBtu/hr, with most less than 10 MMBtu/hr; the capacity of the average industrial boiler was 36 MMBtu/hr. Non-manufacturing boilers fell in between, at an average capacity of 16 MMBtu/hr. For industrial boilers, the average capacity factor was 47 percent (capacity factor is defined as the ratio of actual heat input in MMBtu to the maximum heat input based on nameplate capacity of the unit, calculated for a period of one year).

Table 1-1. Capacity of industrial boilers [EEA, 2005]

Unit Capacity	Manufacturing Boilers	Non-Mfg Boilers*	Commercial Boilers	Total
<10 MMBtu/hr	102,306	---	301,202	403,508
10-50 MMBtu/hr	277,810	---	463,685	741,495
50-100 MMBtu/hr	243,128	---	208,980	452,108
100-250 MMBtu/hr	327,327	---	140,110	467,437
>250 MMBtu/hr	616,209	---	33,639	649,848
Total Capacity, MMBtu/hr	1,566,780	260,000	1,147,617	2,714,397
Total Capacity >10 MMBtu/hr	1,464,474	---	846,415	2,310,889**
Total number of units	43,015	16,000	119,790	162,805
Average Capacity, MMBtu/hr	36	16	10	17

*No details provided on range of capacities

**Total does not include non-manufacturing boilers

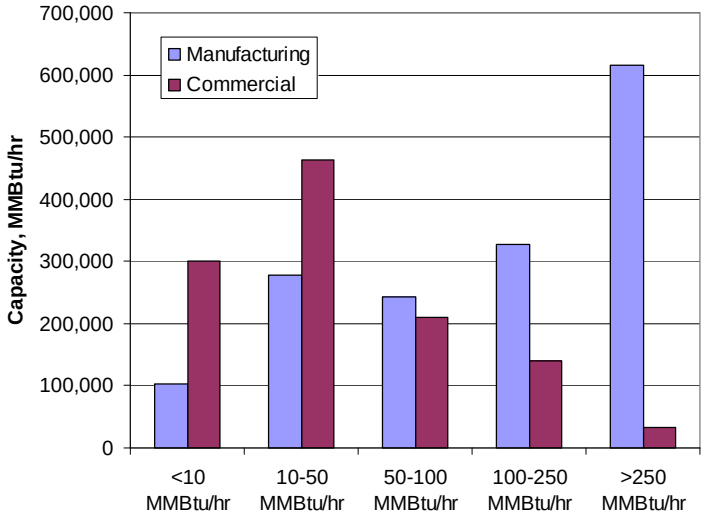


Figure 1-1. Total capacity of industrial boilers as a function of size [EEA, 2005]

Five major steam-intensive industries accounted for more than 70 percent of the boiler units and more than 80 percent of the boiler capacity of the manufacturing segment of industrial boilers: food, paper, chemicals, petroleum refining, and primary metals. The non-manufacturing segment of the industrial sector included agriculture, mining and construction. The largest categories in the commercial sector, by capacity, were schools, hospitals, lodgings, and office buildings.

Industrial boilers in the manufacturing sector are used to generate process steam and electricity. The fuels used in manufacturing boilers are related to the size of the boilers and, in some cases, the byproducts generated in the particular manufacturing process.

In the food production subsector, the average boiler capacity was 20 MMBtu/hr. The relatively small average capacity was reflected in the higher percentage (58 percent) of natural gas-fired boilers in the food industry than in any other major subsector, since very small boilers tend to burn natural gas.

The paper industry included some of the largest industrial boilers, with an average boiler size of 109 MMBtu/hr. The paper industry represented more than half (230,000 MMBtu/hr) of the total capacity of the manufacturing sector. More than 60 percent of the fuel used in paper industry boilers was wood (bark, wood chips, etc.) or black liquor, a waste product from the chemical pulping process.

The chemical industry employed both large and small boilers, with about seven percent of the units with capacities smaller than 10 MMBtu/hr, and a significant number (about 350 or 37 percent of total capacity) larger than 250 MMBtu/hr. The primary fuels for chemical industry boilers were natural gas (43 percent), process off-gas (39 percent), and coke (15 percent).

The refining industry had an average boiler size of 143 MMBtu/hr, the largest of any of the major industries, with over 200 boilers with capacities above 250 MMBtu/hr. By-product fuels (refinery gas or carbon monoxide) were the most common fuel source for boilers (58 percent), followed by natural gas (29 percent) and residual oil (11 percent).

About half of the total boiler capacity in the primary metals industry was from boilers larger than 100 MMBtu/hr. By-product fuels, like coke oven gas and blast furnace gas, provided the largest share (63 percent) of boiler fuel in the primary metals industry.

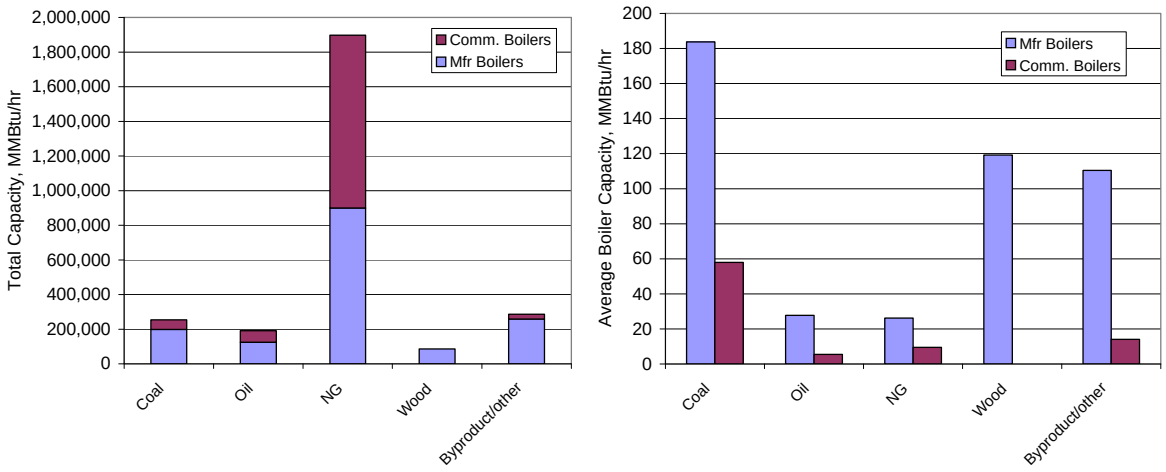
The remaining industries accounted for about 29 percent of manufacturing boilers (12,000 units) or about 18 percent of industrial boiler capacity. The average capacity for the rest of the manufacturing subsector was 23 MMBtu/hr. Approximately 100 boilers at other manufacturing facilities had capacities larger than 250 MMBtu/hr.

Unlike industrial boilers, which serve production processes, commercial boilers provide space heating and hot water for buildings. Natural gas fired the vast majority of commercial boilers, including 85 percent of commercial boiler units and 87 percent of the total commercial boiler capacity. About 10 percent of the commercial boilers were fired by oil. Coal was fired at about one percent of the commercial boilers, but represented five percent of the capacity, reflecting the larger size of commercial coal-fired boilers.

Figure 1-2 summarizes the total US boiler capacity in the manufacturing and commercial sectors as a function of fuel fired (left side of figure) and shows the average capacity per boiler (right side of figure) by fuel type. Coal-fired boilers were the largest in size on average. As discussed above, natural gas accounted for 70 percent of the total industrial boiler capacity in the

EEA survey. Coal and byproduct fuels accounted for about 10 percent each, with lesser capacity in oil- and wood-fired boilers.

In the manufacturing sector, the average coal-fired boiler capacity was about 180 MMBtu/hr, but the average capacity in both sectors combined was about 125 MMBtu/hr. Wood- and byproduct-fired boilers in the manufacturing sector were also large on average (120 and 110 MMBtu/hr, respectively). On the other hand, oil- and natural gas-fired boilers were small, on the order of 20 MMBtu/hr in the manufacturing sector and less than 10 MMBtu/hr in the commercial sector.



(a) Total capacity by fuel and sector

(b) Average capacity by fuel and sector

Figure 1-2. Total and average boiler capacity of U.S. industrial boilers as a function of fuel fired [EAA, 2005]

From EEA's 2005 study, the following general conclusions about boiler size for the entire U.S. ICI boiler population can be drawn:

- natural gas is the fuel fired at most ICI boilers;
- natural gas- and oil-fired boilers tend to be small, less than 20 MMBtu/hr in capacity;
- boilers fired with coal, wood, or process byproducts are larger in size, greater than 100 MMBtu/hr on average;
- although natural gas fired most of the ICI boilers in the U.S., coal, oil, and wood contribute substantially more to the emissions of SO_2 and PM; and
- all fuels are sources of NOx emissions.

One needs to be careful drawing conclusions for the eight-state NESCAUM region based on the national data in the EEA 2005 study because there are large region-to-region and state-to-state differences in boiler populations. For example, fuel oil is an important fuel in the Northeast, especially in rural areas where natural gas may not be available, while natural gas is predominant in other areas of the country.

A preliminary assessment of emissions from ICI boilers by pollutant in the U.S. and in the eight-state NESCAUM region was carried out using data from the AirData database via the EPA website (www.epa.gov/air/data). In this database, stationary sources, such as electric generating plants and factories, are identified individually by name and location. Figure 1-3 compares the annual emission of NOx, SO_2, and $PM_{2.5}$ in the U.S. with the eight-state NESCAUM region for 2002. Emissions in the NESCAUM region are about 5 percent of the US total emissions.

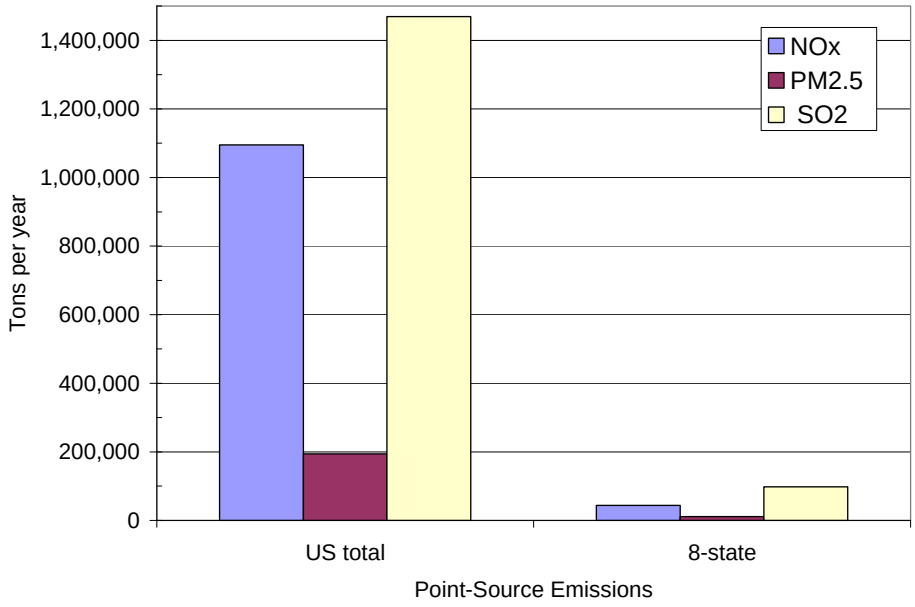


Figure 1-3 Total annual emissions of NOx, SO_2, and $PM_{2.5}$ from ICI boilers in the U.S. and in the eight-state region from EPA AirData database

Another set of data from the eight-state region was extracted from the MANEVU 2002 non-road inventory (www.manevu.org). In this data set, oil-fired boilers were divided into distillate oil and residual oil-fired boilers (Figure 1-4).

NOx emissions in the eight-state NESCAUM region are mostly from oil- and gas-fired boilers. Because these are generally small boilers, combustion controls are good candidates for NOx control. For larger, coal- or wood-fired boilers, SNCR or SCR might also be applicable.

PM emissions are relatively low from coal-fired sources in the eight-state region, which suggests that most of the coal-fired sources already have particulate control devices. Oil- and wood-fired units have higher PM emissions, and PM emissions attributed to natural gas are quite small.

As might be expected, most of the SO_2 emissions from oil-fired boilers come from residual oil-fired boilers because of residual oil's higher sulfur content.

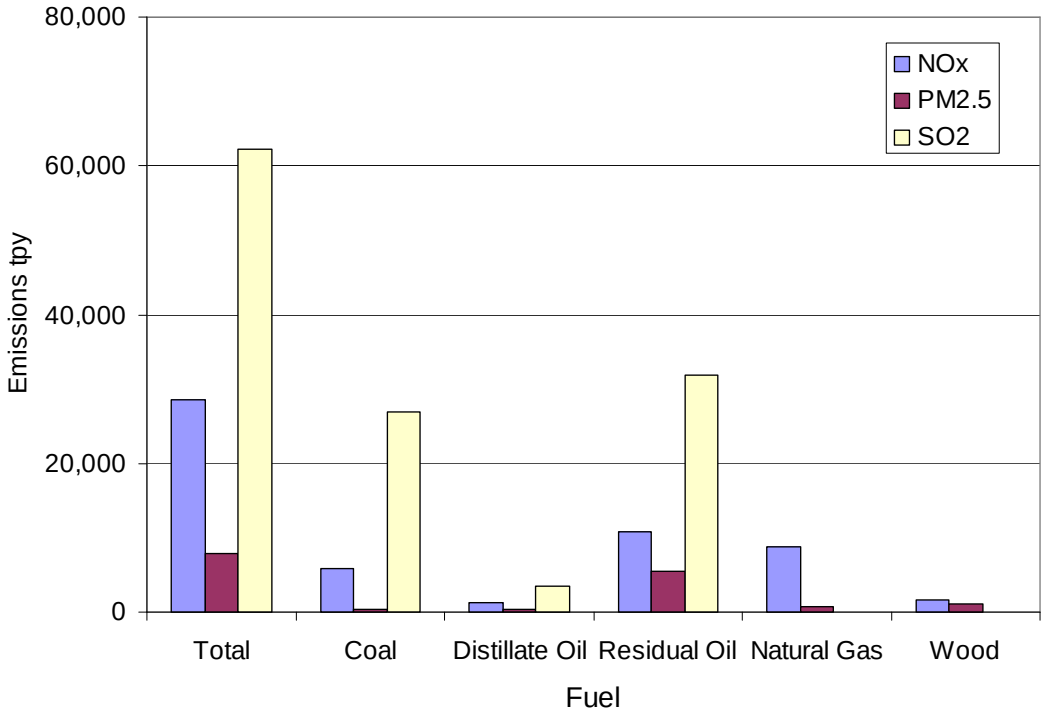


Figure 1-4. Emissions of NOx, SO_2, and $PM_{2.5}$ from ICI boilers in the NESCAUM region from MANEVU database as a function of fuel fired

1.3.3 Differences between EGU and ICI boilers

EGU boilers produce steam in order to generate power. While ICI boilers do in some cases generate steam for electricity production, ICI boilers differ from EGUs in size, steam application, design, and emissions. Most commercial and institutional boilers are small, with an average capacity of 17 MMBtu/hour (Table 1-1). Industrial boilers can be as large as 1,000 MMBtu/hr or as small as 0.5 MMBtu/hr. The average size of a coal-fired EGU boiler in the U.S. is over 200 MW or over 2,000 MMBtu/hr.

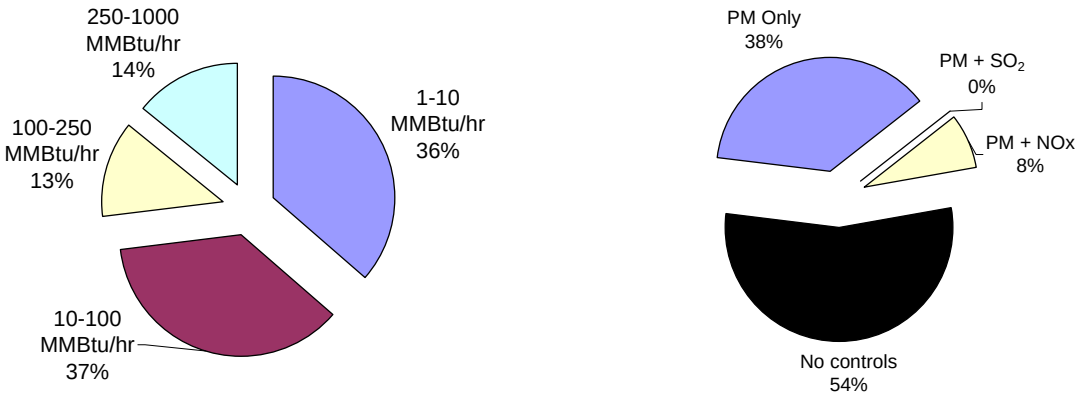
All coal-fired EGUs in the United States use control devices to reduce PM emissions. Additionally, many of the EGU boilers are required to use controls for SO_2 and NOx emissions, depending on site-specific factors such as the properties of the fuel burned, when the power plant was built, and the area where the power plant is located.

According to 1999 EPA Information Collection Request (ICR) responses from coal-fired EGUs, 77.4 percent of EGUs had PM post-combustion control only, 18.6 percent had both PM and SO_2 controls, 2.5 percent had PM and NOx controls, and 1.3 percent had all three post-combustion control devices [Kilgroe *et al.*, 2001]. Information from 2004 indicated that the fractions of total capacity of large coal-fired EGUs that have flue gas desulfurization (FGD) to control SO_2 and selective catalytic reduction (SCR) to reduce NOx controls were 38 percent and 37 percent, respectively [NESCAUM, 2005]. Since the 1999 ICR survey, additional NOx and SO_2 controls have been added at a rapid pace to coal-fired EGUs. It is presently not clear how

the implementation of NOx and SO_2 control technologies for EGUs would evolve as a consequence of the recent vacatur of Clean Air Interstate Rule (CAIR) by the U.S. D.C. Circuit.

In contrast to EGUs, ICI boilers are substantially less likely to have air pollution control devices. A study of industrial boilers and process heaters [USEPA, 2004] that looked at 22,117 industrial boilers and process heaters, which burned natural gas, distillate oil, residual oil, and coal, found that 88 percent had no air pollution control equipment.

A preliminary survey was undertaken as part of this study to evaluate the extent to which various emission controls were currently being applied to ICI boilers in the Northeast. These data were acquired from State Title V permits for solid-fueled (coal and wood) boilers as well as additional information from state personnel. The survey collected data in four states: Massachusetts, Vermont, New Hampshire, and New York. The data set was composed of 64 boilers – 47 wood-fired and 17 coal-fired. *Figure 1-5* illustrates the distribution of boiler capacity (by size) and the air pollution control devices (APCDs) in this data set. The full data set is summarized in Appendix A. As can be seen in *Figure 1-5(b)*, more than half of the units had no controls, about one-third had controls only for PM, and very few units had controls for NOx. There were no units with SO_2 controls, although some of the PM controls were wet venturi scrubbers, which might have a limited impact on SO_2 emissions.



(a) Distribution of capacity

(b) Distribution of APCDs

Figure 1-5. Solid-fuel boiler information from four northeast states, based on Title V permit information

There are several factors that directly or indirectly affect the reasons for the discrepancy in APCD deployment between EGU and ICI boilers. Technical and operational as well as business, economic, and regulatory factors impose different constraints and provide different opportunities for the applicability of APCDs for these two categories of boilers. The following discussion summarizes some of the important technical and operational issues.

Large, base-loaded EGUs operate mainly near maximum capacity or steam production. Industrial boilers typically do not run at maximum capacity, although this varies from one industry to another [EEA, 2005]. EGUs produce steam for electricity generation, while ICIs may produce steam for a variety of applications. The type of manufacturing is often more important

in determining boiler operation, or duty cycle (load vs. time) than manufacturing demand in general.

ICI boilers generate steam for processing operations for paper, chemical, refinery, and primary metals industries. Commercial boilers produce steam for a variety of processes, while institutional boilers are normally used to produce steam and hot water for space heating in office buildings, hotels, apartment buildings, hospitals, universities, and similar facilities.

Another difference between EGU and ICI boilers is fuel diversity. EGU boilers are mostly single-fuel (coal, No. 6 oil, natural gas), while ICI boilers tend to be designed for and use a more diverse mix of fuels (e.g., fuel by-products, waste, wood) in addition to the three conventional fuels above.

These differences in operational and fuel usage not only affect a boiler's duty cycle, but its design, which is equally important from the perspective of APCD applicability. Examples that directly affect APCD choice and applicability include equipment such as economizers or air preheaters, which affect the temperature of the flue gas at the stack. The differentiation in fuel usage also leads to different design parameters for emissions controls. For example, the iron and steel industry generates blast furnace gas or coke-oven gas, which is used in boilers, resulting in sulfur emissions. Pulp and paper boilers may use wood waste as a fuel, resulting in high PM emissions. Units with short duty cycles may utilize oil or natural gas as a fuel. The use of a wide variety of fuels is an important characteristic of the ICI boiler category.

These factors relate directly to APCD equipment choices and applicability. The following examples should help explain some of these impacts.

- Fuel quality – different fuels have different emission characteristics. SO_2, PM, and NOx emissions from coal fired boilers are different from those burning natural gas, oil, or wood waste. Some APCD technologies are not very sensitive to fuel quality variations (e.g., an electrostatic precipitator (ESP) may accommodate different levels of PM concentration, although the type and size of particles and gas temperatures will have an impact). However, others can be directly affected by changes in fuel quality and the resulting changes in pollutant concentrations in the flue gas to be treated (e.g., SO_2 and NOx controls that utilize reagents such as scrubbers for SO_2 and SCR/SNCR for NOx).
- Duty cycle – significant variation or cycling of boiler load requires APCD controls capable of accommodating such variations. These variations affect flue gas flow rates and temperatures, which in turn may require different control capability. For example, an SCR or SNCR system must operate within a temperature window that may or may not exist across the load range for a particular ICI boiler.
- Design differences – the use of equipment such as economizers or air preheaters has direct impact on the resulting flue gas temperature. Temperature-sensitive technologies such as ESPs, SO_2 scrubbers (wet and dry), and SCR /SNCR that are widely used in EGUs may or may not be applicable for some ICI boilers in such cases.

1.3.4 Control Technology Overview

A variety of emission control technologies are employed to reduce emissions of NOx, SO_2, and primary PM emissions. Technical details of control technologies for NOx, SO_2, and PM are discussed in Chapters Two, Three, and Four, respectively. Pollutant emission controls are generally divided into three major types given in the following list.

- *Pre-combustion Controls*. Control measures in which fuel substitutions are made or fuel pre-processing is performed to reduce pollutant formation in the combustion unit.
- *Combustion Controls*. Control measures in which operating and equipment modifications are made to reduce the amount of pollutants formed during the combustion process; or in which a material is introduced into the combustion unit along with the fuel to capture the pollutants formed before the combustion gases exit the unit.
- *Post-combustion Controls*: Control measures in which one or more air pollution control devices are used at a point downstream of the furnace combustion zone to remove the pollutants from the post-combustion gases.

Data on costs of pollution control equipment taken from the literature are reviewed in the individual technology chapters. In Chapter Five, an existing model for the estimation of air pollution control equipment costs for coal-fired EGUs (CUECost) is applied to ICI boilers burning different fuels (coal, oil, wood) with appropriate caveats and assumptions to provide reasonable and approximate control costs for ICI boilers.

1.4 Chapter 1 References

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2 NOx CONTROL TECHNOLOGIES

2.1 Introduction

This brief introduction applies to chapters Two, Three, and Four, which discuss control technology options for ICI boilers for NOx, SO_2, and PM, respectively. However, these chapters are not intended to provide detailed descriptions of the many available technologies for each pollutant. Significant literature is available for that purpose; in the context of this report, these chapters are intended to provide the reader with a general understanding of concepts, performance, applicability, and costs of the main technologies available. Further, in recognition of the concern with climate change, a brief discussion of energy consumption (parasitic power) associated with major technologies is included.

Specifically with respect to the deployment and applicability of air pollution controls, comparisons between ICI boilers and EGUs are relevant because of the more widespread application of pollution control equipment in the EGU sector. This was discussed in some detail in Chapter One. In addition, a few considerations specific to certain technologies and strategies are discussed, as appropriate.

2.1.1 ICI versus EGU Boilers

In general, the greater proliferation of air pollution control technologies in the EGU sector, as opposed to the industrial sector, seems to be driven by three dominant, differentiating factors.

- Size difference and associated emissions between the two: Because EGUs are much larger than ICI boilers, they have been targeted for environmental regulatory controls more heavily over the years.
- Technology costs: While not universally true, ICI boilers often have constraints due to their smaller sizes, diversity of plant layouts, and urban settings, all of which can have a negative impact on the costs of applying some of the control technologies. Conversely, and equally important, opportunities for lower-cost applications to ICI boilers do exist as a result of the smaller sizes, such as in the ability to have systems pre-fabricated and ready to erect onsite, as opposed to on-site construction requirements often needed with larger systems for EGUs.
- Cost recovery: The two sectors are significantly different from a fundamental business view, with EGUs being regulated entities, as opposed to openly competitive markets that exist within the ICI boiler population. This is important in that it affects how business decisions are made in the two sectors, how capital equipment purchases are funded, and also how ICI plants are designed and operated.

2.1.2 Control Technologies' Impact on Efficiency and CO_2 Emissions

Air pollution control technologies and strategies can have varying impacts on the overall efficiency of the host plant. This impact can be either positive or negative and it is a function of the type of technology, as well as fuel choices.

An extreme example of this is the control of SO_2 from a coal-fired unit by two significantly different approaches: in one case, the use of an energy–intensive FGD "scrubber" penalizes the efficiency of such unit by up to 2 percent, resulting in a corresponding increase in CO_2 emissions; a very different and contrasting case, in which the unit chooses to reduce its SO_2 generation by switching from coal to natural gas, yields a corresponding and substantial decrease in its CO_2 emissions. Similarly, an efficient Low-NOx Burner (LNB) may replace an older burner and increase unit efficiency, while reducing NOx emissions, whereas a SNCR or SCR also reduces NOx, but will have some inherent parasitic power requirement that will have a negative impact on overall efficiency (and emissions of CO_2).

These chapters primarily address control technology options, as opposed to fuel switching strategies, except for SO_2. Switching from high-sulfur oil to low-sulfur oil is also discussed in Chapter 3. CO_2 impacts are well established as a function of the carbon content of fuels. The same applies in the case of renewable, carbon-based fuels (biomass). However, with control technologies, the impacts can vary widely among technologies for the same pollutant (e.g., LNB vs. SCR for NOx), as well as across different pollutants (e.g., fabric filter for PM vs. wet and dry scrubbers for SO_2).

In general, efficiency impacts from application of air pollution control technologies can be divided into two major general areas:

- Direct impact (positive or negative) on the combustion process itself (e.g., changes in concentrations of O_2 or CO and in the amount of unburned carbon (UBC) in ash)
- Parasitic power associated with the particular technology or its components (e.g., increased gas pressure loss, power requirements for pumps/fans)

This parasitic power is given here in terms of electric power (kW) per flue gas flow rate (acfm) or kW/1000 acfm. These units are appropriate for several reasons:

- Most ICI boilers do not produce electricity, hence, size is more universally characterized by a parameter other than electrical generation (e.g., flow rate);
- Most control technology suppliers rank their equipment size in terms of gas flow rate as this is the dominant parameter for gas handling equipment sizing;
- If the objective is to "correlate" this parasitic power loss to an equivalent CO_2 impact, it can be done simply by knowing the size (acfm) of the technology application and the CO_2 emission profile of the equivalent kW generation (or savings) to offset the parasitic power loss.

2.2 Discussion of NOx Control Technologies

2.2.1 NOx Formation

The formation of NOx is a byproduct of the combustion of fossil fuels. Nitrogen contained in fuels such as coal and oil, as well as the harmless nitrogen in the air, will react with oxygen during combustion to form NOx. The degree to which this formation evolves depends on many factors including both the combustion process itself and the properties of the particular fuel being burned. This is why similar boilers firing different fuels or similar fuels burned in different boilers can yield different NOx emissions.

2.2.2 NOx Reduction

As a result of complex interactions in the formation of NOx, a variety of approaches to minimize or reduce its emissions into the atmosphere have been and continue to be developed. A relatively simple way of understanding the many technologies available for NOx emission control is to divide them into two major categories: (1) those that minimize the formation of NOx itself during the combustion process (e.g., smaller quantities of NOx are formed); and (2) those that reduce the amount of NOx after it is formed during combustion, but prior to exiting the stack into the atmosphere. It is common to refer to the first approach under the "umbrella" of combustion modifications whereas technologies in the second category are termed post-combustion controls. Within each of these two categories, several technologies and variations of the same technology exist. Finally, combinations of some of these technologies are not only possible, but also often desirable as they may produce more effective NOx control than the application of a stand-alone technology.

2.2.3 Other Benefits of NOx Control Technologies

Some NOx control technologies have shown the potential to promote the capture of mercury (Hg) from the flue gas. Examples include combustion modification technologies (e.g., Low-NOx Burners and Overfire Air – though potentially with higher levels of unburned carbon) and post-combustion technologies (SCR – through the oxidation of mercury, making it more soluble and amenable to capture in a downstream process such as a scrubber for SO_2). This suggests that strategic and economic analyses for NOx controls need to also consider the potential impacts on mercury removal.

2.3 Summary of NOx Control Technologies

2.3.1 Combustion Modifications

Combustion modifications can vary from simple "tuning" or optimization efforts to the deployment of dedicated technologies such as LNBs, Overfire Air (OFA) or reburn (most often done with natural gas and called Gas Reburn - GR).

Boiler Tuning or Optimization

Combustion optimization efforts can lead to reductions in NOx emissions of 5 to 15 percent or even higher in cases where a unit was originally badly "de-tuned." It is important to remember that optimization results are truly a function of the "pre-optimization" condition of the power plant or unit (just as the improvement in an automobile from a tune-up depends on how badly it was running prior to it), and as such have limited opportunity for substantial emission reductions.

Development of "intelligent controls" – software-based systems that "learn" to operate a unit and then maintain its performance during normal operation, can also go a long way towards keeping plants well tuned, as they gain acceptance and become common features in combustion control systems.

2.3.2 Low-NOx Burners and Overfire Air

LNBs and OFA represent practical approaches to minimizing the formation of NOx during combustion. Simply, this is accomplished by controlling the quantities and the way in which fuel and air are introduced and mixed in the boiler (usually referred to as "fuel or air staging").



Figure 2-1. Low-NOx burner [TODD Dynaswirl-LN™]

Figure 2-1 shows a gas/oil Low-NOx burner. These technologies are prevalent in the electric power industry as well as in ICI boilers at present and increasingly used by ICIs, even at small sizes (less than 10 MMBtu/hr). Competing manufacturers have proprietary designs, geared towards application for different fuels and boiler types, as well as reflecting their own design philosophies. LNBs and OFA, which can be used separately or as a system, are capable of NOx reductions of 30 to 65 percent from uncontrolled baseline levels. Again, the type of boiler and the type of fuel will influence the actual emission reduction achieved.

Particularly for gas-fired applications, as in the majority of ICI boilers, advanced Low-NOx Burners, often referred to as ultra Low-NOx Burners (ULNBs), are commercially offered by several companies. Ultra Low-NOx Burners are capable of achieving NOx emission levels on the order of single digits in ppm. As with all technologies, "pushing the envelope" on emission levels requires increasingly more careful suitability analyses as well as a good understanding of operational constraints. Conversely, the advent of these very low-emission burners (less than 10 ppm NOx), allows units to achieve very low emission rates at costs well below post-combustion alternatives like SCR.

All combustion modification approaches face a common challenge of striking a balance between NOx reduction and decrease in fuel efficiency. The concern is exemplified by typically higher CO and/or carbon levels in the fly ash, which reflect lower efficiency and also the contamination of the fly ash itself, possibly making it unsuitable for reutilization such as in concrete manufacturing. This is a bigger concern for large EGUs than for ICI boilers due to the much larger quantities of ash produced and the associated costs of disposal.

LNBs/OFA have little or no impact on operating costs (other than by the potential for the above-mentioned efficiency loss). Low-NOx Burners are applicable to most ICI boiler types, excluding stoker types and Fluidized Bed Combustion units (FBCs).

2.3.3 Reburn

Reburn, while generically included in the "Combustion Modification" category, is different from the other technologies in this group (LNBs/OFA) in that it "destroys" (or chemically reduces) NOx shortly after it is formed rather than minimizing its formation as discussed previously. From a practical standpoint, this is accomplished by introducing the reburn fuel (theoretically any fossil fuel can be used, however, natural gas is the most common) into the boiler above the main burner region. A portion of the heat input from the primary fuel is replaced by the reburn fuel. Subsequently, this "fuel-rich" environment reacts with and destroys the NOx formed in the main burners. This technology has been implemented in the U.S. and overseas, and while not as popular as LNB/OFA, it is commercial at this time. Owing to stricter compatibility criteria, reburn is not as universal as LNB/OFA in its applicability to the overall boiler population. *Figure 2-2* shows a typical reburn system applied to a stoker boiler.



Figure 2-2. Gas reburn applied to a stoker boiler [www.gastechnology.org]

Specific criteria such as boiler size, availability of natural gas, type and quality of the main fuel, are all important in determining the suitability of a unit for this technology. One important feature of reburn is its compatibility with a particular type of boiler – "Cyclone," – for which the previously mentioned technologies are not particularly well suited. However, this technology has been used only in large EGUs and is not a typical option for ICI boilers. Cyclone boilers are inherently high NOx emitters and are not an attractive option for new or retrofit units with increasingly lower NOx emission limits requirements.

Reburn performance has been shown to range from 30 to 60 percent reduction in NOx emissions, depending on such factors as reburn fuel type and quantity, initial NOx levels, boiler design, etc. Similar to the other combustion modification options, reburn can affect efficiency and fly-ash quality. As such, it requires the same optimum balance between NOx reduction and avoidance of negative impacts. On the other hand, reburn can be thought of as a "dial-in" NOx technology in that NOx reductions are, to a degree, a function of the amount of reburn fuel.

Operating costs are primarily driven by the fuel cost differential in the case of gas reburn, while for coal or oil reburn fuel preparation costs (pulverization and atomization, respectively) represent the dominating O&M costs. Reburn using coal or oil as the reburn fuel does not seem like a very attractive option for ICI boilers for technical reasons (boiler size, residence times), as well as the wider availability of similar performance options simpler to implement, such as LNBs. Gas reburn, while easier to implement, often has a prohibitive operating cost if, for example, natural gas is partially substituted for a less expensive primary fuel. Reburn is therefore an option for larger watertube-type boilers, including stokers, but require appropriate technical and economic analyses to determine suitability. Gas reburn has an impact on CO_2 emissions that is proportional to the type and quantity of fuels displaced (gas vs. coal or oil).

2.3.4 Post-Combustion Controls

Conventional, commercial post-combustion NOx controls include Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). They are fundamentally similar, in that they use an ammonia-containing reagent to react with the NOx produced in the boiler to convert the NOx to harmless nitrogen and water. SNCR accomplishes this at higher

temperatures (1700ºF-2000ºF) in the upper furnace region of the boiler, while SCR operates at lower temperatures (about 700ºF) and hence, needs a catalyst to produce the desired reaction between ammonia and NOx. As noted below, SCR technology is capable of achieving much larger reductions in NOx emissions, higher than 90 percent, compared to the 30 to 60 percent reductions achievable by SNCR. *Figure 2-3* and *Figure 2-4* depict views of these two systems.

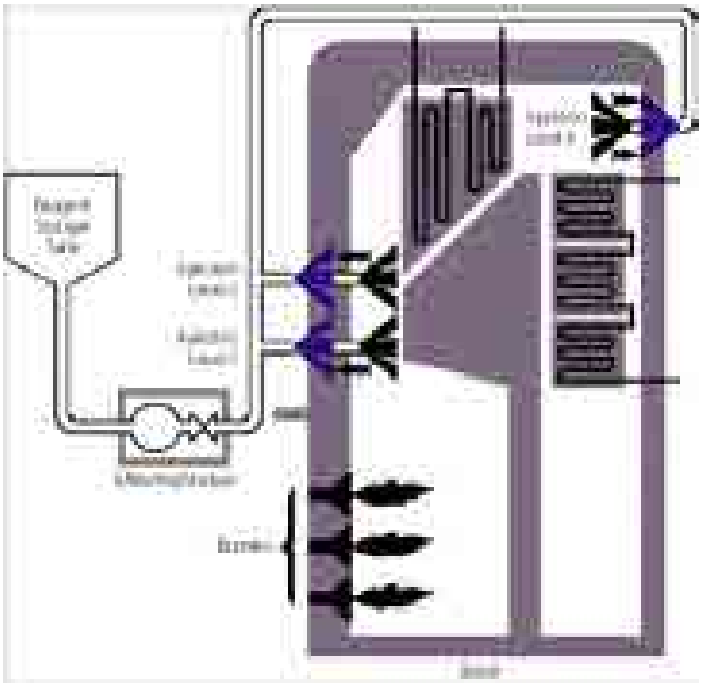


Figure 2-3. SNCR system schematic [FuelTech]

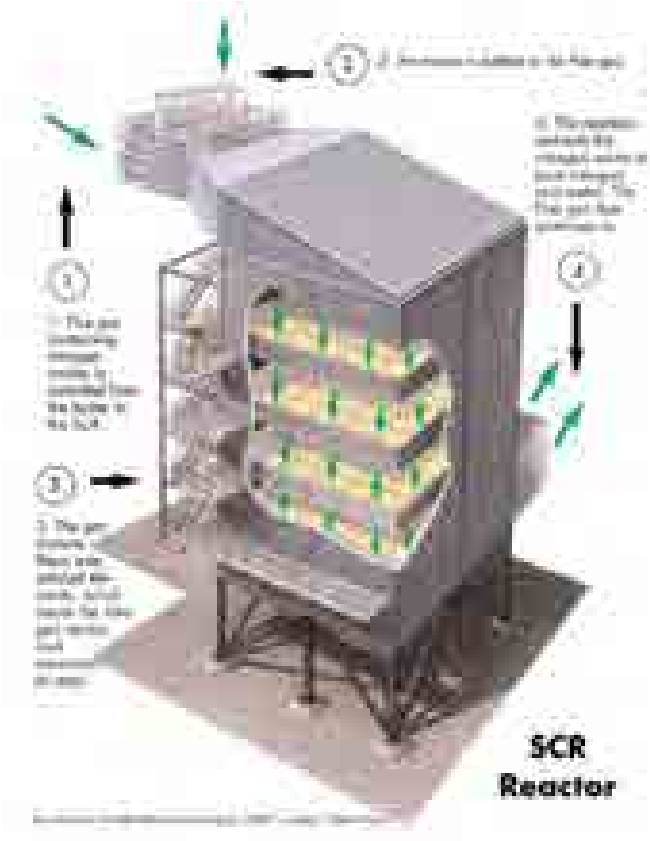


Figure 2-4. 3-D schematic of an SCR system [Alstom Power]

While the difference between the SNCR and SCR may seem minor, it yields significant differences in performance and costs. In the case of SNCR, the reaction occurs in a somewhat uncontrolled fashion (e.g., the existing upper furnace becomes the reaction vessel, which is not what it was originally designed to be), while in the SCR case, a dedicated reactor and the reaction-promoting catalyst ensure a highly controlled, efficient reaction. In practice, this means that SNCR has lower capital costs (no need for a reactor/catalyst); higher operating costs (lower efficiency means that more reagent is needed to accomplish a given reduction in NOx); and finally, has lower NOx reduction capability (typically 30 to 50 percent, with some units achieving reductions in the 60 percent range). SCR, on the other hand, is capital intensive, but offers lower reagent costs and the opportunity for very high NOx reductions (90 percent or higher).

Costs are driven primarily by the consumption of the chemical reagent – usually (but not necessarily) urea for SNCR and ammonia for SCR, which in turn is dependent upon the efficiency of the process (usually referred to in terms of reagent utilization) as well as the initial NOx level and the desired percent reduction. It is also important to consider possible contamination of fly ash (in the case of coal firing) by ammonia making it potentially unable to be sold. This is, again, a bigger issue for larger EGU plants than for ICI boilers due to the size and quantities involved; as already stated, ICIs burning solid fuel do not typically sell their fly ash.

2.3.4.1 RSCR

Commonly, EGU boilers utilize SCR systems to reduce NOx emissions. However, a conventional SCR may not be cost-effective to retrofit into smaller units like ICI boilers because of the extensive modifications required to accommodate the unit. For some applications, the SCR may be located downstream of the particulate control equipment, where the flue gas temperature is much lower than the range of 650-750°F required for a conventional SCR (Toupin, 2007). These conditions are encountered in some ICI boilers firing a variety of fuels, including biomass.

If it is necessary to compensate for the reduction of flue gas temperatures, a regenerative selective catalytic reduction (RSCR^{TM}) system allows the efficient use of an SCR downstream of a particulate control device. The primary application of an RSCR system is the reduction of NOx emissions where the flue gas is typically at 300-400°F (Toupin, 2007). *Figure 2-5* illustrates the schematic and the actual RSCR system. *Figure 2-6* shows a block of ceramic heat exchanger.

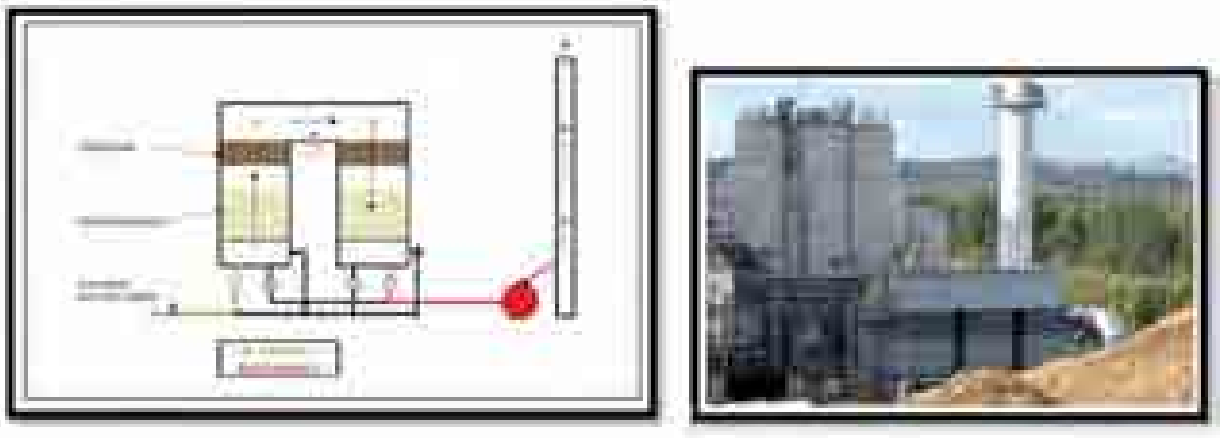


Figure 2-5. Schematic and actual RSCR [Toupin, 2007]

A direct-contact regenerative heater technology (i.e., burner), coupled with cycling beds of ceramic heat exchangers, is used to transfer heat to the flue gas. Additionally, some oxidation of CO to CO_2 in the flue gas occurs. The NOx reduction portion of the RSCR takes place on a conventional SCR catalyst. Either anhydrous or aqueous ammonia can be used.

Figure 2-5 (left side) shows the working principles of the RSCR. Essentially, the flue gas in the space between the two canisters (called the retention chamber) is heated by the burner to make up for heat loss through the walls of the canisters and inefficiency in the ceramic heat transfer modules. This raises the temperature in the retention chamber by about 10-15ºF. The gas flows into the second canister, through the catalyst, and passes through the second ceramic module, which absorbs heat from the hot flue gas. Once this cycle is completed, the flow reverses, so that the second canister (which was just heated) becomes the inlet canister and the first canister becomes the outlet canister. The cycling between canisters accomplishes a similar function to the continuously rotating heating elements of a conventional regenerative air/gas heater.

Other components of the RSCR include the ductwork, fans, and the ammonia delivery system. Ductwork must be adequately sized to provide sufficient distance for ammonia mixing

and to minimize pressure drop. For the ceramic heat exchanger, factors that need to be taken into consideration during the design process are gas-side pressure drop, thermal efficiency, and cost. A large bed face area reduces the pressure drop and operating cost but increases capital cost. The ammonia delivery system consists of ammonia pumps, storage tanks, interconnecting piping, and a control system. The pump typically does not exceed one horsepower and often a redundant pump is provided to assure continuity in system operation [Toupin, 2007].

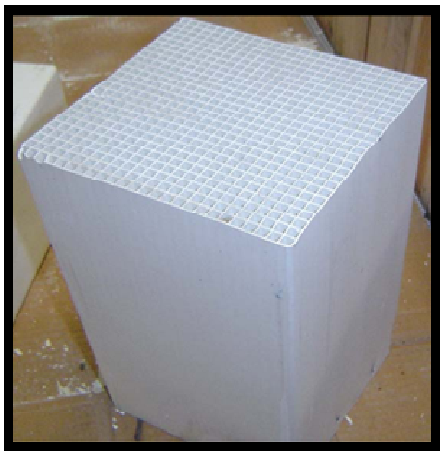


Figure 2-6. Block of monolith ceramic heat exchanger [Toupin, 2007]

The RSCR combines a regenerative thermal oxidizer (RTO) (e.g., retention chamber burner) with SCR technology. This ability to control flue gas temperatures allows for high NOx reduction under varying temperature conditions. *Table 2-1* shows the expected reduction in NOx and CO emissions [BPEI, 2006]. This study indicated that the RSCR is able to reduce NOx by 60 to 75 percent and CO by about 50 percent.

Table 2-1. CO and NOx reduction using RSCR [Source: BPEI 2006]

	Typical Stoker Design	**CO and NOx Reductions from Baseline**
Steam Flow lbs/hr x 10^3	100 – 500	
Steam Press, psi	600 – 900	
Steam Temp., °F	955 – 1000	
Unburned Combustibles Boiler Efficiency Loss (%)	1.0 – 1.5	
Furnace Retention sec.(1)	3.0	
Grate Heat Release Btu/hr-ft	850,000 maximum	
Emissions:		
CO lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.10 – 0.30 (122 – 370)	Base
CO **w/RSCR** lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.05 – 0.15 (61 – 185)	(-50%)
NOx lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.15 – 0.25 (112 – 186)	Base
NOx **w/SNCR** lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.10 – 0.17 (75 – 130)	(-30 to 40%)
NOx **w/RSCR** lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.06 – 0.075 (45 – 56)	(-60 to 75%)

Additionally, the heat exchanger part of the RSCR has a thermal efficiency of about 95 percent, which translates to fuel savings. Traditional technologies that utilize Ljungstrom or plate type heat exchangers for heat recovery and duct burners to reach the catalyst operating temperature are typically in the range of 70 to 75 percent thermal efficiency.

An analysis performed by BPEI on a typical 25 MW plant with a 75 percent reduction in NOx shows a cost effectiveness of $4,514 per ton of NOx removed. The cost breakdown is tabulated below in *Table 2-2*.

Table 2-2. RSCR cost efficiency [BPEI, 2008]

Plant Overview:	
Plant Gross MW	25
GROSS HEAT INPUT, MMBTU/HR	321
TYPICAL UNCONTROLLED NOx, LB/MMBTU	0.25
TYPICAL CONTROLLED NOx, LB/MMBTU	0.065
NOx REMOVED, TONS/YEAR	249.4
RSCR Cost:	
AMMONIA COST, $/TON NOx	$ 419
NATURAL GAS, $/ton NOx	$ 404
POWER COST, $/TON NOx	$ 589
CATALYST COST, $/TON	$ 555
CAPITAL COST, $/TON	$ 2,546
TOTAL COST PER TON NOx REMOVED	$ 4,514

Two RSCR installations (15 and 50MW) are currently in operation in the Northeast. The 15 MW plant uses whole tree chips as fuel; the 50 MW plant uses whole tree chips, waste wood, and construction and demolition wood as fuel for the boilers. The goal of the two installations was to qualify for the Massachusetts Renewable Energy Credits (RECs). The state requirement for qualifying for RECs imposed a NOx level of 0.075 lb/MMBtu or less on a quarterly average basis.

2.3.5 Technology Combinations

In theory, most of the technologies described above can be used together. However, NOx reductions are not necessarily additive, and more importantly, the economics of the combined technologies may or may not be cost-effective. Such analyses are highly specific to the site and strategy. However, several such technology combinations are considered attractive and have gained acceptance. For example, the combination of LNB/OFA with either SCR or SNCR is more prevalent than the application of the post-combustion technologies alone. The economics of this approach are justified by the reduced chemical (SNCR) and capital costs (SCR – smaller reactor/catalyst) due to lower NOx levels entering the SCR/SNCR system. Another combination offered commercially is the hybrid SNCR/SCR concept, which uses the excess ammonia (ammonia “slip”) of the SNCR to promote additional NOx reduction in a downstream SCR catalyst.

2.4 Applicability to ICI Boilers

The NOx control technologies previously described are commercially available and are used extensively in EGUs, but most are also applicable to ICI boilers. Because conventional fuels (e.g., coal, oil, gas) as well as alternative fuels (e.g., wood, petroleum coke, process off-gases) emit NOx, these technologies are applicable to most boilers using various fuels. With the exception of FBC and Stoker boilers, LNBs are available and widely used for most combinations of boiler types and fuels. OFA and reburn as well as SNCR and SCR technologies require site-specific suitability analyses, as several important parameters can have substantial impact on their performance or even retrofit feasibility. As already stated, these include available space, residence times and gas temperatures. Conversely, other than firetube type boilers, these technologies are potential candidates for the other boiler types including stokers and FBCs. Finally, the RSCR may offer advantages for applications where low flue gas temperatures are present and a conventional SCR may be more costly to implement.

2.5 Efficiency Impacts

The NOx control technologies involving combustion modification have essentially no impact on the CO_2 emissions of the host boilers, with the noted exception for reburn when displacing coal or oil with natural gas. This is because combustion modification technologies do not impose any significant parasitic energy consumption (auxiliary power). Note that combustion modification technologies can affect the resulting combustion conditions in addition to the desired reduction in NOx emissions. These impacts are reflected in varying temperatures, oxygen levels, and CO/UBC, all of which affect combustion efficiency as discussed previously. However, we do not attempt to quantify these impacts. The overriding assumption is that these NOx control technologies, once deployed, are optimized such that the resulting NOx emissions are achieved without compromising the above parameters (or at least their combined effects).

With respect to the post-combustion technologies, both SNCR and SCR impose some degree of energy impact on the host boiler. The losses attributable to these technologies include the following:

- For SNCR
  - compressor power (air atomization/mixing)
  - steam (if steam atomization/mixing)
  - dry gas loss (air injection into furnace)
  - water evaporation loss
- For SCR
  - compressor
  - reactor pressure loss
  - steam (sootblowing)

Table 2-3 summarizes the key parameters for major NOx control technologies.

Table 2-3. Summary of NOx control technologies

Technology	Applicability	Performance (% Reduction)	Energy Impacts (kW/1000 acfm)	Comments
LNB	All except Stokers, FBC	30 – 60 (<10ppm possible on gas)	NA	Assumed not to have negative impact on CO/UBC/O_2
OFA	All except firetube/FBC	30 - 60	NA	Assumed not to have negative impact on CO/UBC/O_2
Reburn	All except firetube/FBC	30 - 60	NA	Assumed not to have negative impact on CO/UBC/O_2
SNCR	All except firetube (Must have adequate temperature window)	30 - 70	1 - 2	Compressor/vaporization losses
SCR	All (Most likely for larger coal units where LNBs cannot reach very low NOx levels)	60 - 90	0.5 – 1 (gas) 2 - 4 (oil/coal)	Pressure loss/steam

2.6 NOx Control Costs

The following tables summarize published NOx control costs for ICI boilers reported in the literature [US EPA, 1996; NESCAUM, 2000; Khan, 2003; US EPA, 2003; MACTEC, 2005; Whiteman, 2006]. Literature values of capital cost have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2006 using the Chemical Engineering Plant Cost Index values. Cost effectiveness in dollars per ton of NOx removed is only quoted for the literature references from 2005 or 2006 (and in those year's dollars). Cost effectiveness depends on the operating costs. Reagents or consumables can make up a large portion of some operating costs. Costs of reagents and fuels (e.g., ammonia, natural gas) and consumables (e.g., SCR catalyst) change with time, but not always at the general rate of inflation. Some of these costs have increased at rates higher than the general rate of inflation. Thus, cost effectiveness values (or operating costs) from before 2005 have not been reported.

Table 2-4 summarizes the published NOx control costs for combustion modification technologies. The cost of the installation of low-NOx combustion technology depends on the firing system, and this is reflected in the lack of a clear relationship between capital cost and boiler capacity (*Figure 2-7*). Smaller boilers (10 to 50 MMBtu/hr) are often firetube or packaged watertube, whereas larger oil and gas boilers are more likely to be field-erected watertube boilers. Coal-fired boilers can be stokers, pulverized coal (PC), or cyclones. Combustion modification technologies therefore need to be evaluated on a case-by-case basis, taking into account both the fuel and the design of the combustion system. For the substantial majority of the estimates for ICI boilers, capital costs are in the range of $1,000 to $6,000 per MMBtu/hr. Cost effectiveness values, where available, are generally in the range of $1,000 to $7,000 per ton of NOx removed.

Table 2-4. NOx control costs for combustion modifications applied to ICI boilers

Technology	NOx Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs @2006$ ($/MMBtu/hr)	Base yr. for or Ref. yr	Cost ($/ton NOx @ base year)	Ref
Overfire Air	15-30	Coal	500	$2,682	1996		1
Fuel-Lean GR	35%	Coal	350	$1,302	1999		2
Gas Reburn	55%	Coal	500	$2,604	1999		2
LNB	25%	Coal	350	$6,378	1999		2
LNB	36.0%	Coal	350	$6,378	1999		2
LNB	50%	Coal	500	$8,464	1996		1
LNB	51%	Coal	100	$9,287	1999		6
LNB	51%	Coal	250	$7,055	1999		6
LNB	51%	Coal	1000	$4,654	1999		6
LNB	42.6%	Coal (Tangent.)	250	$5,088	2005	$3,383	3
LNB	42.6%	Coal (Tangent.)	250	$5,088	2005	$3,988	3
LNB	49%	Coal (Wall)	250	$5,088	2005	$2,636	3
LNB	49%	Coal (Wall)	250	$5,088	2005	$3,101	3
LNB	40%	Pulv. Coal	250	$346-$3,610	2005	$749-$3,393	3
LNB	45.0%	Resid. Oil	250-FT	$5,088	2005	$6,361-$7,483	3
LNB	50%	Resid. Oil	250-WT	$5,088	2005	$4,691-$5,519	3
LNB	40%	Resid. Oil	250	$346-$5,088	2005?	$1,505-$6,813	3
LNB	45%	Resid. Oil	10	$7,617	1996		1
LNB	45%	Resid. Oil	50	$3,021	1996		1
LNB	45%	Resid. Oil	150	$1,563	1996		1
LNB	45%	Dist. Oil	10	$7,617	1996		1
LNB	45%	Dist. Oil	50	$3,021	1996		1
LNB	45%	Dist. Oil	150	$1,563	1996		1
LNB	25%	Gas	350	$6,378	1999		2
LNB	40%-55%	Gas	10	$7,617	1996		1
LNB	40%-55%	Gas	50	$3,021	1996		1
LNB	40%-55%	Gas	150	$1,563	1996		1
LNB+FGR	50%	Pulv. Coal	250	$930-6,629	2005	$1,482-$3,582	3
LNB+FGR	72%	Pulv. Coal	250	$930-6,629	2005	$1,029-$2,488	3
LNB+FGR	50%	Resid. Oil	250	$930-6,629	2005	$2,977-$7,197	3
LNB+FGR	72%	Resid. Oil	250	$930-6,629	2005	$2,068-$4,998	3
LNB+OFA	51%-65%	Coal	100	$9,287	1999		6
LNB+OFA	51%-65%	Coal	250	$7,055	1999		6
LNB+OFA	51%-65%	Coal	1000	$4,654	1999		6
LNB+OFA	30%-50%	Oil	100	$3,258	1999		6
LNB+OFA	30%-50%	Oil	250	$2,474	1999		6
LNB+OFA	30%-60%	Oil	1000	$1,633	1999		6
LNB+OFA	60%	Gas	100	$3,258	1999		6
LNB+OFA	60%	Gas	250	$2,474	1999		6
LNB+OFA	60%	Gas	1000	$1,633	1999		6

Table 2-4 [continued]

Technology	NOx Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs @2006$ ($/MMBtu/hr)	Base yr. for or Ref. yr	Cost ($/ton NOx @ base year)	Ref
ULNB	46%	Pulv. Coal	250	$1,364	2005	$1,876	3
ULNB	63%	Pulv. Coal	250	$1,364	2005	$933	3
ULNB	72%	Pulv. Coal	250	$1,364	2005	$619	3
ULNB	75%	Pulv. Coal	250	$1,364	2005	$784	3
ULNB	85%	Pulv. Coal	250	$1,364	2005	$692	3
ULNB	75%	Resid. Oil	250	$1,364	2005	1575	3
ULNB	85%	Resid. Oil	250	$1,364	2005	1390	3
ULNB	80%	Dist. Oil	24.5	$8,619	2005	17954	3
ULNB	80%	Dist. Oil	70	$2,280	2005	5756	3
ULNB	94%	Dist. Oil	68	$1,987	2005	4751	3
ULNB	94%	Dist. Oil	68	$1,987	2005	4564	3

References:

1. US EPA, OTAG Technical Supporting Document, Chapter 5, Appendix C, 1996. http://www.epa.gov/ttn/naaqs/ozone/rto/otag/finalrpt/
2. NESCAUM, *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and I.C. Engines - Technologies & Cost Effectiveness*, (Praveen Amar, Project Director), December 2000.
3. MACTEC, *Boiler Best Available Retrofit Technology (BART) Engineering Analysis*; Lake Michigan Air Directors Consortium (LADCO): March 30, 2005.
4. Whiteman, C., ICAC, "Selective Non-Catalytic Reduction Technology Costs for Industrial Sources," memo to Christopher Recchia, Executive Director, Ozone Transport Commission, October 6, 2006.
5. US EPA Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR); EPA-452/F-03-032, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/fscr.pdf
6. Khan, S. Methodology, Assumptions, and References Preliminary NOx Controls Cost Estimates for Industrial Boilers; US EPA: 2003.

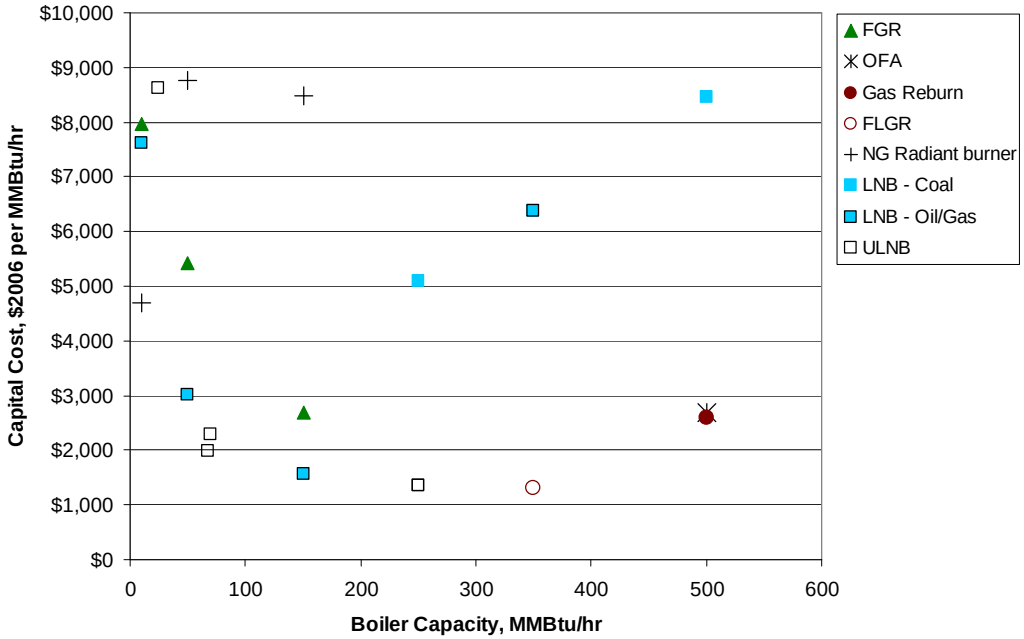


Figure 2-7. Capital cost for NOx control for combustion modification applied to ICI boilers as a function of boiler capacity

Table 2-5. NOx control costs for SNCR applied to ICI boilers

Technology	NOx Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs @2006$ ($/MMBtu/hr)	Base yr. for or Ref. yr	Cost ($/ton NOx @ base year)	Ref.
SNCR	30%-70%	Coal	500	$2,044	1996		1
SNCR	40%	Coal	100	$6,717	1999		6
SNCR	40%	Coal	250	$5,102	1999		6
SNCR	40%	Coal	1000	$3,366	1999		6
SNCR	30%-70%	Resid. Oil	50	$4,297	1996		1
SNCR	30%-70%	Resid. Oil	150	$4,297	1996		1
SNCR	35%		350	$2,862	1999		2
SNCR			21	$17,101	2006	$3,718	4
SNCR			120	$6,377	2006	$2,231	4
SNCR			240	$4,493	2006	$1,821	4
SNCR			387	$2,899	2006	$1,564	4
SNCR			543	$2,319	2006	$1,538	4
SNCR			844	$1,449	2006	$1,346	4
SNCR	40%	Oil	100	$5,205	1999		6
SNCR	40%	Oil	250	$3,954	1999		6
SNCR	40%	Oil	1000	$2,608	1999		6
SNCR	30%-70%	Dist. Oil	50	$4,297	1996		1
SNCR	30%-60%	Natural Gas	50	$4,297	1996		1
SNCR	40%	Gas	100	$5,372	1999		6
SNCR	40%	Gas	250	$4,082	1999		6
SNCR	40%	Gas	1000	$2,693	1999		6
LNB+SNCR	50%-89%	Pulv. Coal	250	$2,064-6,829	2005	$1,409-$4,473	3
LNB+SNCR	50%-89%	Resid. Oil	250	$2,064-6,829	2005	$2,229-$7,909	3

References:

1. US EPA, OTAG Technical Supporting Document, Chapter 5, Appendix C, 1996. http://www.epa.gov/ttn/naaqs/ozone/rto/otag/finalrpt/
2. NESCAUM, *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and I.C. Engines - Technologies & Cost Effectiveness*, (Praveen Amar, Project Director), December 2000.
3. MACTEC, *Boiler Best Available Retrofit Technology (BART) Engineering Analysis*; Lake Michigan Air Directors Consortium (LADCO): March 30, 2005.
4. Whiteman, C., ICAC, "Selective Non-Catalytic Reduction Technology Costs for Industrial Sources," memo to Christopher Recchia, Executive Director, Ozone Transport Commission, October 6, 2006.
5. US EPA Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR); EPA-452/F-03-032, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/fscr.pdf
6. Khan, S. Methodology, Assumptions, and References Preliminary NOx Controls Cost Estimates for Industrial Boilers; US EPA: 2003.

Table 2-5 summarizes the published NOx control costs for SNCR applied to ICI boilers. As with combustion modifications, the capital cost of SNCR systems is sensitive to the type of combustion system. As long as the boiler has sufficient space for installation of injection lances and mixing of reagent and flue gas (at the appropriate temperature), the capital costs should not depend on the fuel burned. The relationship between capital cost and boiler capacity is shown in *Figure 2-8*. Except for the 1996 EPA estimates for gas and oil boilers, there is a pronounced effect of boiler capacity on capital cost. The graph shows that fuel type is probably secondary to boiler capacity, although there will be an indirect effect of fuel, because fuel type influences the design of the combustion system. The cost effectiveness for SNCR was given by ICAC [Whiteman, 2006] without regard to fuel type and by MACTEC [2005] for coal and residual oil.

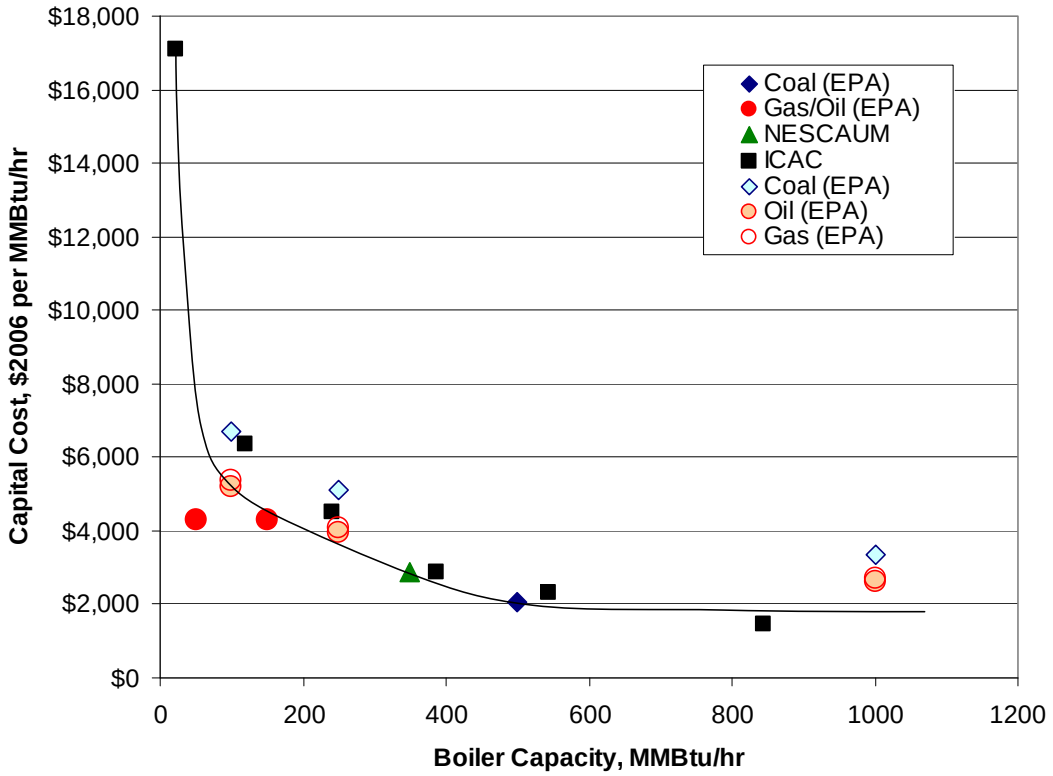


Figure 2-8. Capital cost for NOx control for SNCR applied to ICI boilers as a function of boiler capacity

Table 2-6 summarizes the published NOx control costs for SCR. The relationship between capital cost and boiler capacity is shown in *Figure 2-9*. The capital cost of SCR systems is sensitive to the type of fuel and to the level of NOx reduction desired, but not to the combustion system. The volume of catalyst required for an SCR installation depends on the level of desired NOx reduction and on the fuel. Coal-fired power plant applications are the most expensive, since the flue gas entering the SCR contains fly ash, which affects the design of the catalyst. The capital cost for a given fuel and boiler size can vary (see, for example, the variation in capital costs reported for coal application). When an SCR must be retrofit, the cost of the installation depends on the configuration of the specific system. Because the amount of

ductwork required, significant variation in installed capital cost can occur for a given boiler size. Upgrades like rebuilding the air preheater also affect the installed capital cost. MACTEC [2005] gave the cost effectiveness (in dollars per ton of NOx removed) for SCR for coal and residual oil; these costs showed a wide range, because of the wide range in assumed capital costs.

Table 2-6. NOx control costs for SCR applied to ICI boilers

Technology	NOx Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs @2006$ ($/MMBtu/hr)	Base yr. for or Ref. yr	Cost ($/ton NOx @ base year)	Ref.
SCR	80%	Coal	*350*	$12,755-19,133	1999		2
SCR	80%-90%	Coal	500	$15,365-16,145	1996		1
SCR	70%-90%	Pulv. Coal	250	$1,666-13,881	2005	$2,233-$7,280	3
SCR	80%	Coal	100	$18,574	1999		6
SCR	80%	Coal	250	$14,110	1999		6
SCR	80%	Coal	1000	$9,309	1999		6
SCR	80%	Oil	100	$14,116	1999		6
SCR	80%	Oil	250	$10,723	1999		6
SCR	80%	Oil	1000	$7,075	1999		6
SCR	--	Oil	--	$5,102-7,653	1999		5
SCR	70%-90%	Resid. Oil	250	$1,666-13,881	2005	$4,363-$14,431	3
SCR	80%-90%	Resid. Oil	50	$8,359	1996		1
SCR	80%-90%	Resid. Oil	150	$4,909	1996		1
SCR	80%-90%	Dist.	50	$8,359	1996		1
SCR	80%-90%	Dist.	150	$4,909	1996		1
SCR	80%	Gas	100	$10,216	1999		6
SCR	80%	Gas	250	$7,760	1999		6
SCR	80%	Gas	1000	$5,120	1999		6
SCR	80%	Gas	100	$9,566	1999		2
SCR	80%	Gas	350	$7,015	1999		2
SCR	80%-90%	Natural Gas	50	$8,359	1996		1
SCR	80%-90%	Natural Gas	150	$4,909	1996		1
SCR	80%	Wood	350	$6,378-7,653	1999		2
SCR	74%	Wood	321	$1,978	2006	$4,514	7

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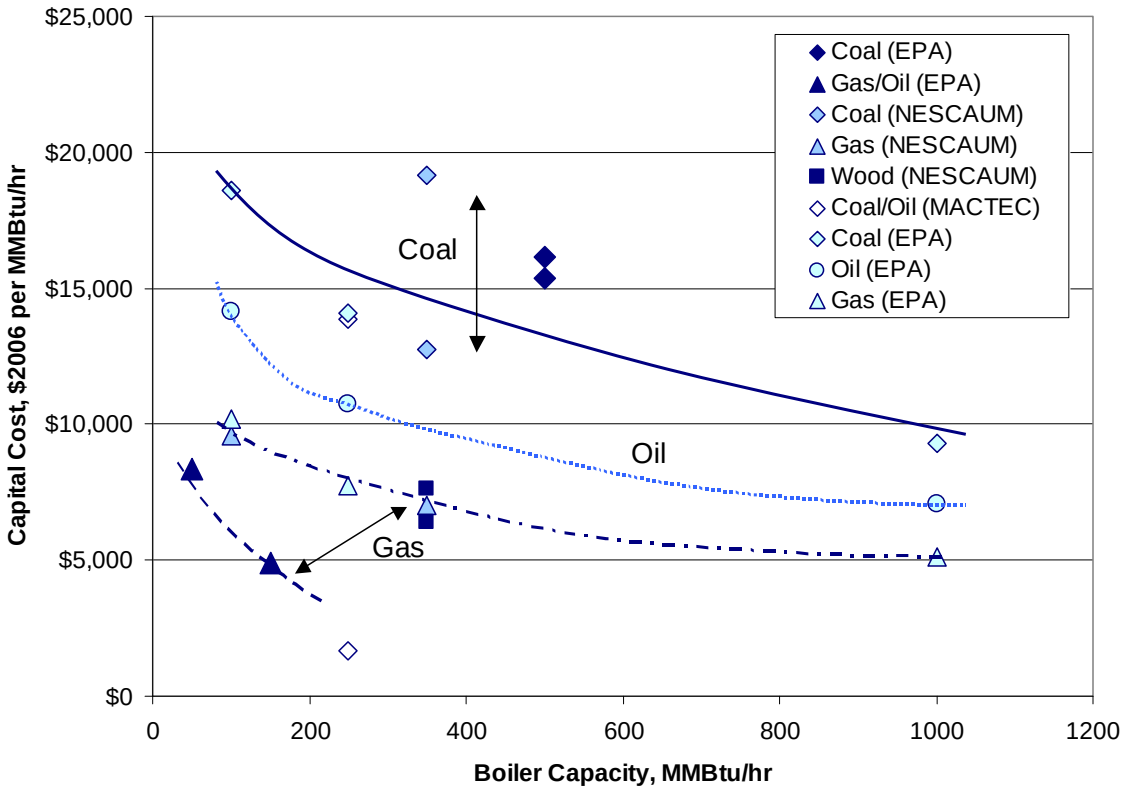


Figure 2-9. Capital cost for NOx control for SCR applied to ICI boilers as a function of boiler capacity

2.7 Chapter 2 References

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3 SO_2 CONTROL TECHNOLOGIES

3.1 SO_2 Formation

SO_2 is an undesirable byproduct of the combustion of sulfur-containing fossil fuels. SO_2, like NOx, is a precursor to ambient fine particles: Thirty to 50 percent of ambient fine PM mass in the eastern U.S. is attributable to sulfate derived from SO_2. SO_2 is a significant contributor to wet and dry acid deposition on various ecosystems (lakes, streams, soils, and forests). Various coals in the U.S. can have 1 to 3 percent (by mass) sulfur; residual oil (No. 6 oil) can have sulfur contents of 2 percent and higher. Distillate oils are generally lower in sulfur content (less than 0.5 percent by mass). Natural gas has essentially zero sulfur content. However, unlike nitrogen in coal or oil, essentially all of the sulfur in the fuel is oxidized to form SO_2 (a very small percentage is further oxidized to SO_3 depending on fuel and boiler characteristics). This means that the relationship between sulfur content in the fuel and SO_2 emissions is much more direct and linear than that between fuel nitrogen and NOx emissions, and as such, the emission reduction benefits of fuel switching (for example from higher- to lower-sulfur coal or from higher-sulfur oils to lower-sulfur oils) are directly proportional to the difference in sulfur contents of fuels.

Another important difference is that this relationship is, for all practical purposes, independent of the type of boiler technology. Two exceptions to this include the high–alkaline nature of ash in some sub bituminous coals, which causes a portion of the sulfur in the coal to react and form various sulfate salts (mostly calcium sulfate); another is the combustion of coal in fluidized bed combustion (FBC) boilers where the lower temperatures of combustion and the use of alkaline material (e.g., limestone) in the "bed" promote the reaction of SO_2 with calcium to form sulfate, thereby reducing the net emissions of SO_2. In practical terms, this means that most solid- and liquid-fuel-fired systems produce SO_2 emissions proportional to their sulfur content, whereas natural gas combustion produces essentially no SO_2.

Additionally, despite the much smaller quantities of SO_3 formed in comparison to SO_2, as noted above, SO_3 presents both operational and environmental challenges. Operationally, SO_3 is a concern because if the temperature of the back-end flue gas handling equipment (e.g., ducts, particulate control devices, scrubbers) falls below the acid dew point, corrosion and material deterioration can result. From an environmental perspective, nucleation and condensation of ultra-fine sulfuric acid particles formed from the SO_3 present in the flue gas can contribute to the primary emissions of fine PM from the stack into the atmosphere.

3.2 SO_2 Reduction

As a result of the relationship between fuel sulfur content and SO_2, SO_2 emission control technologies fall in the category of reducing SO_2 after its formation, as opposed to minimizing its formation during combustion. This is accomplished by reacting the SO_2 in the flue gas with a reagent (usually calcium- or sodium-based) and removing the resulting product (a sulfate/sulfite) for disposal or commercial use, depending on the technology used. SO_2 reduction technologies are commonly referred to as Flue Gas Desulfurization (FGD) or SO_2 "scrubbers" and are usually

described in terms of the process conditions (wet vs. dry), methods for gas-sorbent contact (e.g., absorber vessel vs. duct for dry sorbent injection), byproduct utilization (throwaway vs. saleable), and reagent utilization (once-through vs. regenerable).

Within each technology category, multiple variations are possible and typically involve the type and preparation of the reagent, the temperature of the reaction, and the use of enhancing additives. Because these variations mostly involve complex process chemistry, but are fundamentally similar, this summary focuses on the major categories of SO_2 control technologies, their applicability to ICI boilers, and data on performance and cost. For a more detailed description of FGD technologies, see Srivastava [2000].

As noted earlier, SO_2 control strategies can also include fuel switching (from high-sulfur coal to low-sulfur coal or from high-sulfur oil to low-sulfur oil/natural gas). While not considered a "technology," switching from a higher-sulfur fuel to a lower-sulfur one requires considerable cost and operational analysis. Major issues include price, availability, transportation, and suitability of the boiler or plant to accommodate the new fuel.

3.3 Other FGD Benefits

Significant attention has been given recently to the issue of mercury emissions from EGUs and ICI boilers. It is relevant to note that some FGD technologies have been shown to capture mercury from the flue gas [Jones and Feeley, 2008] by absorbing the water-soluble oxidized forms of mercury from the flue gas. Both wet and dry SO_2 control processes have been and are being tested to determine their mercury capture potential. This suggests that strategic and economic analyses for SO_2 control technologies need to consider the potential side-benefit of mercury removal as well.

3.4 Summary of FGD Technologies

A brief overview of FGD technologies is provided here to give the reader a broad perspective on SO_2 controls.

3.4.1 Wet Processes

Wet FGD (WFGD) or "wet scrubbers" date back to the 1960s with commercial applications in Japan and the U.S. in the early 1970s [NESCAUM 2000]. They represent the predominant SO_2 control technology in use today with over 80 percent of the controlled EGUs capacity in the world and the U.S. [EPA 2000].

In a wet scrubber, the SO_2-containing flue gas passes through a vessel or tower where it contacts an alkaline slurry, usually in a counterflow arrangement. The intensive contact between the gas and the liquid droplets ensures rapid and effective reactions that can yield >90 percent SO_2 capture. Currently, advanced scrubber designs for EGUs have eliminated not only many of the early operational problems, primarily related to reliability, but have also demonstrated very high SO_2 reduction capabilities with the technology being capable of well over 95 percent SO_2 control [Dene *et al.*, 2008]. *Figure 3-1* provides a schematic view of a wet scrubber.



Figure 3-1. Schematic of a WFGD scrubber [Bozzuto, 2007]

Variations of the basic technology, in addition to equipment improvements made over the years, include reagent and byproduct differences. Limestone, lime, sodium carbonate, ammonia, and even seawater-based processes are all commercially available. Limestone is by far the most widely used with commercial-grade gypsum (wallboard quality) being produced in the so-called Limestone Forced Oxidation (LSFO) process. The use of other reagents, as mentioned, is driven by site-specific criteria, such as local reagent availability, economics, and efficiency targets.

Technology costs have changed over time, as expected, reflecting changes in market conditions, labor and raw material costs, local, state, regional, and federal regulatory drivers, and site-specific considerations. Recently, capital costs have trended upward after a downward trend in the mid-late 1990s. These fluctuations have in large part, been driven by labor and material costs, the global nature of technology markets, and regulatory changes within the electric power sector [Sharp, 2007; Cichanowicz, 2007].

3.4.2 Dry Processes

Conventional dry processes include spray dryers (SDs) or "dry scrubbers" and Dry Sorbent Injection (DSI) technologies, and are shown in *Figure 3-2* and *Figure 3-3*, respectively. The technologies are referred to as "dry" because the SO_2 sorbent, while it may be injected as a slurry or a dry powder, is finally dried and collected in a conventional particulate control device, a fabric filter, or an ESP.

SD refers to a configuration where the reaction between SO_2 and the sorbent takes place in a dedicated reactor or scrubber vessel. DSI technology does not require a dedicated reactor and instead uses the existing boiler and duct system as the "reactor," and several configurations are possible based on the temperature window desired. This can occur at the furnace (1800-2200ºF), economizer (800-900ºF), or in a low-temperature duct (250-300ºF). In addition,

another common feature of dry scrubbing systems is the need for the particulate control equipment downstream of the sorbent injection. Usually this is accomplished through the use of fabric filters (although, depending on the application, ESPs may be used) that are not only efficient collectors of fine particulates, but can also provide some additional SO_2 removal as the flue gas passes through unreacted sorbent collected on the bags. Dry processes are more compatible with low- to medium-sulfur coals because of the need to limit solid concentrations in the slurry below a threshold for adequate atomization and the need to limit the amount of solids collected in an existing particulate control device. This requirement precludes higher sulfur fuel applications where the required amount of reagent would be above that threshold. Therefore, high-sulfur applications are more typically associated with wet FGDs.



Figure 3-2. Schematic of a spray dryer [http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm]

It is relevant to note that DSI technology did not gain any meaningful market penetration as part of the EGU compliance options to meet the requirements of the 1990 CAAA (Title IV) "acid rain" legislation for reducing emissions of SO_2. The large number of wet FGD installations in response to the Clean Air Act of 1970, and creation of "emission allowances," combined with the trend to switch fuels (mostly to low-sulfur Powder River Basin or PRB coal) in response to the 1990 CAAA, help explain this situation. However, more recently, interest in DSI technology applications for ICI boilers has been renewed and companies are "revamping" the knowledge base for DSI.

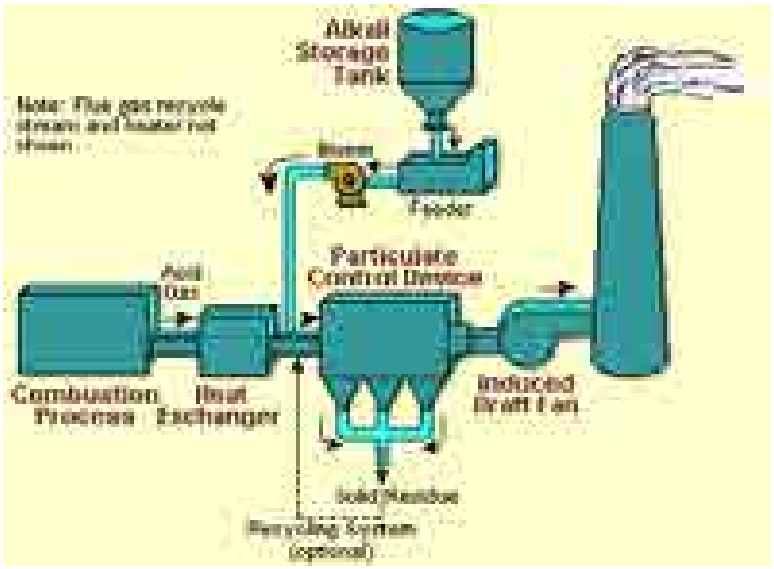


Figure 3-3. Dry Sorbent Injection (DSI) system diagram
[http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm]

DSI technologies include calcium (lime) and sodium (trona) reagents and are currently being tested or demonstrated within the ICI boiler sector. Companies such as O'Brien and Gere [Day, 2006; Day, 2007] and Siemens Environmental [Siemens, 2007] are marketing and deploying duct injection systems, and Nalco Mobotec [Haddad *et al.*, 2003] offers furnace sorbent injection (FSI) systems for ICI boilers. O'Brien and Gere, for example, have conducted over 5,000 hours of demonstrations at 15 different boilers since January 2005 to evaluate the viability, performance, and economics of DSI [Day, 2007]. These processes require relatively little new equipment and are thus suitable candidates for ICI boiler retrofit applications, where site constraints (e.g., space) are often critical.

Two examples of DSI systems are Furnace Sorbent Injection (FSI) in which hydrated lime is injected into the upper furnace of the boiler, and Lime Slurry Duct injection (LSDI) where atomized lime slurry is sprayed into the gas stream in the duct. FSI systems were first demonstrated in the 1980s on EGU boilers and are currently operating at ICI boilers [Dickerman, 2006].

FSI systems are capable of removing between 20 to 60 percent of the SO_2 and have shown removal percentages of as high as 90 to 99 percent for HCl and SO_3 [Haddad *et al.*, 2003]. The FSI systems also offer a low capital cost option and the attractiveness of quick cost recovery for ICI boiler sector [Dickerman, 2006].

The LSDI utilizes an atomized spray of lime slurry. The particles are subsequently captured in the downstream particulate collector. Sorbent particle size distribution is important for maximizing SO_2 capture while minimizing operational problems such as duct fallout and deposition.

LSDI systems have been utilized to mitigate plume generation from cement plants, and are capable of SO_2 reductions of up to 90 percent for industrial applications and ICI boilers, as well as HCl and HF reductions of greater than 95 percent [Dickerman, 2006].

In either case, both dry sorbent injection technologies offer an economical method for reducing emissions of SO_2. *Table 3-1* compares the FSI and LSDI systems for a 100 MW boiler, burning coal with one percent sulfur.

Table 3-1. Comparison of price for FSI and LSDI systems for a 100 MW coal-fired boiler [Dickerman, 2006]

Parameter	***FSI (Hydrated Lime)***	***LSDI***
SO_2 Removal	35%	50%
Reagent Cost (10^3/yr)	$1,400	$370
Parasitic Power (10^3/yr)	$182	$182
Disposal Cost (10^3/yr)	$168	$93
Subtotal (10^3/yr)	$1,750	$645
Capital Cost ($/kW)	$1,000,000 (10 $/kW)	$2,500,000 (25 $/kW)
Annual Capital Charge (10^3/yr)	$100	$250
Total Operating Cost (10^3/yr)	$1,850	$895
$/ton SO_2 Removed	$1,070	$311

Trona (sodium sesquicarbonate) is another reagent that has shown potential to reduce SO_2 emissions. A typical flow diagram is shown in *Figure 3-4* for injection of trona into a duct.

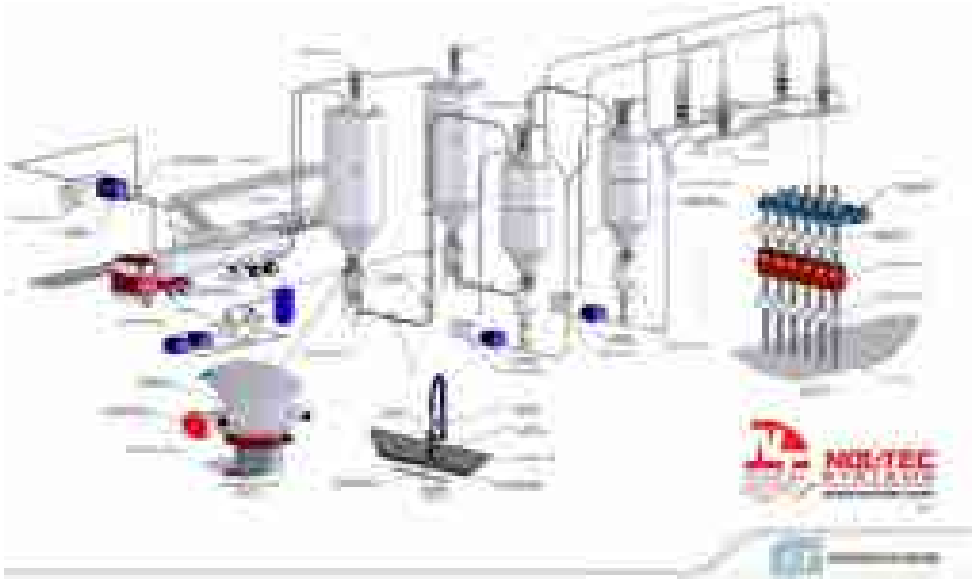


Figure 3-4. Flow diagram for trona DSI system [Day, 2006]

Trona's higher reactivity compared to lime helps it to offset the reaction stoichiometry advantage of lime. More importantly, due to the ability of trona to capture SO_2 when injected at higher temperatures [Cremer *et al.*, 2008], it is potentially applicable to many ICI boilers where flue gas temperatures may be higher that the desired ~300°F required for lime. *Figure 3-5* gives

some test data showing percent SO_2 reduction, [Day, 2006], averaged over several applications for units with ESPs.

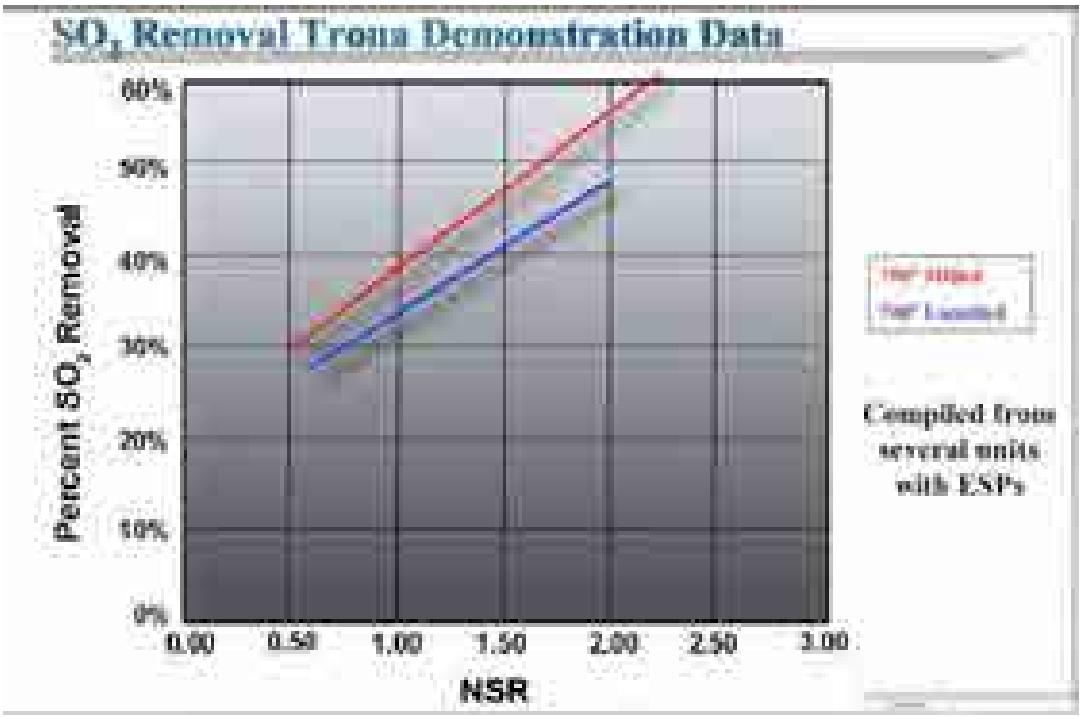


Figure 3-5. SO_2 removal test data [Day, 2007]

Figure 3-5 presents results for SO_2 reduction as a function of normalized stoichiometric ratio (NSR), which is the ratio of the reagent (trona in this case) to SO_2 in the flue gas. The two lines depict SO_2 reduction potential for two different sizes of trona at the same flue gas temperature of 700°F. Larger particles (unmilled) result in lower SO_2 reductions, as expected, relative to the milled condition (smaller particle size).

3.4.3 Other SO_2 Scrubbing Technologies

A number of other scrubber technologies have been developed for control of SO_2, but have not to date received significant market share. Among them are sodium- and ammonia-based wet scrubbing technologies. Some of these technologies, like the activated coke process [Dene, 2008], are regenerable (meaning the reagent can be regenerated and used repeatedly) and may produce useful byproducts, such as sulfuric acid, elemental sulfur, and ammonium sulfate. *Table 3-2* and *Table 3-3* present a comparison of the key performance characteristics and attributes for several alternative scrubbing technologies compared with conventional wet and dry scrubbers [Bozzuto, 2007].

Table 3-2. Comparison of alternative FGD technologies [Bozzuto, 2007]

	Limestone WFGD	Spray Dryer	Ammonia WFGD	Sodium WFGD
Features	• High Efficiency • Low cost reagent • Byproduct flexibility	• Low investment cost • Dry byproduct • Small footprint • No liquid waste	• High value byproduct • Economics improved at high sulfur levels • Low operating cost	• Low investment cost • Operational simplicity
Pros	• Small flue gas flow • Operational simplicity required • Acute capital cost • Short evaluation period	• Low/medium sulfur fuel • Smaller flue gas flow • Short evaluation period	• High sulfur fuel • Larger flue gas flow • Gypsum market •Medium cost evaluation period	• High sulfur fuel • Larger flue gas flow • Fertilizer market
Cons	• Effluent discharge issue	• Limited landfill area • High lime/limestone cost ratio	• Acute capital cost sensitivity • Ultra-low PM emission requirements	• Acute capital cost sensitivity
Reagent	Limestone	Lime	Ammonia	Caustic, soda ash
Byproduct	Marketable gypsum or landfill	Landfill	Fertilizer	Sodium sulfate
SO_2 inlet	High	Low/medium	High	High
Removal Efficiency	>98%	90 – 95%	>98%	>98%

Table 3-3. Cost estimates for alternative FGD technologies [Bozzuto, 2007]

	Limestone WFGD	Spray Dryer	Ammonia WFGD	Sodium WFGD
Capital Cost ($/acfm)	25 – 45	15- 25	35 – 60	10 – 20
Power Consumption (kW/acfm)	3-6	2	3-6	2-3
Reagent Cost ($/ton SO_2 removed.)	$15 – 25/ton	$60 – 75/ton	$80 – 105/ton	$100-130/ton
Byproduct Cost ($/ton SO_2 removed.)	$12 – 20/ton – disposal ($15/ton) – sale	$12 – 20/ton	$150 – 250/ton	??

3.5 Use of Fuel Oils with Lower Sulfur Content

Distillate fuel (No. 2 oil) is used in combustion systems in which an atomizer sprays droplets of oil into a combustion chamber and the droplets burn in suspension. Residual fuel oil (No. 6 oil) is also atomized and burned in ICI boilers. No. 6 oil is more viscous and has a higher boiling point range than distillate oil. Preheating is required for metering and atomization of No. 6 oil in industrial combustion systems. A wide range of sulfur contents are available, from less than 0.3 wt% to greater than 3 wt%.

For oil-fired ICI boilers, switching to lower-sulfur oil can provide significant reductions in emissions of SO_2. There is also an additional and important benefit of reduced emissions of $PM_{2.5.}$ There are generally costs associated with switching to lower-sulfur fuels, which will undoubtedly vary from region to region.

Table 3-4 shows an example of the stocks of the fuel oils available on the East Coast and in the U.S. in 2006, taken from the Energy Information Administration (EIA) Petroleum Supply Annual [US EIA, 2006]. Substantial stocks of low-sulfur No. 6 fuel oil (less than 0.3 percent sulfur) and of ultra-low-sulfur No. 2 fuel oil (less than 0.0015 percent sulfur) were available both in the U.S. and on the East Coast.

Table 3-4. Distillate and residual oil stocks in 2006 (x1000 barrels) [US EIA, 2006]

	East Coast		U. S. Total	
Distillate Fuel Oil	**4,174**		**31,318**	
0.0015% sulfur and under	1,856	(44%)	16,531	(53%)
Greater than 0.0015% to 0.05% sulfur	560	(13%)	6,223	(20%)
Greater than 0.05% sulfur	1,758	(42%)	8,564	(27%)
Residual Fuel Oil	**2,486**		**11,936**	
Less than 0.31% sulfur	869	(35%)	1,291	(11%)
0.31 to 1% sulfur	975	(39%)	2,544	(21%)
Greater than 1% sulfur	642	(26%)	8,101	(68%)

Figure 3-6 shows the prices for residual oil and distillate oil from 1983 through 2007. The differential between low (less than 1 percent sulfur) and high (greater than 1 percent sulfur) sulfur residual oil has been narrowing in recent years. The price of distillate oil in recent years, however, has been at times twice as much as the price of residual oil. The EIA prices for residual oil do not include a breakdown for very low sulfur residual oil (less than 0.31 percent sulfur). However, the prices for No. 2 (distillate) oil are broken out by ultra-low (<15 ppm S), low-sulfur (15-500 ppm S), and high-sulfur (>500 ppm S). These prices, shown in *Figure 3-7*, do not show much difference in price as a function of sulfur content of No. 2 oil.

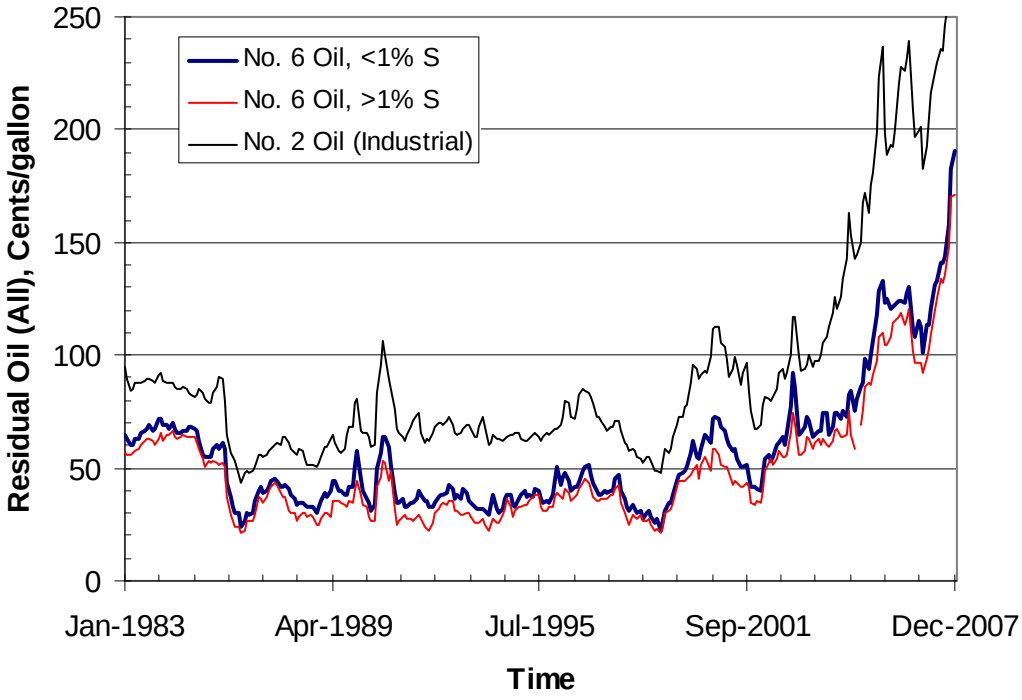


Figure 3-6. Industrial energy prices for No. 6 oil greater than 1 percent S, No. 6 oil less than 1 percent S, and No. 2 oil [Source: US EIA, 2008]

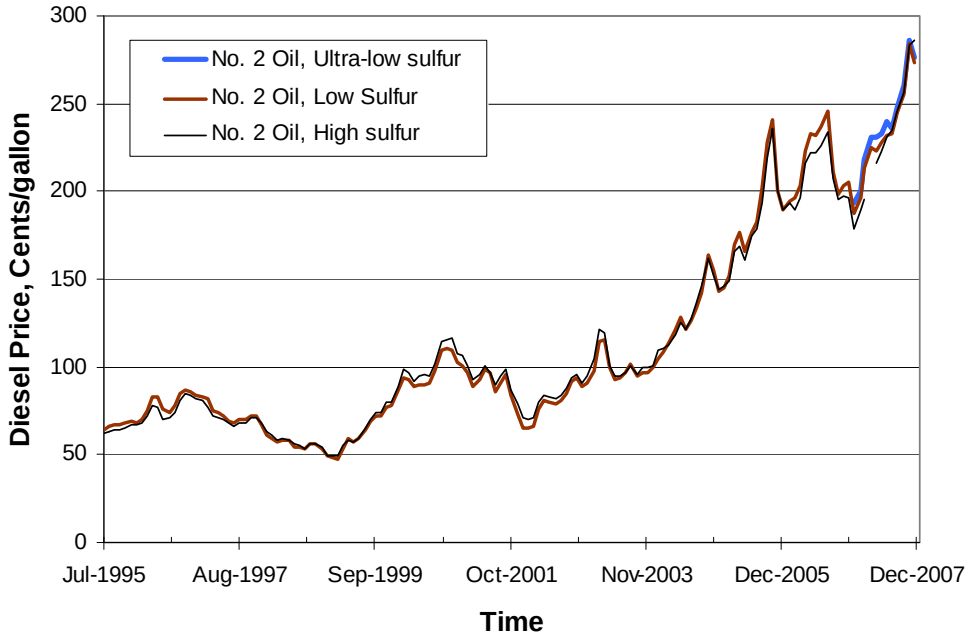


Figure 3-7. Industrial energy prices for No. 2 (distillate) oil [Source: US EIA, 2008]

The potential increased costs (in fuel only) for switching to lower-sulfur fuel oil can be estimated as shown in the following example, in which December 2007 fuel prices are used. If the high-sulfur residual oil is assumed to be 3 percent S, the low-sulfur residual oil is assumed to be 1 percent S, and the distillate oil is assumed to be 0.2 percent S, then the cost for fuel switching is shown in *Table 3-5*. These costs are only fuel costs, and do not include any equipment costs needed to switch fuels (for example, burner changes when switching from residual to distillate oil).

The cost estimates in *Table 3-5* suggest that switching from a 3 percent sulfur residual fuel oil to a low-sulfur residual oil (1 percent S) would provide a cost-effective sulfur removal strategy at about $771 per ton of SO_2 removed. The cost of switching to distillate oil is estimated to be much higher than switching to low-sulfur residual oil, because the cost of distillate oil has been as much as twice that of residual oil in recent years. The cost effectiveness of a wet FGD for 90 to 99 percent SO_2 removal is in the range of $2,000 to $5,200/ton SO_2 (see Section 3.8). Thus, a switch to lower-sulfur fuel represents a cost-effective sulfur-compliance strategy for residual oil-fired boilers. The cost effectiveness (in dollars per ton of SO_2 removed) of switching from residual fuel oil to distillate fuel oil is not as attractive and is in the range of the cost effectiveness of installing a FGD or scrubber.

Table 3-5. Example of costs of switching to low-sulfur fuel oil [Fuel Prices from US EIA, 2008]

Fuel Switch	SO_2 reduction	$/ton SO_2 removed (2007$)
From 3% S to 1% Residual Oil*	66.7%	$771
From 3% S Residual to 0.2% Distillate**	93.6%	$5,335

*Assuming December 2007 prices for <1%S and >1%S residual oil
**Assuming December 2007 prices for >1%S and distillate oil

3.6 Applicability of SO_2 Control Technologies to ICI Boilers

The technologies described above are commercially available and are used extensively throughout the electric utility industry for coal-firing applications. The EGUs have deployed SO_2 controls (mostly wet and dry scrubbers) since the 1970s. ICI boilers firing coal are good candidates for the application of SO_2 control technologies. At least one oil-fired installation of a wet FGD has been noted in the literature [Caine and Shah, 2008]. Economics, however, will dictate preferred options on a case-by-case basis. It is likely that the higher capital-cost intensive technologies (e.g., wet and dry scrubbers) will be most attractive to larger ICI boilers, whereas the injection technologies (such as DSI) would likely be favored at smaller ICI boilers. The annualized cost of a wet FGD scrubber using wet sodium or alkaline waste can be lower relative to lime and limestone FGD, especially if low-cost waste disposal is available and the amount of SO_2 to be removed is small [Emmel, 2006]. This would suggest that smaller ICI boilers may not be good candidates for high capital-cost FGD systems. However, they should be good candidates for application of lower capital cost technologies such as DSI.

In terms of applicability, it is also important to recognize the impact of sulfur content of coal. Dry scrubbing has been typically restricted to low and medium sulfur coals (less than 2 wt% S) due to economic and technical considerations, including constraints associated with sorbent slurry concentration and adequate atomization performance. Lastly, while theoretically feasible, fluidized bed combustion (FBC) boilers are low emitters of SO_2 due to their inherent combustion process (bed temperature and composition), and are not likely candidates for SO_2 scrubber systems.

3.7 Efficiency Impacts

From the brief descriptions above, it should be clear that the common thread among the major SO_2 control technologies involves the reaction of SO_2 in the flue gas with a sorbent or reagent. The chemical reaction occurs either in a dedicated vessel (scrubber), or in the existing flue gas duct system. The major components affecting energy consumption for these systems include electrical power associated with material preparation (e.g., grinding) and handling (pumps/blowers), flue gas pressure loss across the scrubber vessel, and steam requirements. As expected, the energy penalties associated with a highly efficient (99 percent SO_2 reduction) wet scrubber are higher than for a less energy-intensive technology such as DSI.

The power consumption of SO_2 control technologies is further affected by the SO_2 control efficiency of the technology itself. In other words, SO_2 control performance is related to reagent utilization, commonly referred to as liquid-to-gas (L/G) ratio for wet systems and normalized stoichiometric ratio or reagent (Ca or Na) to-sulfur ratio for dry technologies. This can be explained based on the fact that for a given SO_2 reduction level, lower quantities of reagent not only translate to lower reagent costs, but also to lower energy costs.

Table 3-6 summarizes performance and energy efficiency impacts for the three general SO_2 technologies discussed. It is important to note the values shown in the table, specifically in the "Energy Impact" column, represent nominal ranges based on generic combustion calculations and parasitic energy consumption for each technology. They are not site- or fuel-specific calculations, which are generally dependent on many variables, such as fuel composition, combustion and steam efficiencies, and operating conditions (e.g., excess air). However, these values represent broad, industry-wide averages for impacts of SO_2 control technologies on efficiency.

Table 3-6. Summary of energy impacts for SO_2 control technologies

Technology	Applicability	Performance (% Reduction)	Energy Impact (kW/1000 acfm)
WFGD	Larger coal units, high sulfur coals, excluding FBC	90 - 95+	4 – 8+
Dry Scrubbers (SDs)	Larger units w/ low/medium sulfur coals, excluding FBC	70 – 90+	2 - 4
Duct Injection	Larger units w/ low/medium sulfur coals (FBC applications possible for additional "SO_2 trim")	30 – 60+	1 - 2

3.8 SO_2 Control Costs

Table 3-7 summarizes published SO_2 control costs for ICI boilers, as reported in the literature [Khan, 2003; US EPA, 2003; Whiteman, 2003; MACTEC, 2005]. Literature values of capital costs have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2006 using the Chemical Engineering Plant Cost Index values. Cost effectiveness in dollars/ton of SO_2 removed is only quoted for the literature references from 2005 or 2006 (and in those year's dollars). Cost effectiveness depends on the operating costs, and reagents or consumables can make up a large portion of some of the operating costs. Costs of reagents and fuels (e.g., limestone, trona) change with time, but not always at the general rate of inflation. Thus, cost effectiveness values (or operating costs) from years before 2005 are not shown in the table. *Table 3-7* summarizes the published SO_2 control costs for a number of SO_2 control technologies.

A range of capital costs has been reported for sorbent injection technologies. *Figure 3-8* shows costs for dry duct injection (e.g., trona injection), wet duct injection (e.g., LSDI), and furnace sorbent injection (FSI). There was a large range of capital costs reported for dry sorbent injection. Wet sorbent injection (e.g., injection of hydrated lime slurry) was reported to have a significantly lower capital cost than dry sorbent injection. FSI capital costs were between dry and wet duct injection. The cost effectiveness (cost in dollars per ton of SO_2 removed) depends on the specific sorbent used and the stoichiometric ratio of sorbent to SO_2.

Table 3-7. SO_2 control costs applied to ICI boilers

Technology	SO_2 Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs, $2006 per MMBTU/hr	Base year for Costs	Cost Effectiveness ($/ton @Base Yr)	Ref
In-Duct Dry Sorbent Inj.	40%	High-S Coal	100	$34,228	1999		1
In-Duct Dry Sorbent Inj.	40%	High-S Coal	250	$24,028	1999		1
In-Duct Dry Sorbent Inj.	40%	High-S Coal	1000	$15,954	1999		1
In-Duct Dry Sorbent Inj.	40%	Low-S Coal	100	$22,953	1999		1
In-Duct Dry Sorbent Inj.	40%	Low-S Coal	250	$16,565	1999		1
In-Duct Dry Sorbent Inj.	40%	Low-S Coal	1000	$11,031	1999		1
In-Duct Dry Sorbent Inj.	50 - 90%	Coal	100	$17,327	2003		3
In-Duct Dry Sorbent Inj.	50 - 90%	Coal	250	$12,624	2003		3
In-Duct Wet Sorbent Inj.	50 - 70%	Coal	100	$8,663	2003		3
In-Duct Wet Sorbent Inj.	50 - 70%	Coal	250	$4,703	2003		3
In-Duct Wet Sorbent Inj.	50 - 70%	Coal	1000	$4,641	2003		3
Furnace Sorbent Inj.	70%	Coal	100	$26,609	2003		3
Furnace Sorbent Inj.	70%	Coal	250	$14,851	2003		3
Furnace Sorbent Inj.	70%	Coal	1000	$7,054	2003		3
Spray Dryer	90%	Coal	100	$69,744	1999		1
Spray Dryer	90%	Coal	250	$46,209	1999		1
Spray Dryer	90%	Coal	1000	$25,861	1999		1
Spray Dryer	90%	Coal	250	$13,300-188,820	2005	$1,712-3,578	4
Spray Dryer	95%	Coal	250	$13,300-188,820	2005	$1,622-3,390	4
Spray Dryer	90%	Oil	250	$13,300-188,820	2005	$1,944-5,219	4
Spray Dryer	95%	Oil	250	$13,300-188,820	2005	$1,841-4,945	4

Table 3-7 [continued]

Technology	Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs, $2006 per MMBTU/hr	Base year for Costs	Cost Effectiveness ($/ton @Base Yr)	Ref
Wet FGD	90%	High-S Coal	100	$81,939	1999		1
Wet FGD	90%	High-S Coal	250	$62,318	1999		1
Wet FGD	90%	High-S Coal	1000	$41,216	1999		1
Wet FGD	90%	Low-S Coal	100	$76,018	1999		1
Wet FGD	90%	Low-S Coal	250	$57,759	1999		1
Wet FGD	90%	Low-S Coal	1000	$38,122	1999		1
Wet FGD	90%	Coal	250	$11,507-172,672	2005	$2,089-3,822	4
Wet FGD	99%	Coal	250	$11,507-172,672	2005	$1,881-3,440	4
Wet FGD	90%	Oil	100	$69,848	1999		1
Wet FGD	90%	Oil	250	$53,066	1999		1
Wet FGD	90%	Oil	1000	$35,019	1999		1
Wet FGD	90%	Oil	250	$11,507-172,672	2005	$2,173-5,215	4
Wet FGD	99%	Oil	250	$11,507-172,672	2005	$1,956-4,694	4

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3. Whiteman, C., ICAC, "SO_2 Control Technology Cost Estimates for Industrial Boilers" memo to John Robbins, US EPA, December 12, 2003.
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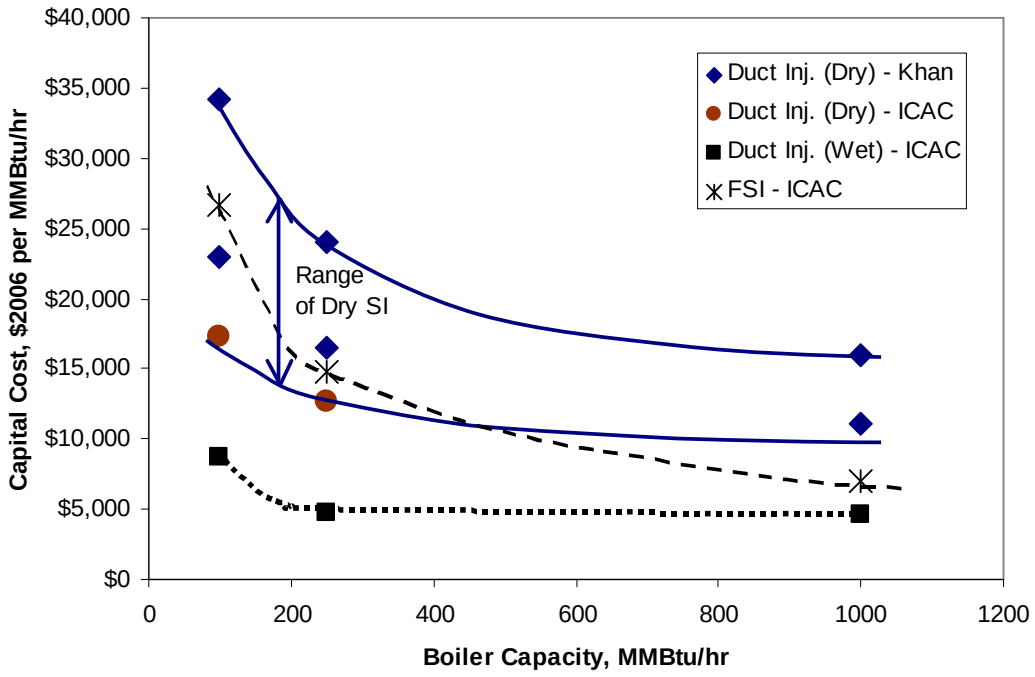


Figure 3-8. Capital cost for SO_2 control for dry sorbent injection applied to ICI boilers as a function of boiler capacity

Spray dryer (SD) technology has been widely applied to coal-fired EGUs. Estimates in the literature for SD technology for ICI boilers give the same capital costs for coal- and oil-fired boilers [ICAC, 2003; MACTEC, 2005]. *Figure 3-9* summarizes these capital costs for ICI boilers. Note that the MACTEC estimates at 250 MMBtu/hr boiler size assumed high and low equipment cost, but a detailed cost breakdown was not given.

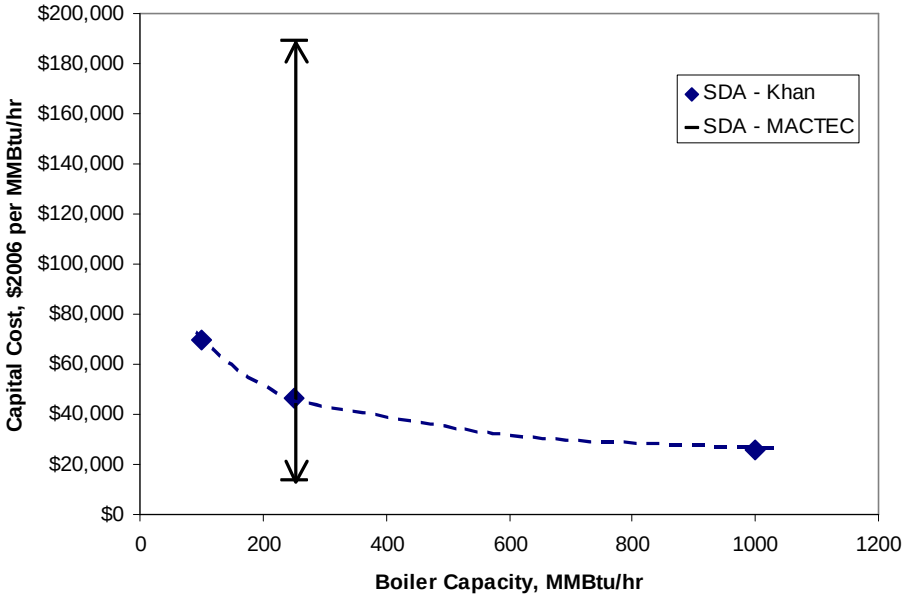


Figure 3-9. Capital cost for SO_2 control for Spray Dryer Absorber applied to ICI boilers as a function of boiler capacity

Wet FGD technology has been widely applied to coal-fired EGU boilers but rarely to ICI boilers, although at least one oil-fired installation has been noted in the literature [Caine and Shah, 2008]. The relationship between FGD capital cost and boiler capacity is shown in *Figure 3-10*. Estimates in the literature give the same capital costs for coal- and oil-fired boilers [ICAC, 2003; MACTEC, 2005], although these estimates are not always based on actual field installation data because installations of wet FGD technology on ICI boilers are few at present.

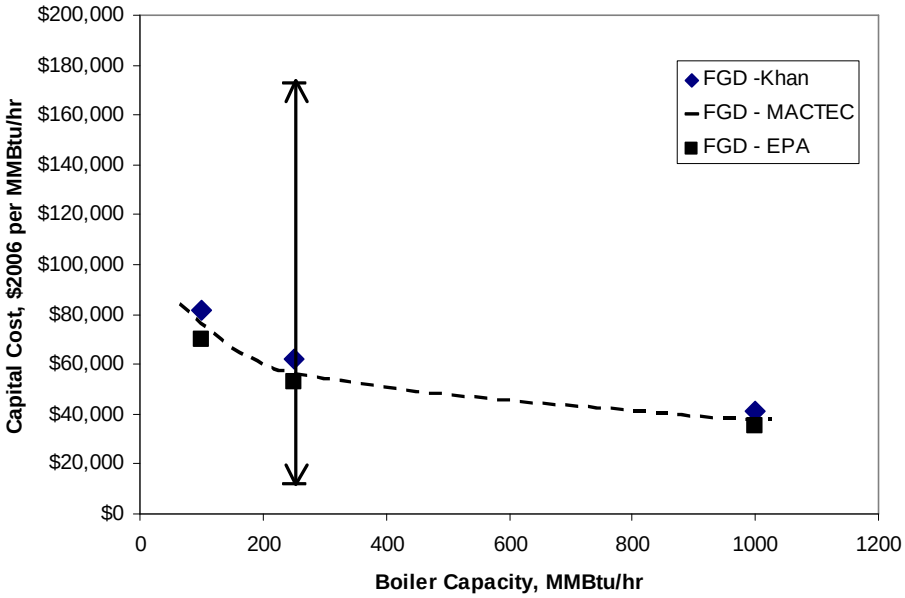


Figure 3-10. Capital cost for SO_2 control for wet FGD applied to ICI boilers as a function of boiler capacity

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4 PM CONTROL TECHNOLOGIES

4.1 PM Formation in Combustion Systems

PM emissions from combustion processes include primary and secondary emissions. Primary emissions consist mostly of fly ash. Secondary emissions are the result of condensable particles such as nitrates and sulfates that typically make up the smaller fraction of the particulate matter (PM_{10} and $PM_{2.5}$). Fly ash refers to the mineral matter of the fuel, which typically includes some level of unburned carbon. ICI boilers burn a variety of fuels that contain ash and, as such, have PM emissions. Therefore, ICI boilers are candidates for PM controls.

Coal and oil contain non-combustible ash material. Other liquid or solid fuels (e.g., petroleum coke, wood) also contain ash. The quantity of ash in the flue gas depends on many factors, such as fuel properties, boiler design, and operating conditions. In dry-bottom, pulverized-coal-fired boilers, approximately 80 percent of the total ash in the as-fired coal exits the boiler as fly ash, and the remaining ash is collected as bottom ash. However, in wet-bottom, pulverized-coal-fired boilers, about 50 percent of the total ash exits the boiler as fly ash. In cyclone boilers (common in the EGU sector but not in the ICI population), most of the ash is retained as liquid slag, and the fly ash is only about 20 percent of the total ash. Fluidized-bed combustors (FBC) emit high levels of fly ash because the coal is fired in suspension and the ash is present in dry form. Stoker-fired boilers can also emit high levels of fly ash. However, overfeed and underfeed stokers emit less fly ash than spreader stokers because combustion takes place in a relatively quiescent fuel bed.

In addition to the nitrates and sulfates mentioned as secondary PM, NOx control technologies that inject ammonia or amine-based reagents (SNCR and SCR) yield a certain amount of ammonia “slip,” which can also form fine particulate (ammonium sulfate) as the flue gas temperatures decrease towards the stack.

This section presents a brief description of the major primary PM technologies.

4.2 PM Control Technologies

PM control technologies have been commercially available and widely used in ICI and EGU boilers for many years. *Table 4-1* summarizes the main types of commercially available technologies.

Table 4-1. Available PM control options for ICI boilers

Technology	Description	Applicability	Performance
Fabric filters (Baghouse)	"Baghouses" made of close-knit fabrics remove particulates through filtration.	Primarily used in coal/wood fired industrial/utility boilers. Not used with oil boilers due to clogging.	>99% total and $PM_{2.5}$ removal
ESPs (Dry/Wet)	Charged particles attracted to oppositely charged plates. Collection method either wet/dry.	Widely used in coal applications. Suitable for oil, pet coke and waste solid fuels. Wet ESPs suitable for saturated flue gas.	Effectiveness depends on resistivity of particulates. Low sulfur can reduce performance of dry ESP. >99% reduction of total PM (dry/wet) and sulfuric acid mist and $PM_{2.5}$ (wet)
Venturi Scrubbers	Scrubbers work on the principle of rapid mixing and impingement of the particulate with the liquid droplets and subsequent removal with the liquid waste.	High pressure required for significant removal. Applicable to a wide range of fuels.	50% removal for fine particulates, 99% removal for large (>5 micron) particulates
Cyclones	Cyclones use aerodynamic forces to separate particles from the gas stream.	Widely applicable to all fuels.	70%-90% total PM potential

4.3 Description of Control Technologies

4.3.1 Fabric Filters

Fabric filters (also called baghouses) are essentially giant vacuum cleaners and very effective devices for collecting dry PM from flue gas. They are used in ICI and EGU applications, although less widely than ESPs. Separation occurs when the ash-laden flue gas passes through a porous layer of filter material. As the individual particles accumulate on the surface of the filter, they gradually form a layer of ash known as the "dust cake." Once formed, the dust cake provides most of the filtration. However, they are not particularly well suited for wet gas applications due to the negative impact of wet gas on the bag filters. *Figure 4-1* shows a photograph of the internal components of a fabric filter compartment with several individual bags and mounting mechanisms.



Figure 4-1. Photograph of fabric filter compartment with filter bags [Source: www.hamon-researchcottrell.com]

As shown in *Figure 4-1*, multiple bags are assembled in compartments to provide a large surface area for filtration. The large surface area is required to maintain acceptable pressure loss across the fabric. Groups of bags are placed in compartments, which can be isolated from one another to allow cleaning of the bags (see below), or to allow replacement of some of the bags without shutting down the entire baghouse.

Baghouse size is typically defined in terms of "air-to-cloth" ratio, expressed in the units of velocity in feet per minute (cubic feet per minute of flow divided by square feet of fabric area). The size of the baghouse depends on the particulate loading and characteristics, and the cleaning method used.

The type of bag cleaning method employed characterizes baghouses. Cleaning intensity and frequency are important because the dust cake provides a significant fraction of the fine particulate removal capability of a fabric. Hence, too frequent or too intense a cleaning method may lower the removal efficiency. Conversely, if removal of this dust cake happens infrequently or inefficiently, the pressure drop will increase to unacceptable levels. The major cleaning methods are as follows.

- Reverse-air baghouse – In this case, the flue gas flows upward through the vertical bags, which open downward. The fly ash thus collects on the insides of the bags, and the gas flow keeps the bags inflated. To clean the bags, a compartment of the baghouse is taken off-line, and the gas flow in this compartment reversed. This causes the bags to collapse, and collected dust to fall from the bags into hoppers.
- Pulse-jet baghouse – In this case, the dust is collected on the outside of the bags, which are mounted on cages to keep them from collapsing. Dust is removed by a reverse pulse of high-pressure air. This cleaning does not require isolation of the bags from the flue gas flow, allowing it to be done on-line. Because pulse-jet cleaning is more intensive than in reverse-air baghouses, the bags in a pulse-jet baghouse remain relatively clean, resulting in the ability to use a higher air-to-cloth ratio or a smaller baghouse compared to the reverse-air type.

Additionally, fabric filters can also be used in applications where fly-ash resistivity makes it difficult for collection with ESPs. Further, baghouses are capable of 99.9 percent removal efficiencies, as well as being able to remove the smaller size PM fraction ($PM_{2.5}$) more efficiently.

4.3.2 Electrostatic Precipitators

ESP's operate on the principle of electrophoresis by imparting a charge to the particulates and collecting them on opposed charged surfaces. Dry vs. wet ESPs refer to whether the gas is water-cooled and saturated prior to entering the charged collection area or is dry. *Figure 4-2* and *Figure 4-3* show schematic views of dry and wet ESPs, respectively. Older ESPs are often of the wire-pipe design, in which the collecting surface consists of one or more tubes (operated wet or dry). The wire-plate design is the other commonly used ESP design, as illustrated in the schematic in *Figure 4-2*.

In gases with high moisture content, dry ESPs are not suitable because the wet gas would severely limit the ability to collect the "sticky" particulates from the plates. The wet ESP technology is capable of very high removal efficiencies and is well suited for the wet gas environments. Both types of ESPs are capable of greater than 99 percent removal of particle sizes above 1 µm on a mass basis with wet ESPs being capable of such reductions well into the sub-micron level (0.01 µm) [Altman, 2001].

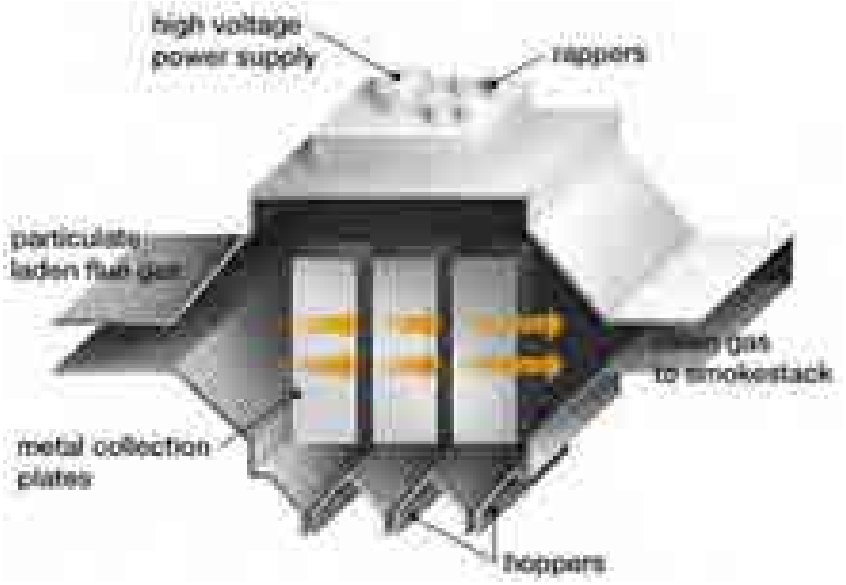


Figure 4-2. Side view of dry ESP schematic diagram [Source: Powerspan]



Figure 4-3. Wet ESP [Croll Reynolds]

Compared to fabric filters, ESPs affect the flue gas flow minimally, resulting in much lower pressure drops then an equivalent baghouse (typically less than two inches H_2O vs. greater than six inches H_2O for the fabric filter).

An electric field between high-voltage discharge electrodes and grounded collecting electrodes produces a corona discharge from the discharge electrodes, which ionizes the gas passing through the precipitator, and gas ions subsequently ionize fly ash (or other) particles. The negatively charged particles are attracted to the collecting electrodes. To remove the collected fly ash, the collecting electrodes are rapped mechanically, causing the fly ash to fall into hoppers for removal.

A balance generally needs to be struck between higher voltages for higher particulate removal efficiency and excessive sparking which will have the opposite effect. Larger ESPs are sectionalized (see *Figure 4-2*) such that higher voltages can be used in the first sections of the precipitator, where there is more particulate to be removed. Lower voltages are then used in the last, cleaner precipitator sections to avoid excessive sparking between the discharge and collecting electrodes. This has the added advantage that particles re-entrained in the flue gas stream by rapping (striking the electrode to dislodge the dust) may be collected in the downstream sections of the ESP.

Precipitator size is a major variable affecting overall performance or collection efficiency. Size determines residence time (the time a particle spends in the precipitator). Precipitator size also is typically defined in terms of the specific collection area (SCA), the ratio of the surface area of the collection electrodes to the gas flow. Higher SCA leads to higher removal efficiencies. Collection areas can range from as low as 200 to as high as 800 ft^2/1000

acfm. In order to achieve collection efficiencies of 99.5 percent, SCA of 350-400 ft²/1000 acfm is typically used. The overall (mass) collection efficiencies of ESPs can exceed 99.9 percent, and efficiencies in excess of 99.5 percent are common. Precipitators with high overall collection efficiencies can achieve high efficiencies across a range of particle sizes so that good control of PM_{10} and $PM_{2.5}$ is possible with well designed and operated electrostatic precipitators.

Unlike dry ESPs, which use rapping to remove particulates from the collecting electrodes, wet ESPs use a water spray to remove the particulates. By continually wetting the collection surface, the collecting walls never build up a layer of particulate matter. This means that there is little or no deterioration of the electrical field due to resistivity, and power levels within a wet ESP can therefore be higher than in a dry ESP. The ability to inject greater electrical power within the wet ESP and elimination of secondary re-entrainment are the main reasons a wet ESP can collect sub-micron particulate more efficiently.

Overall, ESPs have historically been the collection device of choice for many applications in the ICI boiler and EGU boiler sectors. High removal efficiencies are possible and the units are rugged and relatively insensitive to operating upsets. Wet ESPs offer performance characteristics for capturing $PM_{2.5}$ similar to fabric filters and are well suited for applications such as oil firing, for which fabric filters are less attractive, because the sticky ash particles produced from oil combustion can blind the bags.

4.3.3 Venturi Scrubbers

Venturi scrubbers for PM control operate on the principle of rapid mixing and impingement of PM with liquid droplets and subsequent removal with the liquid waste. For particulate controls, the venturi scrubber is an effective technology whose performance is directly related to the pressure loss across the venturi section of the scrubber. However, for higher collecting efficiencies and a wider range of particulate sizes, higher pressure drops are required. High-energy scrubbers operate at pressure losses of 50 to 70 inches of water. Higher pressure drop translates to higher energy consumption. Performance of scrubbers varies significantly across particle size range with as little as 50 percent capture for small (<2 microns) sizes to 99 percent for larger (>5 microns) sizes, on a mass basis. However, venturi scrubbers are seldom used as the primary PM collection device because of excessive pressure drop and associated energy penalties. *Figure 4-4* depicts a venturi scrubber.

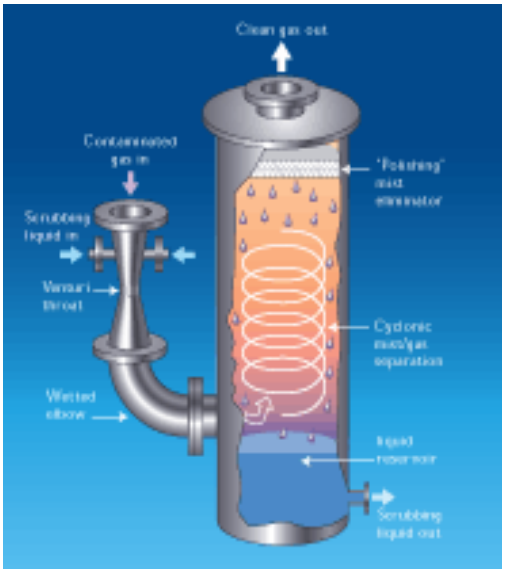


Figure 4-4. Venturi scrubber [Croll Reynolds]

4.3.4 Cyclones

Cyclones are devices that separate particulates from the gas stream through inertial forces. As ash-laden gas enters the cyclone near the top, a high-velocity vortex is created inside the device. Heavy particles move outward due to centrifugal force and begin accumulating on the wall of the cyclone. Gravity continuously forces these particles to move downward where they collect in the lower, hopper region of the cyclone. The collected particles eventually discharge through an opening in the bottom of the hopper into a system that transports the particles to a storage area. Smaller and lighter particles that remain suspended in the flue gas move toward the center of the vortex before being discharged through the clean-gas outlet located near the top of the cyclone (see *Figure 4-5*).

Cyclones are comparatively simple devices in design and construction, with no moving parts. Cyclones can operate over a wide range of temperatures, which makes them attractive for smaller ICI boilers that do not have economizers and/or air preheaters (and thus higher stack temperatures than in EGU boilers). Pressure drops across cyclones are typically in the range of 2 to 8 inches of water for a single cyclone. Cyclones can be arranged in arrays (multi-cyclones) and have overall mass removal efficiencies of 70 to 90 percent with the corresponding increase in pressure drop. However, cyclone collection efficiencies are very sensitive to particle size, and control efficiency for fine particulate ($PM_{2.5}$) is poor [Licht, 1988].

Cyclones are most effective at high boiler loads, where flue gas flow rates are highest. From an operational perspective, cyclones have no moving parts, are not sensitive to fuel quality or gas temperature, and require only regular cleaning to avoid plugging. These characteristics have made them good options in the past, particularly in the absence of regulatory $PM_{2.5}$ requirements.

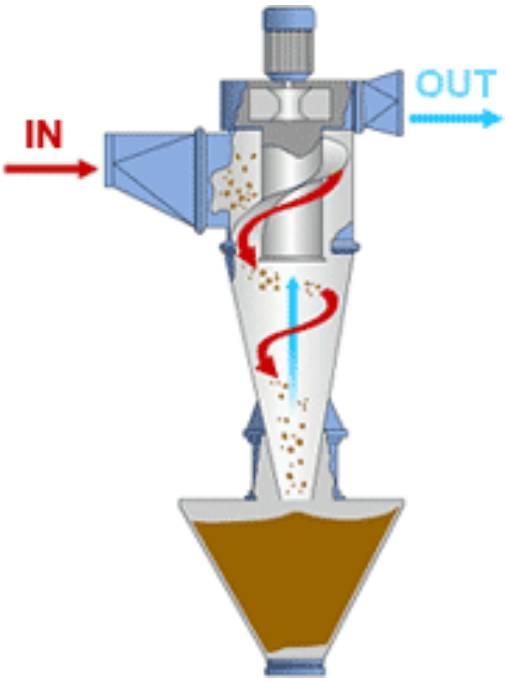


Figure 4-5. Schematic of a cyclone collector [www.dustcollectorexperts.com/cyclone]

Due to the limited potential for $PM_{2.5}$ capture, use of cyclones in new combustion applications is primarily limited to fluidized-bed boilers where they are used to re-circulate the bed material – and not as primary PM control devices.

4.3.5 Core Separator

The core separator is a mechanical device that operates based on aerodynamic separation (like cyclones), but also utilizes a "core separator." The separator portion of the device consists of multiple cylindrical tubes with one inlet and two outlets. One outlet allows for a clean gas stream to exit, while the other outlet is used for recirculating the concentrated stream. This recirculation stream then passes through the cyclone unit (see *Figure 4-6* [Resource Systems Group, 2001]), where it is further cleaned and returned to the separator. This sequential process enhances its overall control efficiency as compared to single or multiple cyclones.

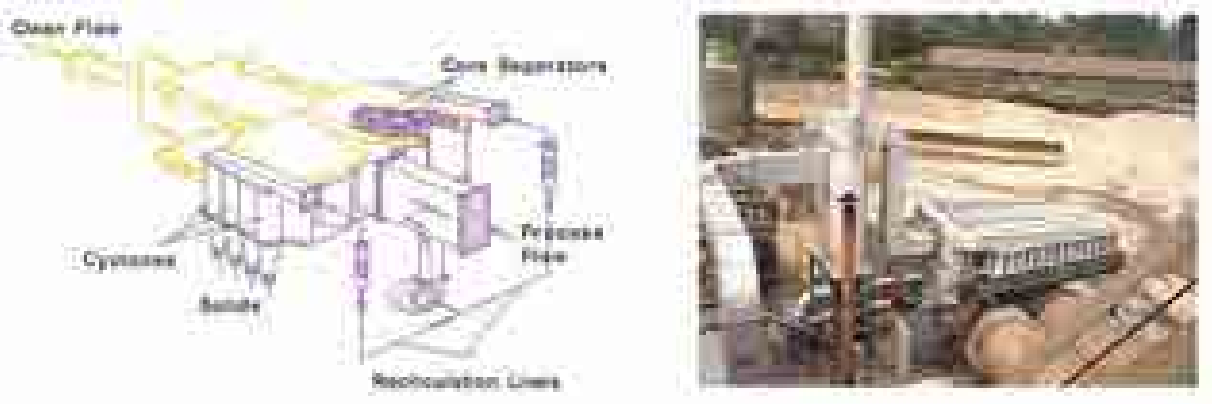


Figure 4-6. Schematic (left) and actual (right) core separator system [EPA, 2003]

The core separator capability for PM removal falls between that of an ESP and a cyclone. Several systems are currently installed on coal- and wood-fired boilers. The core separator unit is capable of overall PM reductions of up to the 90 percent range. Its collection efficiency, however, diminishes to about 50 percent for $PM_{2.5.}$ *Table 4-2* displays inlet and outlet PM concentrations and removal efficiency of a core separator at two different plants. *Table 4-3* presents estimated costs for the core separator for two different sizes and gas flow conditions.

Table 4-2. Core separator collection efficiency [USEPA, 2008; Resource Systems Group, 2001]

Core Separator Inlet Loading (lb/million Btu)	Core Separator Outlet Loading (lb/million Btu)	Removal Efficiency	Boiler Type
0.17	0.07	59%	Wood Fired
0.846	0.214	75%	Stoker – Coal

Table 4-3. Core separator cost analysis [B. H. Eason to P. Amar, 2008]

Boiler Size	MMBtu/hr	8	10
	Estimated gas temperature (°F)	500	500
	Estimated gas flow rate (acfm)	4979	5996
Core Separator Size and Estimated Price (uninstalled)	Gas Flow per 12” module	660	660
	Number of 12” Modules	7	9
	Estimated price	$110,000	$130,000
	Gas Flow per 24” Module	2640	2640
	Number of 24” Modules	1	2
	Estimated Price	$55,000	$83,000

4.4 Applicability of PM Control Technologies to ICI Boilers

The PM control technologies described in this section are widely available and are used in both ICI and EGU applications. Because all these PM controls are based on the collection of particulates from the flue gas, they are applicable to a variety of boiler types and ash-containing

fuels, including coal, oil, wood, petroleum coke, and other waste fuels. Determining the most attractive option for individual applications is a case-by-case decision that needs to account for technical, economic, and regulatory considerations. One exception, as mentioned, is that fabric filters are not suitable for fuel oil applications due to the "stickiness" and composition of the ash.

4.5 Efficiency Impacts

PM control technologies do result in some parasitic energy loss as can be deduced from the brief descriptions of technologies above (see *Table 4-1*). The inherent energy losses associated with each technology are given below and summarized in *Table 4-4*.

- For Fabric Filters
  - compressor (bag cleaning)
  - flue gas pressure loss
  - electric power (heaters, ash handling)
- For ESPs
  - transformer-rectifier (TR) power
  - flue gas pressure loss
  - electric power (heaters, ash handling)
- For Venturi Scrubber and Cyclone
  - flue gas pressure loss

Table 4-4. Summary of energy impacts for control technologies

Technology	Applicability	Performance (% Reduction)	Energy Impact (kW/1000 acfm)	Comments
Fabric Filter	Coal, Wood	99+	1 – 2	Pressure loss / compressor / ash handling
Dry ESP	Coal, Oil, Wood	99	0.5 – 1.5	Pressure loss / TR power / ash handling
Wet ESP	Coal, Oil, Wood	99+	3 - 6	Pressure loss / TR power / ash handling
Venturi Scrubber	Coal, Oil, Wood	70-90 (Not efficient for $PM_{2.5}$)	5 - 11	Pressure loss
Cyclone	Coal, Wood	70-90 (Not efficient for $PM_{2.5}$)	0.5 – 1.5	Pressure loss

4.6 PM Control Costs

The following tables summarize published PM control costs for ICI boilers reported in the literature [US EPA, 2003a; US EPA, 2003b; US EPA, 2003c; US EPA, 2003d; US EPA, 2003e; US EPA, 2003f; MACTEC, 2005]. Literature values of capital cost have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2006 using the Chemical Engineering Plant Cost Index values. Cost effectiveness

in dollars per ton of PM removed is only quoted for the literature references from 2005 or 2006 (and in those year's dollars). Cost effectiveness depends on the operating costs. Reagents or consumables can make up a large portion of some of the operating costs, but these items do not always increase with the rate of inflation for chemical plant equipment. Thus, cost effectiveness values (or operating costs) from years before 2005 have not been reported.

Table 4-5 summarizes the published PM control costs for several different PM control technologies. In the EPA references, the capital costs were given in terms of dollars/scfm (2002 dollars). These costs were converted to dollars per MMBtu/hr using the flow rates given in Chapter Five and then converted to 2006 dollars, using the Chemical Engineering Plant Cost Index values.

The MACTEC capital costs [MACTEC, 2005] span a large range, because high and low estimates for capital equipment were used in the calculation. The EPA capital costs are much higher for the wire-pipe ESP (also known as a tubular ESP) than the wire-plate ESP. Note that a size was not given in the EPA cost estimate, so a range is shown. The capital cost comparison is similar for wet ESPs although the capital costs themselves (in dollars/MMBtu/hr) are higher for wet ESPs as compared to dry ESPs.

For fabric filters, pulse-jet and reverse-air fabric filters were considered. These types of equipment have similar collection efficiencies, but the capital costs and effectiveness of pulse-jet fabric filters are lower than that of reverse-air fabric filters.

Table 4-5. PM control costs applied to ICI boilers

Technology	Reduction Range	Fuel Type	Size of Boiler (MMBtu /hr)	Capital Costs, $2006 per MMBTU/hr	Base year for Costs	Cost Effectiveness ($/ton @Base Yr)	Ref
Dry ESP	90%	Coal	250	$12,365-$160,754	2005	$171-$1,300	7
Dry ESP	99%	Coal	250	$12,365-$160,754	2005	$156-$1,172	7
Dry ESP	90%	Oil	250	$6,713-$87,275	2005	$2,584-$21,009	7
Dry ESP	99%	Oil	250	$6,713-$87,275	2005	$2,328-$18,912	7
Dry ESP (Wire-Pipe)		Coal	--	$6,571-$41,070	2002		1
Dry ESP (Wire-Plate)	90%-99%	Coal	--	$3,286-$10,843	2002		2
Dry ESP (Wire-Pipe)		Resid.Oil	--	$5,198-$32,486	2002		1
Dry ESP (Wire-Plate)	90%-99%	Resid.Oil	--	$2,599-$8,576	2002		2
Dry ESP (Wire-Pipe)		Dist.Oil	--	$5,117-$31,983	2002		1
Dry ESP (Wire-Plate)	90%-99%	Dist.Oil	--	$2,559-$8,443	2002		2
Dry ESP (Wire-Pipe)		Wood	--	$7,560-$47,249	2002		1
Dry ESP (Wire-Plate)	90%-99%	Wood	--	$3,780-$12,474	2002		2
ESP	99.50%	Wood	Small	--	2005	$594	8
ESP	99.50%	Wood	Medium	--	2005	$203-$292	8
ESP	99.50%	Wood	Large	--	2005	$114-130	8
Fabric Filter	90%	Coal	250	$7,453-$93,158	2005	$444-$1,006	7
Fabric Filter	99%	Coal	250	$7,453-$93,158	2005	$423-$957	7
Pulse-Jet Fabric Filter	95%-99.9%	Coal	--	$1,971-$8,543	2002		5
Reverse-Air FF	95%-99.9%	Coal	--	$3,286-$28,585	2002		6
Fabric Filter	90%	Oil	250	$4,046-$50,577	2005	$7,277-$16,464	7
Fabric Filter	99%	Oil	250	$4,046-$50,577	2005	$6,915-$15,643	7
Pulse-Jet Fabric Filter	95%-99.9%	Resid.Oil	--	$1,559-$6,757	2002		5
Reverse-Air FF	95%-99.9%	Resid.Oil	--	$2,559-$22,260	2002		6
Pulse-Jet Fabric Filter	95%-99.9%	Dist.Oil	--	$1,535-$6,652	2002		5
Reverse-Air FF	95%-99.9%	Dist.Oil	--	$2,599-$22,610	2002		6
Fabric Filter	99.50%	Wood	Small	--	2005	$958	8
Fabric Filter	99.50%	Wood	Medium	--	2005	$147-249	8
Fabric Filter	99.50%	Wood	Large	--	2005	$91-$107	8
Pulse-Jet Fabric Filter	95%-99.9%	Wood	--	$2,268-$9,829	2002		5
Reverse-Air FF	95%-99.9%	Wood	--	$3,780-$32,886	2002		6

Table 4-5 [continued]

Technology	Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs, $2006 per MMBTU/hr	Base year for Costs	Cost Effectiveness ($/ton @Base Yr)	Ref
Wet ESP	90%	Coal	250	$25,968-$252,260	2005	$906-$2,627	7
Wet ESP	99.9%	Coal	250	$25,968-$252,260	2005	$815-2,365	7
Wet ESP (Wire-Pipe)	90%-99.9%	Coal	--	$13,142-$65,712	2002		3
Wet ESP (Wire-Plate)	90%-99.9%	Coal	--	$6,571-$13,142	2002		4
Wet ESP	90%	Oil	250	$14,098-$136,955	2005	$14,938-$43,036	7
Wet ESP	99.9%	Oil	250	$14,098-$136,955	2005	$13,446-$38,736	7
Wet ESP (Wire-Pipe)	90%-99.9%	Resid.Oil	--	$10,395-$51,977	2002		3
Wet ESP (Wire-Plate)	90%-99.9%	Resid.Oil	--	$5,198-$10,395	2002		4
Wet ESP (Wire-Pipe)	90%-99.9%	Dist.Oil	--	$10,235-$51,172	2002		3
Wet ESP (Wire-Plate)	90%-99.9%	Dist.Oil	--	$5,117-$10,234	2002		4
Wet ESP (Wire-Pipe)	90%-99.9%	Wood	--	$15,120-$75,599	2002		3
Wet ESP (Wire-Plate)	90%-99.9%	Wood	--	$7,560-$15,120	2002		4

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5 APPLICATION OF A COST MODEL TO ICI BOILERS

When evaluating the applicability of pollution control equipment to a specific ICI boiler, cost and performance capability need to be considered. A number of cost estimation models have been created for estimation of capital and operating costs of retrofit technology for air pollutants. However, most of the cost models have been developed for and applied to EGUs burning coal. Much less work has been carried out on cost estimation models for ICI boilers. In this Chapter, a cost modeling approach currently used for estimating control costs for coal-burning EGUs is modified and then investigated for its applicability to ICI boilers burning coal as well as other fuels. The purpose of this Chapter is to present this modified cost model (CUECost-ICI) and resulting cost calculations. The strengths and weaknesses of this approach are also discussed. However, the purpose of this effort is not to carry out an exhaustive calculation of costs, but to generate a set of reasonable cost estimates for ICI boilers burning different fuels and compare them with published cost information.

5.1 Cost Model Inputs and Assumptions

The Coal Utility Environmental Cost (CUECost) model was developed by Raytheon Engineers for EPA; version 3, and is available on EPA's website at http://www.epa.gov/ttn/catc/products.html. The model calculates capital and operating costs for certain predefined air pollution control devices for control of NOx, SO_2, and PM as applied to coal-fired power plants. The CUECost model produces approximate cost estimates (±30 percent accuracy) of the installed capital and annualized operating costs. The CUECost model was originally designed for and is intended for use on coal-fired boilers greater in size than 100 MW (about 1,000 MMBtu/hr heat input).

Table 5-1 gives the general plant inputs that are needed to set up the model; more inputs are needed for specific air pollution control devices (see Appendix B).

Table 5-1. CUECost general plant inputs

Input Parameter	***Comment***
Location - State	
MW Equivalent of Flue Gas to Control System	*This was designed for EGUs, but can be scaled to generate the appropriate gas flow for ICIs*
Net Plant Heat Rate	*Function of the efficiency of the plant*
Plant Capacity Factor	*Use averages from EEA study, parametric variations*
Percent Excess Air in Boiler	*Assume 3% O_2 for NG and oil, 7% O_2 for coal, wood*
Air Heater In-leakage	*Determines the flow rate for downstream devices such as scrubbers and particulate control devices*
Air Heater Outlet Gas Temperature	
Inlet Air Temperature	
Ambient Absolute Pressure	
Pressure After Air Heater	
Moisture in Air	
Ash Split:	*Depends on firing system*
Fly Ash	
Bottom Ash	
Seismic Zone	
Retrofit Factor	*Moderate effect on total capital requirement (TCR)*
(1.0 = new, 1.3 = medium, 1.6 = difficult)	
Select Fuel	*User can define "coal" with respect to HHV, %S, %ash*

The EPA version of CUECost contains the following modules for specific air pollution control devices:

- Limestone forced-oxidation, wet FGD scrubber
- Lime spray dryer
- FF
- ESP
- SCR
- SNCR
- LNB
- Natural Gas Reburn

CUECost bases the costs of equipment and operation on the generating capacity (in MW of electricity generated) of a given boiler. Industrial boilers are usually rated by the heat input (in MMBtu/hr); the boiler heat rate is used to convert from heat input to the equivalent size in MW. In order to use CUECost in its present form for ICI boilers, an equivalent size in MW needs to be estimated, although this could be modified in a dedicated ICI boiler version of CUECost (which was not developed in this effort).

Industrial boilers are operated differently from utility boilers, and the inputs for CUECost-ICI must be adjusted accordingly, including:

- Heat rate
- Excess air level

- Flue gas temperatures
- Capacity factor

The default values in the current version of CUECost for EGUs generally do not describe ICI boilers well. Fuel compositions vary widely for ICI boilers, while the EGU version of CUECost includes coal as the only fuel option (with different compositions). However, the user can define other fuels, as described below.

An important factor in determining total installed capital cost is the choice of appropriate retrofit factor, which expresses the difficulty of installing a control technology in an existing plant. In CUECost a retrofit factor of 1.0 denotes a new plant (corresponding to the lowest capital cost), and retrofit factors of 1.3 and 1.6 denote medium and difficult retrofits, respectively. Emmel [2006] noted that this range of retrofit factors significantly understated the cost of retrofit for FGD and SCR technologies when applied to EGUs less than 100 MW. Emmel also noted that on average a retrofit factor of 1.45 was more reasonable and that the factor should be even higher when CUECost is applied to ICI boilers.

The technology options in CUECost are also fixed, and the user cannot create a new technology option without supplying formulae for calculating the capital equipment cost. The technology options for SO_2 control in CUECost, in particular, have been noted to be more appropriate for larger utility boilers than for ICI boilers. Wet FGD and spray dryer technology – the SO_2 scrubbing options in CUECost – are based on lime or limestone reagents and have high capital and operating costs compared to alkaline scrubbers or duct injection. The latter scrubbing options might be more attractive for ICI boilers, but would have to be added to the current version of CUECost.

Finally, Emmel [2006] notes that most ICI boiler sites will have higher contingency, general facility, engineering, and maintenance costs (on a percentage of capital cost basis) than those identified for EGUs in CUECost in order to take into account necessary upgrades or demolition of existing facilities that are less likely to be needed at sites.

In this effort, the CUECost model was adapted for ICI boilers burning a variety of fuels by changing the fuel composition and heating value to simulate different fuels. Capital and operating costs in the model were based on correlations derived from coal-fired power plant experience since no reliable field data were available for the ICI boilers. It is not clear how robust the correlations for capital equipment are for small ($\leq$ 25 MW equivalent) boilers.

The CUECost model is based on the electrical generating capacity. A combustion calculation was used to relate heat input rate to equivalent MW for five different fuels.

Table 5-2 gives the properties of these fuels. Boiler efficiency was specified, and heat rate was calculated from boiler efficiency. The uncontrolled or baseline emissions were based on fuel composition (in the case of SO_2 and PM) or on industry operating experience (in the case of NOx).

Table 5-3 shows the results (in terms of calculated flue gas flow rates) of the combustion calculations for a fixed heat input rate of 250 MMBtu/hr or 100 MMBtu/hr. Flue gas flow rate is an important parameter or input to the cost model, because the size of capital equipment is often related to the flue gas flow rate.

Table 5-2. Fuel characteristics and assumptions for CUECost calculation of heat rate and flue gas flow rates

	Bituminous	Wood	No.2 Oil	No.6 Oil	Gas
C, wt%	76.2	27.6	86.4	85.8	75
S, wt%	2.5	0.04	0.6	2.5	0
H, wt%	4.6	3.3	12.7	10.6	25
Moisture, wt%	1.4	45	0.02	0.02	0
N, wt%	1.4	0.3	0.1	0.5	0
O, wt%	7	22.86	0.1	0.5	0
Ash, wt%	6.9	0.9	0.08	0.08	0
Fuel heating value, BTU/lb	13,630	4,633	19,563	18,273	20,800
Unburned carbon, wt% in ash	5	1	75	75	0
Boiler efficiency*	34%	30%	39%	39%	45%
Stack O_2, vol% dry	7%	7%	3%	3%	3%
Boiler heat rate, Btu/kWh	10,000	11,370	8,750	8,750	7,600
Uncontrolled or Baseline emissions NOx, lb NO_2/MMBtu	0.60	0.26	0.20	0.40	0.40
SO_2, lb/MMBtu	3.67	0.17	0.61	2.74	0.00
PM, lb/MMBtu	5.06	1.94	0.04	0.04	0.00

***Fuel to MW

Table 5-3. Equivalent heat input rate and flue gas flow rates for 250 and 100 MMBtu/hr heat input rates

	MW	MMBtu/hr	Flue gas, scfm
Bituminous coal (34% efficiency, 7% O_2)	25.0	250	65,305
Wood (30% efficiency, 7% O_2)	22.0	250	81,184
No.2 oil (39% efficiency, 3% O_2)	28.6	250	50,622
No.6 oil (39% efficiency, 3% O_2)	28.6	250	51,117
Natural gas (45% efficiency, 3% O_2)	32.9	250	59,336
Bituminous coal (34% efficiency, 7% O_2)	10.0	100	26,122
Wood (30% efficiency, 7% O_2)	8.8	100	32,474
No.2 oil (39% efficiency, 3% O_2)	11.4	100	20,178
No.6 oil (39% efficiency, 3% O_2)	11.4	100	20,375
Natural gas (45% efficiency, 3% O_2)	13.2	100	23,806

5.2 Comparison of the Cost Model Results with Literature

A comparison was made of the CUECost-ICI model with other published information for a selection of fuels and air pollution control devices applied to ICI boilers. Where possible, the inputs for the model were set to be the same as information cited in the literature.

Using the appropriate fuel composition and boiler heat rates, the modified ICI version of the original CUECost (CUECost-ICI) model was run for a number of ICI boiler cases. *Table 5-4*, *Table 5-5*, and *Table 5-6* show the installed capital costs, first-year annual operating costs, and cost per ton of pollutant removed for NOx, SO_2, and PM, respectively. Capital and operating costs were calculated on 2006 dollars basis in the CUECost-ICI model. A complete

list of inputs to CUECost-ICI is included in Appendix B. For the NOx and SO_2 control technologies, percentage reduction of the pollutant was used as an input, so that the CUECost-ICI results could be easily compared to published literature results. For PM controls, a specific emission limit (in lb/MMBtu) was used as an input and the percentage PM reduction was calculated from the fuel ash content.

Table 5-4. Capital and operating costs for NOx control technologies (assuming 7.5 percent interest and 15-year project life)

MMBtu/hr	Pollutant removal efficiency	Fuel	Technology	Reagent	Installed Capital Cost, $M	Annual Cost, $M	Cost/ton
250	80.0%	Coal	SCR	Ammonia	$4.394	$1.253	$4,763
100	80.0%	Coal	SCR	Ammonia	$2.585	$0.702	$6,668
250	80.0%	No.6 Oil	SCR	Ammonia	$2.923	$0.790	$3,972
100	80.0%	No.6 Oil	SCR	Ammonia	$1.760	$0.460	$5,805
250	80.0%	Nat.Gas	SCR	Ammonia	$3.005	$0.811	$4,673
100	80.0%	Nat.Gas	SCR	Ammonia	$1.805	$0.472	$6,777
250	50.0%	Coal	SNCR	Ammonia	$1.142	$0.398	$2,422
100	50.0%	Coal	SNCR	Ammonia	$0.969	$0.317	$4,817
250	50.0%	No.6 Oil	SNCR	Ammonia	$0.724	$0.338	$2,722
100	50.0%	No.6 Oil	SNCR	Ammonia	$0.407	$0.196	$3,961
250	50.0%	Nat.Gas	SNCR	Ammonia	$0.785	$0.362	$3,335
100	50.0%	Nat.Gas	SNCR	Ammonia	$0.443	$0.209	$4,798
250	40.0%	Coal	LNB	--	$1.227	$0.301	$2,290
100	40.0%	Coal	LNB	--	$0.677	$0.166	$3,155
250	40.0%	No.6 Oil	LNB	--	$1.339	$0.329	$3,305
100	40.0%	No.6 Oil	LNB	--	$0.737	$0.181	$4,559
250	40.0%	Nat.Gas	LNB	--	$1.467	$0.360	$4,151
100	40.0%	Nat.Gas	LNB	--	$0.810	$0.199	$5,715

Table 5-5. Capital and operating costs for SO_2 control technologies (assuming 7.5 percent interest and 15-year project life)

MMBtu/hr	Pollutant removal efficiency	Fuel	Technology	Reagent	Installed Capital Cost, $M	Annual Cost, $M	Cost Effectiveness (dollars per ton)
250	95%	Coal	wFGD	Limestone	$38.096	$11.137	$4,427
100	95%	Coal	wFGD	Limestone	$33.680	$9.608	$9,547
250	95%	No.6 Oil	wFGD	Limestone	$36.642	$10.733	$5,713
100	95%	No.6 Oil	wFGD	Limestone	$32.805	$9.368	$12,510
250	90%	Coal	SD	Lime	$29.598	$8.806	$3,694
100	90%	Coal	SD	Lime	$26.263	$7.540	$7,909
250	90%	No.6 Oil	SD	Lime	$28.463	$8.371	$4,704
100	90%	No.6 Oil	SD	Lime	$25.723	$7.344	$10,352

Table 5-6. Capital and operating costs for PM control technologies (assuming 7.5 percent interest and 15-year project life)

MMBtu/hr	Pollutant removal efficiency	Fuel	Technology	PM Emission, lb/MMBtu	Installed Capital Cost, $M	Capital cost, $/scfm	Capital cost, $/acfm	Annual Cost, $M	Cost Effectiveness (dollars per ton)
250	99.3%	Coal	ESP	0.03	$4.05	$62.00	$43.00	$1.11	$342
100	99.3%	Coal	ESP	0.03	$2.31	$88.50	$61.50	$0.63	$485
250	99.3%	Coal	FF	0.03	$4.77	$73.00	$50.70	$1.32	$406
100	99.3%	Coal	FF	0.03	$2.88	$110.20	$76.60	$0.78	$592
250	95.8%	No.6 Oil	ESP	0.01	$3.40	$66.60	$46.30	$0.93	$5,689
100	95.8%	No.6 Oil	ESP	0.01	$2.02	$99.00	$68.80	$0.55	$8,410
250	95.8%	No.6 Oil	FF	0.01	$4.09	$80.00	$55.60	$1.14	$6,940
100	95.8%	No.6 Oil	FF	0.01	$2.50	$122.80	$85.30	$0.68	$10,354

For comparison, the American Forest & Paper Association (AF&PA) calculated SNCR control costs in 2006 for wood-fired boilers ranging in size from 88 to 265 MMBtu/hr [Hunt, 2006]. *Table 5-7* below compares the AF&PA costs with the CUECost-ICI costs for wood-fired boilers. The installed capital cost values agree well between CUECost-ICI and the AF&PA estimates, although the CUECost-ICI values for cost effectiveness (dollars per ton of NOx removed) are 20 to 25 percent lower than the AF&PA estimates.

Table 5-7. Capital and operating costs for SNCR on wood-fired boilers, comparison of cost calculations from AF&PA and CUECost

MMBtu/hr	Pollutant removal efficiency	Fuel	Technology	Reagent	Installed Capital Cost, $M	Annual Cost, $M	Cost, $/ton
AF&PA							
88.5	70.0%	Wood	SNCR	Urea	$0.924	$0.250	$11,283
176.9	70.0%	Wood	SNCR	Urea	$1.400	$0.384	$8,574
285.4	70.0%	Wood	SNCR	Urea	$1.786	$0.502	$7,480
CUECost							
88.5	70.0%	Wood	SNCR	Urea	$0.923	$0.289	$9,239
176.9	70.0%	Wood	SNCR	Urea	$1.025	$0.324	$5,174
285.4	70.0%	Wood	SNCR	Urea	$1.130	$0.361	$5,011

Finally, the CUECost-ICI model results for capital cost were compared with some of the values reported in the literature [US EPA, 1996; NESCAUM, 2000; US EPA, 2003a; US EPA, 2003b; Whiteman, 2006], where available. Literature values of capital costs have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2006 using Chemical Engineering Plant Cost Index values.

The NOx capital costs computed with CUECost-ICI were largely consistent with the literature values. (Chapter Two contains a detailed discussion of the literature values for NOx control costs.)

Figure 5-1 compares capital costs for SCR for boilers burning coal, residual (No. 6) oil, and natural gas. The SCR costs appear to be consistent with the literature values. The literature value for SCR as reported by the Ozone Transport Assessment Group (OTAG) [US EPA, 1996] did not describe its basis in any detail, so it is difficult to determine if the OTAG cost estimates assumed a significantly different space velocity or different equipment than assumed in the CUECost-ICI model.

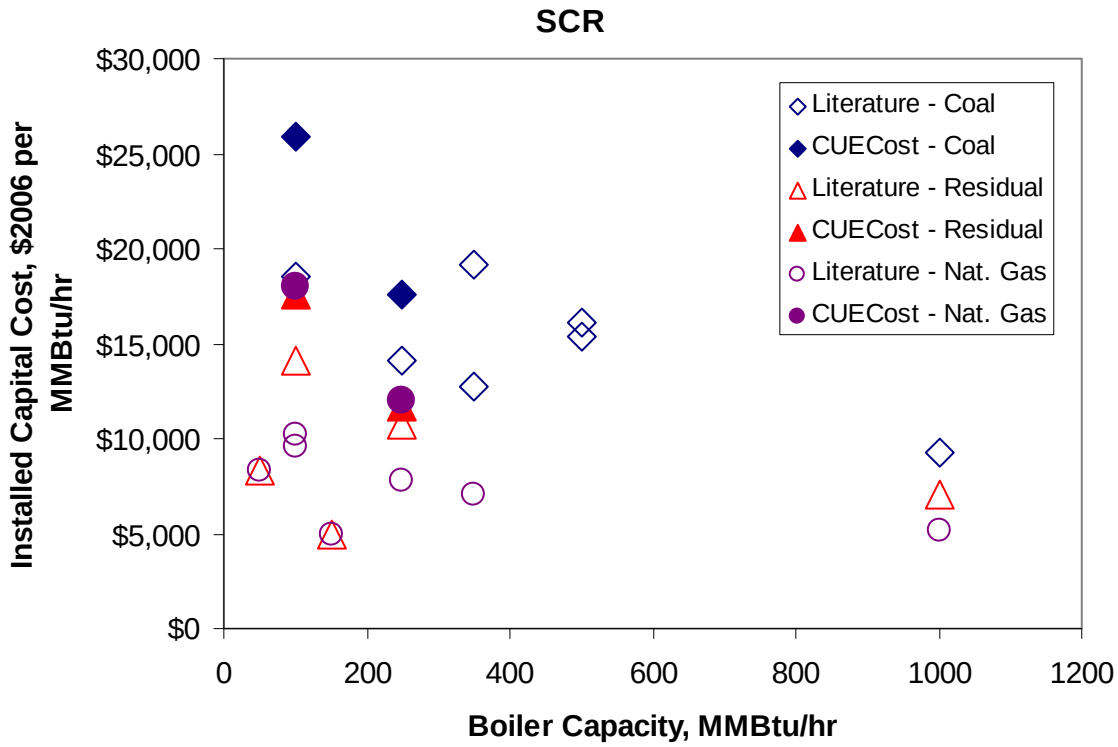


Figure 5-1. Comparison of CUECost-ICI model and reported literature values for capital cost of SCR for NOx control

The capital costs for SNCR (*Figure 5-2*) calculated from the CUECost-ICI model are in good agreement with literature values, particularly the sensitivity of capital cost to boiler capacity, which was also noted by ICAC [Whiteman, 2006].

The capital costs for LNB (*Figure 5-3*) calculated from the CUECost-ICI model for coal-fired boilers were consistent with the literature values, although the capital costs for residual oil-fired boilers were higher in the CUECost-ICI model than the literature values. Again, no details were provided in the literature references.

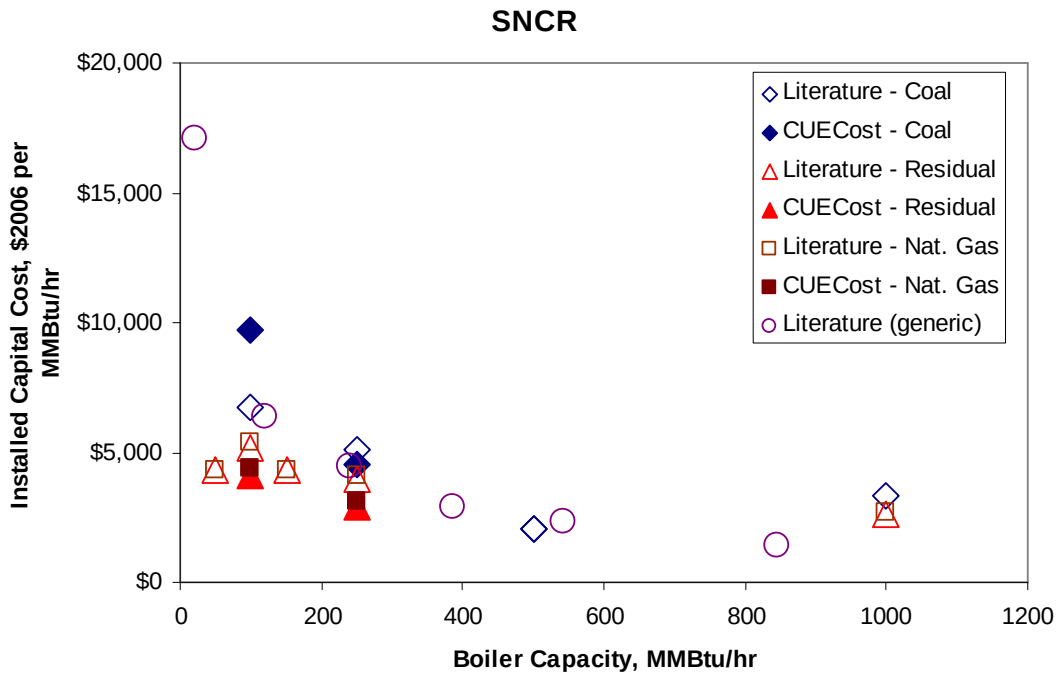


Figure 5-2. Comparison of CUECost-ICI model and reported literature values for capital cost of SNCR for NOx control

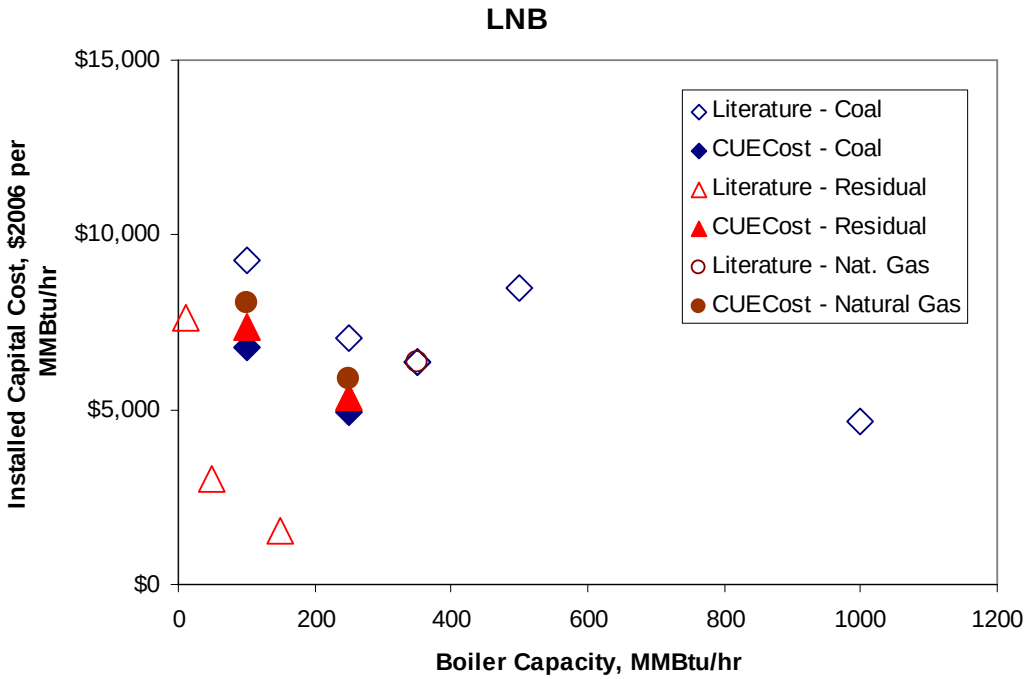


Figure 5-3. Comparison of CUECost-ICI model and reported literature values for capital cost of LNB for NOx control

Chapter Three contains a detailed discussion of the literature values for SO_2 control costs. The SO_2 capital costs computed with CUECost-ICI for spray dryers (SDs) were in the range of the literature values at boiler size of 250 MMBtu/hr (*Figure 5-4*). No literature data were available for residual oil-fired boilers and spray dryers. However, the capital costs calculated by CUECost –ICI for wet FGDs (*Figure 5-5*) were high when compared to the literature values.

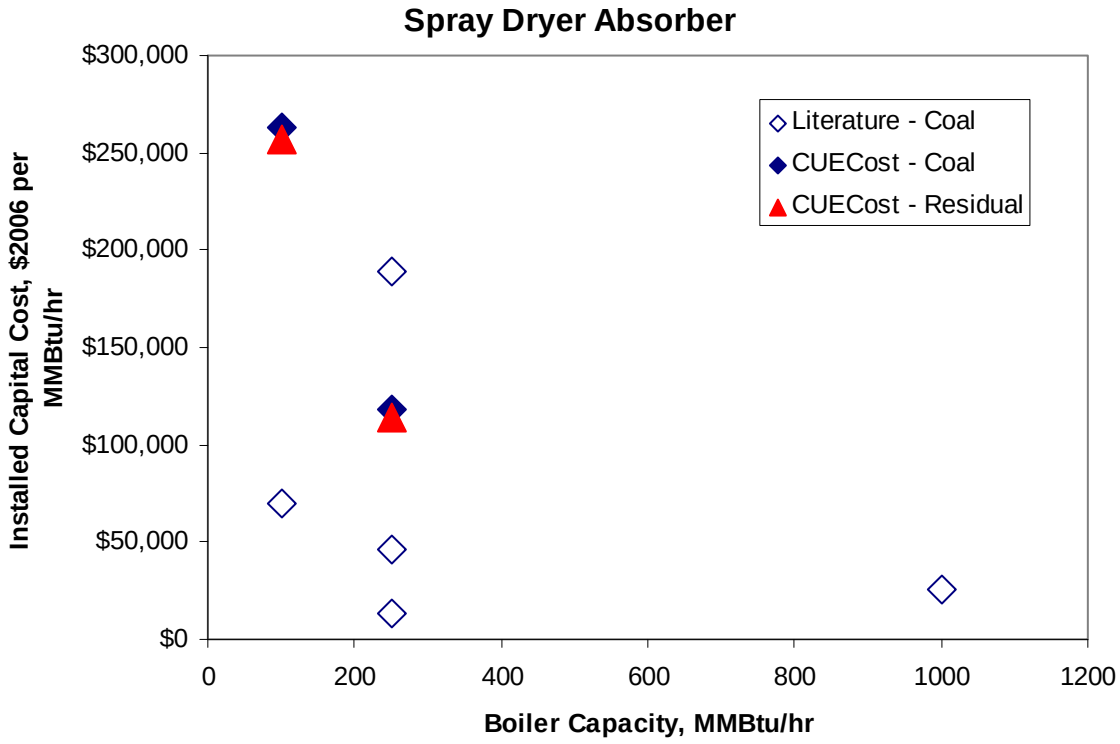


Figure 5-4. Comparison of CUECost-ICI model and reported literature values for capital cost of Spray Dryer for SO_2 control

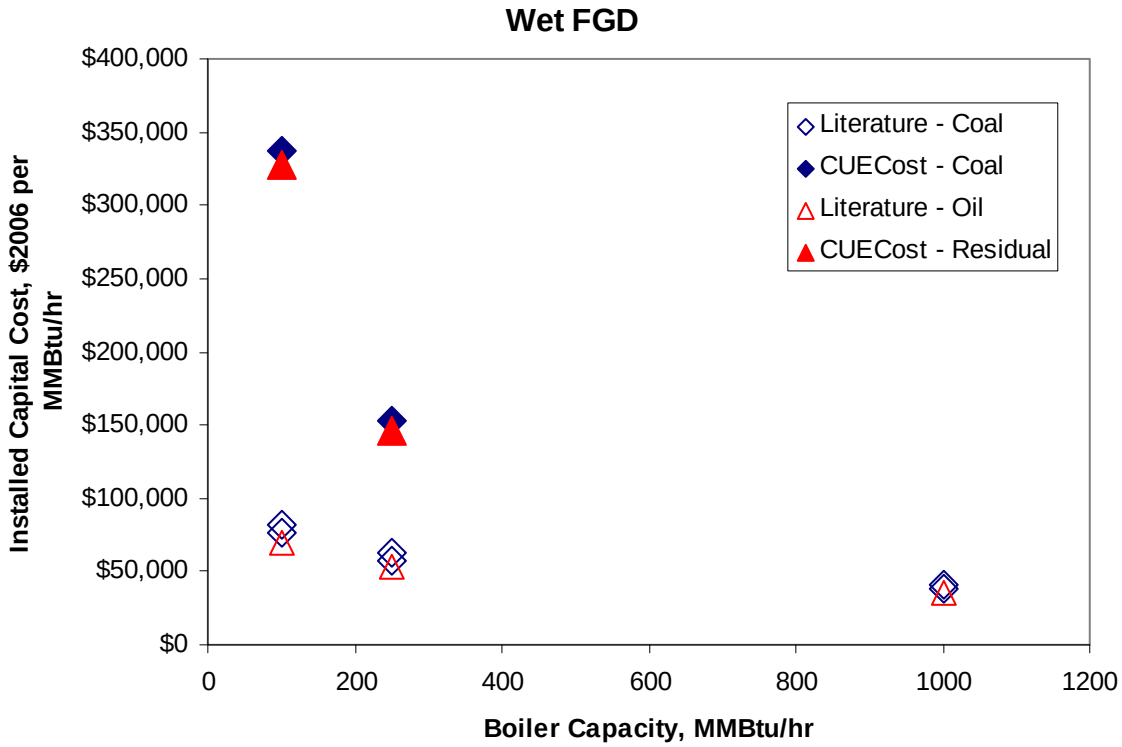


Figure 5-5. Comparison of CUECost-ICI model and reported literature values for capital cost of wet FGD for SO_2 control

Literature values for capital costs for PM control were evaluated from EPA reports on PM controls applied to ICI boilers [US EPA, 2003a; US EPA, 2003b]. In these references, the capital costs were given in terms of dollars/scfm (2002$). These costs were converted to dollars per MMBtu/hr using the flow rates in *Table 5-3* and then converted to 2006 dollars, using the Chemical Engineering Plant Cost Index values. Chapter Four contains a detailed discussion of the literature values for PM control costs.

The dry ESP control costs computed with CUECost-ICI were consistent with the literature values, although the CUECost-ICI predicted slightly higher values than reported by EPA for dry, wire-plate ESPs [US EPA, 2003a]. Note that a size was not given in the EPA cost-estimate. The FF costs computed with CUECost-ICI were higher than the literature values for pulse-jet fabric filters [US EPA 2003b].

5.3 Summary

An existing EPA model for estimating costs of selected control technology for NOx, SO_2, and PM for coal-fired EGU boilers greater than 1,000 MMBtu/hr was adapted for ICI boilers. Inputs were modified to allow a wider variety of fuels and to express boiler capacity in MMBtu/hr instead of MW. Modification of the correlations used for the coal-fired EGU model to calculate capital and operating costs for ICI boilers was outside the scope of this work. The new model, CUECost-ICI provided good agreement with published values of capital cost of APCD equipment for small boiler sizes for coal-, oil- and natural gas-fueled boilers. The resulting model provided a quick and flexible means to estimate capital and operating costs of

specific control technologies as applied to ICI boilers. Further detailed and extensive work will be needed to validate and refine the model's calculation framework for ICI boilers, and to add other APCD technologies to the model.

5.4 Chapter 5 References

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US EPA. *Air Pollution Control Technology Fact Sheet: Dry Electrostatic Precipitator (ESP) - Wire-Plate Type*; EPA-452/F-03-028, July 15, 2003a. http://www.epa.gov/ttn/catc/dir1/fdespwpl.pdf.

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Whiteman, C. ICAC, "Selective Non-Catalytic Reduction Technology Costs for Industrial Sources," memo to Christopher Recchia, Executive Director, Ozone Transport Commission, October 6, 2006.

6 SUMMARY

ICI boilers are a significant source of NO_x, SO_2, and PM emissions, and are relatively uncontrolled, compared to EGUs. More than half of the surveyed ICI boilers in the Northeast have no controls, approximately one-third have PM controls, very few units have NOx controls, and no units have SO_2 controls.

There are a range of technology options for cost-effectively reducing emissions of NOx, SO_2, and PM emissions from ICI boilers in the U.S. Operating costs may differ for ICI boilers than utility boilers, primarily because of their size and location. ICI boiler sites typically have higher contingency, general facility, engineering, and maintenance costs as a percentage of total capital cost than do utility boilers. While ICI boilers often have cost constraints due to their sizes and diversity of plant layout and settings, these factors also provide opportunities for low-cost applications. It is critical to conduct site-specific suitability analyses to assess performance potential or retrofit feasibility, and match the appropriate emission control technology for specific applications given boiler size, fuel type/quality, duty-cycle, and design characteristics.

This study adapted the CUECost model -- initially developed by EPA to estimate costs of selected control technology for NOx, SO_2, and PM for large coal-fired EGU boilers -- to assess ICI boiler control costs. The modeling results were consistent with published values of capital cost of APCD equipment for small boiler sizes for coal-, oil- and natural gas-fueled boilers.

6.1 NOx Controls

Most of the commercially available NOx control technologies used extensively in EGUs may also apply to ICI boilers. Some technologies have potential to capture mercury from the flue gas. Employing a combination of technologies can be more effective in reducing emissions than a stand-alone technology. While most of these technologies can be used together, some combinations may be more cost-effective. This should be assessed on a site- and strategy-specific basis. Options include:

- *Boiler Tuning or Optimization*, which can yield reductions of five to 15 percent or more;
- *Low-NOx Burner (LNB) and Overfire Air (OFA)*, which can be used separately or as a system, and can reduce NOx emissions by 40 to 60 percent. LNBs are applicable to most ICI boiler types, and are being increasingly used at ICI boilers less than 10 MMBtu/hr. These technologies require site-specific suitability analyses, as several important parameters can have substantial impact on their performance or even retrofit feasibility.
- *Ultra Low-NOx Burners (ULNB)*, which can achieve NOx emission levels on the order of single digits in ppm.
- *Reburn*, which has been used only in large EGU applications, but is an option for larger watertube-type boilers, including stokers. It requires appropriate technical and economic analyses to determine suitability. Reburn may yield 35 to 60 percent reductions in NOx emissions.
- *Selective Catalytic Reduction (SCR)*, which can achieve reductions higher than 90 percent.

- *Selective Non-Catalytic Reduction* (*SNCR),* which can achieve between a 30 to 60 percent reduction in NOx.
- *Regenerative Selective Catalytic Reduction (RSCR^{TM}),* which is able to reduce NOx by 60 to 75 percent and CO by about 50 percent. These systems allow efficient use of an SCR downstream of a particulate control device, where the flue gas typically has a lower temperature than what is required for a conventional SCR. Such conditions are encountered in some ICI boilers firing a variety of fuels, including biomass.

NOx control technologies involving combustion modification have essentially no impact on the CO_2 emissions of the host boilers, with the exception of reburn. SNCR and SCR impose some degree of energy demand on the host boiler, including pressure, compressor, vaporization, and steam losses.

Most estimates for ICI boilers indicate capital costs in the range of $1,000 to $6,000 per MMBtu/hr and $1,000 to $7,000 per ton of NOx removed. LNBs and SNCR costs range from $1,000 to $3,000 per ton. For SCR, costs are between $2,000 and $14,000 per ton. SCR and SNCR costs are driven primarily by the consumption of the chemical reagent.

6.2 SO_2 Controls

ICI boilers firing coal are good candidates for employing SO_2 control technologies. Options include:

- *Flue Gas Desulfurization (FGD) or Scrubbers.* These technologies are commercially available, and have been used extensively on EGUs since the 1970s. *Wet scrubbers* (Wet FGD) are the predominant SO_2 control technology currently in use for EGUs, and are typically associated with high-sulfur applications. *Dry scrubbers* include Spray Dryers (SD) and Dry Sorbent Injection (DSI) technologies, and are more compatible with low- to medium-sulfur coals. Some dry scrubber systems can remove 20 to 60 percent of the SO_2, and in some cases up to 90 to 99 percent for HCl and SO_3. DSI technologies are currently being demonstrated on ICI boilers. Furnace Sorbent Injection systems used on cement plants are capable of SO_2 reductions of up to 90 percent for industrial applications and ICI boilers, as well as HCl and HF reductions of greater than 95 percent. For SDs, cost per ton of SO_2 removed was in the range of $1,600 to $5,000. Costs were between $1,900 and $3,800 per ton of SO_2 for wet FGDs. While the SO_2 capital costs computed with CUECost for SDs were consistent with the literature at 250 MMBtu/hr, the capital costs computed for wet FGDs were high compared to values reported in the literature.
- *Fuel switching*. While not a control technology *per se*, the emission reduction benefits of fuel switching are directly proportional to the difference in sulfur contents of the fuels. Fuel switching requires considerable cost and operational analyses. In the NESCAUM region, residual oil is commonly used in ICI boilers. Switching from a 3 to a 1 percent sulfur residual oil can provide cost-effective SO_2 reductions at about $771 per ton of SO_2 removed. For oil-fired ICI boilers, switching to lower-sulfur oil can provide significant reductions in emissions of SO_2, as well as in $PM_{2.5}$. The cost of switching to distillate oil is estimated to be much higher than for residual oil, because the higher cost of distillate oil.

6.3 PM Controls

ICI boilers burn a variety of fuels that contain fly ash and thus emit PM. PM control technologies have been commercially available and widely used in EGU boilers for many years. While PM controls are not currently widely used on ICI boilers, there are no technical reasons why PM controls cannot be applied to solid-fueled and oil-fired boilers. They are very effective in removing total PM and $PM_{2.5}$, with most options removing greater than 99 percent. The options include: (1) *fabric filters or baghouses*; (2) *wet and dry electrostatic precipitators (ESPs)*; (3) *venturi scrubbers*; (4) *cyclones*; and (5) *core separators*. Control technology decisions should be made on a case-by-case basis that accounts for technical, economic, and regulatory considerations. Fabric filters are not suitable for fuel oil applications due to the "stickiness" and composition of the ash. The cost effectiveness of baghouses was in the range of $50 to $1,000 per ton of PM removed for coal and up to $15,000 per ton of PM removed for oil. The cost effectiveness of ESPs was in the range of $50 to $500 per ton of PM for coal, and up to $20,000 per ton of PM for oil. PM control technologies will result in some parasitic energy loss due to pressure loss, power consumption, and ash handling. Dry ESPs and fabric filters have the lowest associated parasitic power consumption (<2 kW/1000 acfm), while high-energy venturi scrubbers can have a larger parasitic consumption – up to 10 kW/1000 acfm or higher.

APPENDIX A: Survey of Title V Permits in NESCAUM Region

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Solutia Incorporated	MA	Foster Wheeler	249	Coal (Bit. 0.7%S)	-	0.027	baghouse (Carborundum Environmental Systems)	1.2	-	0.525	OFA (Foster wheeler)	-
St. Gobain Abrasives	MA	Riley	230	Coal (Subbit. 0.63%S)	-	0.1	Dust Collector	1.1	-	0.45	LNB	-
UMASS Amherst	MA	Union Iron Works	80	Coal	-	0.12	baghouse	1.1	-	0.43	-	Convert to CHP No. 2 (9/07)
Cooley Dickinson Hospital	MA	Early 1980s	-	Wood	-	-	-	0.008	-	0.16	-	-
Cooley Dickinson Hospital	MA	2006/ AFS Energy Systems	29.88	Wood	-	0.01	Cyclone, Baghouse	0.025	-	0.15	FGR	-
Seaman Paper	MA	2006/ Hurst Boiler	29.88	Wood	-	0.01	Baghouse	0.025	-	0.15	FGR	-

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	**State**	**Year/ Manuf.**	**Heat Input (MMBtu/hr)**	**primary fuel**	**secondary fuel**	**limit (lb/MMBtu)**	**control device**	**limit (lb/MMBtu)**	**control device**	**limit (lb/MMBtu)**	**control device**	**Comments**
Cornell University	NY	-	248	Coal	-	0.3	Fabric Filter	Coal 1% S by weight	-	0.4	-	
Cornell University	NY	-	117	Coal	-	0.35	Fabric Filter	Coal 1% S by weight	-	0.4	-	-
Commonwealth Plywood	NY	-	16	Wood	-	-	Multi-Cyclone w/o Fly ash injection	-	-	-	-	-
Crawford Furniture	NY	-	6	Wood	-	-	Single Cyclone	-	-	-	-	-
Deferiet Paper Company	NY	1945/ Combustion Engineering	190	Coal	-	0.46	Multi-Cyclone w/o Fly ash injection, and wet Venturi scrubber	2.5	-	0.5	-	-
Eastman Kodak	NY	-	265	Coal (Bit.)	-	0.26	ESP	2.5 (coal)	-	0.53	-	Boiler # 13

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Eastman Kodak	NY	-	265	Coal (Bit.)	-	0.26	ESP	2.5 (coal)	-	0.53	-	Boiler # 14
Eastman Kodak	NY	-	478	Coal (Bit.)	#2 Oil	0.26	ESP	-	-	-	-	Boiler # 15
Eastman Kodak	NY	-	500	Coal (Bit.)	#2 Oil	-	ESP	-	-	0.6	-	Boiler # 41
Eastman Kodak	NY	-	500	Coal (Bit.)	#2 Oil	-	ESP	-	-	0.6	-	Boiler # 42
Eastman Kodak	NY	-	640	Coal (Bit.)	#2 Oil	-	ESP	-	-	0.6	-	Boiler # 43
Eastman Kodak	NY	-	705	Coal (Bit.)	#2 Oil	0.035	ESP	.6 (coal)	-	0.42	-	Boiler # 44

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Gunlocke Co.	NY	E. Keeler	18	Wood	Oil #2	0.53	Fly Ash Cyclone	-	-	-	-	
Harden Furniture	NY	Industrial Boiler Co.	14.6	Wood	-	-	Multi-Cyclone w/ Fly ash injection	-	-	-	-	
Harden Furniture	NY	Industrial Boiler Co.	41.54	Wood	-	-	Multi-Cyclone w/ Fly ash injection	-	-	-	-	
Harden Furniture	NY	Industrial Boiler Co.	27.6	Wood	-	-	Multi-Cyclone w/ Fly ash injection	-	-	-	-	
Lyonsdale Biomass	NY	Zurn	290	Wood	-	0.1	-	-	-	0.2	-	
Morton International	NY	-	138	Coal	-	0.34	Fabric Filter, ESP	1.7	-	0.5	-	

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
SUNY at Binghamton	NY	International Boiler Works	100	Coal	Coal/Wood Mix	0.6	Multi-Cyclone w/o Fly ash injection	1.7	-	-	-	X3
SUNY at Binghamton	NY	International Boiler Works	50	Coal	Coal/Wood Mix	0.6	Multi-Cyclone w/o Fly ash injection	1.7	-	-	-	
US Salt - Watkins Glen Refinery	NY	2000?	160	Coal and/or Wood	NG and/or Coal, Wood	0.051	Fabric Filter	1.2	-	0.18	SNCR	
Dirigo Paper	VT	1977	180	Wood	-	0.20 gr/dscf	multiclone	-	-	0.3	none	-
Ethan Allen	VT	1950	59.5	Wood	-	0.45 gr/dscf	multiclone	-	-	1.94lb/ton wet wood 7.45lb/ton dry wood	none	-
Fraser	NH	1981, Zurn	324	Wood/Bark/Paper	# 6 Oil	0.1	Multi-cyclone + Venturi scrubber	0.8	-	0.25	-	

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Tillotson Rubber	NH	1978	41	Wood	-	0.43	Multi-cyclone	-	-	-	-	
Allen Rogers Limited	NH		5	Wood								
Allen Rogers Limited	NH		5	Wood								
Forest Products Processing Center	NH		47	Wood								
Madison Lumber Mill	NH		13	Wood								
Chick Packaging	NH		10	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Ossipee Mountain Land Company	NH		4	Wood								
Ossipee Mountain Land Company	NH		4	Wood								
Tommila Brothers	NH		11	Wood								
Monadnock Forest Products	NH		30	Wood								
Whitney Brothers Company	NH		2	Wood								
HG Wood Industries	NH		9	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Design Contempo	NH		19	Wood								
Design Contempo	NH		13	Wood								
Solon Manufacturing	NH		9	Wood								
Rochester Shoe Tree/Ashland	NH		4	Wood								
Precision Lumber	NH		9	Wood								
King Forest Industries - Wentworth	NH		29	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Peterboro Basket Company	NH		3	Wood								
Souhegan Wood Products	NH		8	Wood								
Souhegan Wood Products	NH		1	Wood								
Souhegan Wood Products	NH		1	Wood								
Concord Steam Corporation	NH		40	Wood								
Concord Steam Corporation	NH		40	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Boyce Highlands	NH		4	Wood								
Herrick Millwork	NH		5	Wood								
Northland Forest Products	NH		5	Wood								
Anthony Galluzzo Corporation	NH		4	Wood								
Cousineau Wood Products	NH		14	Wood								
Newport Mills Inc	NH		6	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Newport Mills Inc	NH		6	Wood								
Catamount Pellet Corporation	NH		40	Wood								
Durgin & Crowell Lumber Company	NH		10	Wood								
GH Evarts & Company	NH		7	Wood								

References: State Title V Permits, Coal SO_2 Database, ICI Coal Database, MA ICI 100-250 Boiler Database, VT ICI Boiler Database

APPENDIX B: CUECost-ICI Inputs

INPUTS

Description	Units	Input 1	Input 2	Input 3	Input 4	Input 5
General Plant Technical Inputs						
Location - State	Abbrev.	PA	PA	PA	PA	PA
Combustion Configuration	Abbrev.	PC	PC	PC	PC	PC
MW Equivalent of Flue Gas to Control System	MW	25	25.1	28.6	28.6	32.9
Net Plant Heat Rate	Btu/kWhr	10,000	11,370	8,750	8,750	7,600
Plant Capacity Factor	%	66%	66%	66%	66%	66%
Total Air Downstream of Economizer	%	154%	169%	118%	118%	119%
Air Heater Leakage	%	12%	12%	12%	12%	12%
Air Heater Outlet Gas Temperature	°F	350	350	350	350	350
Inlet Air Temperature	°F	80	80	80	80	80
Ambient Absolute Pressure	In. of Hg	29.4	29.4	29.4	29.4	29.4
Pressure After Air Heater	In. of H2O	-12	-12	-12	-12	-12
Moisture in Air	lb/lb dry air	0.013	0.013	0.013	0.013	0.013
Ash Split:						
Fly Ash	%	85%	85%	85%	85%	85%
Bottom Ash	%	15%	15%	15%	15%	15%
Seismic Zone	Integer	1.0	1.0	1.0	1.0	1.0
Retrofit Factor	Integer	1.0	1.0	1.0	1.0	1.0
(1.0 = new, 1.3 = medium, 1.6 = difficult)						
Select Coal	Integer	2	3	4	5	6
Is Selected Coal a Powder River Basin Coal?	Yes / No	No	No	No	No	No
Economic Inputs						
Cost Basis -Year Dollars	Year	2006	2006	2006	2006	2006
Service Life (levelization period)	Years	15	15	15	15	15
Inflation Rate	%	3%	3%	3%	3%	3%
After Tax Discount Rate (current $'s)	%	8%	8%	8%	8%	8%
AFDC Rate (current $'s)	%	8%	8%	8%	8%	8%
First-year Carrying Charge (current $'s)	%	22%	22%	22%	22%	22%
Levelized Carrying Charge (current $'s)	%	17%	17%	17%	17%	17%
First-year Carrying Charge (constant $'s)	%	16%	16%	16%	16%	16%
Levelized Carrying Charge (constant $'s)	%	12%	12%	12%	12%	12%
Sales Tax	%	6%	6%	6%	6%	6%
Escalation Rates:						
Consumables (O&M)	%	3%	3%	3%	3%	3%
Capital Costs:						
Is Chem. Eng. Cost Index available?	Yes / No	Yes	Yes	Yes	Yes	Yes
If "Yes" input cost basis CE Plant Index.	Integer	478.7	478.7	478.7	478.7	478.7
If "No" input escalation rate.	%	3%	3%	3%	3%	3%
Construction Labor Rate	$/hr	$35	$35	$35	$35	$35
Prime Contractor's Markup	%	3%	3%	3%	3%	3%

Operating Labor Rate	$/hr	$25	$25	$25	$25	$25
Power Cost	Mills/kWh	47	47	47	47	47
Steam Cost	$/1000 lbs	3.5	3.5	3.5	3.5	3.5

Limestone Forced Oxidation (LSFO) Inputs

SO_2 Removal Required	%	95%	95%	95%	95%	95%
L/G Ratio	gal / 1000 acf	125	125	125	125	125
Design Scrubber with Dibasic Acid Addition?	Integer	2	2	2	2	2
(1 = yes, 2 = no)						
Adiabatic Saturation Temperature	°F	127	127	127	127	127
Reagent Feed Ratio	Factor	1.05	1.05	1.05	1.05	1.05
(Mole CaCO3 / Mole SO_2 removed)						
Scrubber Slurry Solids Concentration	Wt. %	15%	15%	15%	15%	15%
Stacking, Landfill, Wallboard	Integer	1	1	1	1	1
(1 = stacking, 2 = landfill, 3 = wallboard)						
Number of Absorbers	Integer	1	1	1	1	1
(Max. Capacity = 700 MW per absorber)						
Absorber Material	Integer	1	1	1	1	1
(1 = alloy, 2 = RLCS)						
Absorber Pressure Drop	in. H2O	6	6	6	6	6
Reheat Required ?	Integer	1	1	1	1	1
(1 = yes, 2 = no)						
Amount of Reheat	°F	25	25	25	25	25
Reagent Bulk Storage	Days	60	60	60	60	60
Reagent Cost (delivered)	$/ton	$15	$15	$15	$15	$15
Landfill Disposal Cost	$/ton	$25	$25	$25	$25	$25
Stacking Disposal Cost	$/ton	$6	$6	$6	$6	$6
Credit for Gypsum Byproduct	$/ton	$2	$2	$2	$2	$2
Maintenance Factors by Area (% of Installed Cost)						
Reagent Feed	%	5%	5%	5%	5%	5%
SO_2 Removal	%	5%	5%	5%	5%	5%
Flue Gas Handling	%	5%	5%	5%	5%	5%
Waste / Byproduct	%	5%	5%	5%	5%	5%
Support Equipment	%	5%	5%	5%	5%	5%
Contingency by Area (% of Installed Cost)						
Reagent Feed	%	20%	20%	20%	20%	20%
SO_2 Removal	%	20%	20%	20%	20%	20%
Flue Gas Handling	%	20%	20%	20%	20%	20%
Waste / Byproduct	%	20%	20%	20%	20%	20%
Support Equipment	%	20%	20%	20%	20%	20%
General Facilities by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	10%	10%	10%
SO_2 Removal	%	10%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	10%	10%	10%
SO_2 Removal	%	10%	10%	10%	10%	10%

Flue Gas Handling	%	10%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%	10%

Lime Spray Dryer (LSD) Inputs

SO_2 Removal Required	%	90%	90%	90%	90%	90%
Adiabatic Saturation Temperature	°F	127	127	127	127	127
Flue Gas Approach to Saturation	°F	20	20	20	20	20
Spray Dryer Outlet Temperature	°F	147	147	147	147	147
Reagent Feed Ratio	Factor	0.90	0.90	0.90	0.90	0.90
(Mole CaO / Mole Inlet SO_2)						
Recycle Rate	Factor	30	30	30	30	30
(lb recycle / lb lime feed)						
Recycle Slurry Solids Concentration	Wt. %	35%	35%	35%	35%	35%
Number of Absorbers	Integer	2	2	2	2	2
(Max. Capacity = 300 MW per spray dryer)						
Absorber Material	Integer	1	1	1	1	1
(1 = alloy, 2 = RLCS)						
Spray Dryer Pressure Drop	in. H2O	5	5	5	5	5
Reagent Bulk Storage	Days	60	60	60	60	60
Reagent Cost (delivered)	$/ton	$60	$60	$60	$60	$60
Dry Waste Disposal Cost	$/ton	$25	$25	$25	$25	$25
Maintenance Factors by Area (% of Installed Cost)						
Reagent Feed	%	5%	5%	5%	5%	5%
SO_2 Removal	%	5%	5%	5%	5%	5%
Flue Gas Handling	%	5%	5%	5%	5%	5%
Waste / Byproduct	%	5%	5%	5%	5%	5%
Support Equipment	%	5%	5%	5%	5%	5%
Contingency by Area (% of Installed Cost)						
Reagent Feed	%	20%	20%	20%	20%	20%
SO_2 Removal	%	20%	20%	20%	20%	20%
Flue Gas Handling	%	20%	20%	20%	20%	20%
Waste / Byproduct	%	20%	20%	20%	20%	20%
Support Equipment	%	20%	20%	20%	20%	20%
General Facilities by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	10%	10%	10%
SO_2 Removal	%	10%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	10%	10%	10%
SO_2 Removal	%	10%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%	10%

Particulate Control Inputs

Outlet Particulate Emission Limit	lbs/MMBtu	0.03	0.03	0.01	0.01	0
Fabric Filter:						
Pressure Drop	in. H2O	6	6	6	6	6
Type (1 = Reverse Gas, 2 = Pulse Jet)	Integer	2	2	2	2	2
Gas-to-Cloth Ratio	acfm/ft^2	5.5	5.5	5.5	5.5	5.5
Bag Material (RGFF fiberglass only) (1 = Fiberglass, 2 = Nomex, 3 = Ryton)	Integer	1	1	1	1	1
Bag Diameter	inches	6	6	6	6	6
Bag Length	feet	20	20	20	20	20
Bag Reach		3	3	3	3	3
Compartments Out of Service	%	10%	10%	10%	10%	10%
Bag Life	Years	2	2	2	2	2
Maintenance (% of installed cost)	%	5%	5%	5%	5%	5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	10%	10%	10%	10%	10%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%
ESP:						
Strength of the electric field in the ESP = *E*	kV/cm	10.0	10.0	10.0	10.0	10.0
Plate Spacing	in.	12	12	12	12	12
Plate Height	ft.	36	36	36	36	36
Pressure Drop	in. H2O	3	3	3	3	3
Maintenance (% of installed cost)	%	5%	5%	5%	5%	5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	10%	10%	10%	10%	10%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%

NOx Control Inputs

Selective Catalytic Reduction (SCR) Inputs

NH3/NOx Stoichiometric Ratio	NH3/NOx	0.9	0.9	0.9	0.9	0.9
NOx Reduction Efficiency	Fraction	0.70	0.70	0.70	0.70	0.70
Inlet NOx	lbs/MMBtu	0.6	0.26	0.2	0.4	0.4
Space Velocity (Calculated if zero)	1/hr	3000	3000	11800	11800	16800
Overall Catalyst Life	years	4	4	4	4	4
Ammonia Cost	$/ton	411.17	411.17	411.17	411.17	411.17
Catalyst Cost	$/ft3	356.34	356.34	356.34	356.34	356.34
Solid Waste Disposal Cost	$/ton	25.38	25.38	25.38	25.38	25.38
Maintenance (% of installed cost)	%	1.5%	1.5%	1.5%	1.5%	1.5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	5%	5%	5%	5%	5%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%
Number of Reactors	integer	1	1	1	1	1
Number of Air Preheaters	integer	1	1	1	1	1

Selective NonCatalytic Reduction (SNCR) Inputs

Reagent	1:Urea 2:Ammonia	1	1	1	1	1
Number of Injector Levels	integer	3	3	3	3	3
Number of Injectors	integer	18	18	18	18	18
Number of Lance Levels	integer	0	0	0	0	0
Number of Lances	integer	0	0	0	0	0
Steam or Air Injection for Ammonia	integer	1	1	1	1	1
NOx Reduction Efficiency	Fraction	0.50	0.50	0.50	0.50	0.50
Inlet NOx	lbs/MMBtu	0.6	0.26	0.2	0.4	0.2
NH3/NOx Stoichiometric Ratio	NH3/NOx	1.2	1.2	1.2	1.2	1.2
Urea/NOx Stoichiometric Ratio	Urea/NOx	1.2	1.2	1.2	1.2	1.2
Urea Cost	$/ton	200	200	200	200	200
Ammonia Cost	$/ton	411.17	411.17	411.17	411.17	411.17
Water Cost	$/1,000 gal	0.22	0.22	0.22	0.22	0.22
Maintenance (% of installed cost)	%	1.5%	1.5%	1.5%	1.5%	1.5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	5%	5%	5%	5%	5%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%

Low-NOx Burner Technology Inputs

NOx Reduction Efficiency	fraction	0.40	0.40	0.40	0.40	0.40
Boiler Type	T:T-fired, W:Wall	W	W	W	W	W
Retrofit Difficulty	L:Low, A:Average, H:High	A	A	A	A	A
Maintenance Labor (% of installed cost)	%	0.8%	0.8%	0.8%	0.8%	0.8%
Maintenance Materials (% of installed cost)	%	1.2%	1.2%	1.2%	1.2%	1.2%

Natural Gas Reburning Inputs

NOx Reduction Efficiency	fraction	0.61	0.61	0.61	0.61	0.61
Gas Reburn Fraction	fraction	0.15	0.15	0.15	0.15	0.15
Waste Disposal Cost	$/ton	11.48	11.48	11.48	11.48	11.48
Natural Gas Cost	$/MMBtu	4.24	4.24	4.24	4.24	4.24
Maintenance (% of installed cost)	%	1.5%	1.5%	1.5%	1.5%	1.5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	2%	2%	2%	2%	2%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%



Proposed BACT Alternative

November 19, 2018

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Appendix A (Economic Analysis Spreadsheets – V1)

Appendix B (Economic Analysis Spreadsheets – V2)

Appendix C (Coal Analyses Summary)

Appendix D (Professional Memos)

1.0 Introduction

The Fairbanks North Star Borough (FNSB) has levels of fine particulate matter ($PM_{2.5}$) that are above the health based National Ambient Air Quality Standard (NAAQS). In November 2009 the area was designated as a Moderate Nonattainment Area (NAA) based on monitoring data indicating the area did not meet the 2006 24-hour $PM_{2.5}$ standard. On April 28, 2017, the area was re-designated as a "Serious" NAA as a result of not attaining the $PM_{2.5}$ standard within 5-years from designation. As a result, the state is required to propose additional measures to bring the area into compliance within 10-years from designation (i.e., December 2019).

Once EPA re-classified the FNSB $PM_{2.5}$ nonattainment area to Serious, it triggered the requirement for stationary sources with over 70 tons per year (tpy) potential to emit (PTE) for $PM_{2.5}$ or its precursors (SO_2, NO_x, VOC, & NH_3) to conduct a Best Available Control Technology (BACT) analysis. Based on the Alaska Department of Environmental Conservation (ADEC) preliminary evaluations, sulfur dioxides are being evaluated for point source control measures under BACT. At this time, ADEC is considering one control measure per major stationary source to meet BACT and Most Stringent Measures (MSM) for sulfur dioxide (SO2) control. Preliminary Determinations by ADEC suggest a capital cost to Aurora Energy, LLC (Aurora) for BACT compliance of $12,332,076 for an 80% removal efficiency using dry sorbent injection.

Aurora asserts that the proposed Best Available Control Technologies for sulfur dioxide emissions are not economically feasible. Confronted with this fact, ADEC and the EPA have asked Aurora to suggest an alternative to the ADEC proposed BACT. Within the context of this document Aurora is providing a proposal for alternative BACTs, all of which mitigate Aurora's impact to the nonattainment area problem.

The alternative BACTs proposed by Aurora provide meaningful solutions in offsetting the largest contributing factor to the $PM_{2.5}$ problem in Fairbanks: home heating. The alternative BACTs being proposed by Aurora are more efficient from a dollar per ton of pollutant removed than the ADEC proposed BACT. Aurora strongly believes that these alternatives can have a more positive impact to the air quality issue than the ADEC proposed BACT. Before implementing these alternative BACTs, Aurora needs ADEC and EPA to agree that these alternative BACTs satisfy Aurora's obligations for compliance with the NAA issue and that future controls to address $PM_{2.5}$ in the NAA will not be required.

Additionally, Aurora is making this alternative proposal based on the premise that ADEC and EPA will consider a precursor demonstration to determine the actual contribution of $PM_{2.5}$ by the point sources in the NAA. It has been stated repeatedly that the point sources are not the primary cause of the $PM_{2.5}$ problem. However there has never been a thorough analysis done to understand to what extent the point sources are or are not contributing to the problem. Should a precursor demonstration show that the point sources within the NAA are not major contributors to the $PM_{2.5}$ problem, all $PM_{2.5}$ compliance requirements imposed on the point sources shall be vacated. If however the precursor demonstration shows that the point sources are above the insignificance threshold, the alternative BACTs proposed by Aurora would satisfy the requirements for compliance within the NAA.

In closing, Aurora desires to be a part of the solution to reduce the $PM_{2.5}$ levels within the NAA. Aurora remains convinced that the ADEC proposed BACT is cost prohibitive and an inefficient use of funds. Instead Aurora is proposing alternative BACTs that directly help solve the PM2.5 problem. In proposing these alternatives, Aurora needs ADEC and the EPA to agree to continue to study the source of PM2.5

pollution as well as confirm that these alternative BACTs meet Aurora's compliance with the Clean Air Act for purposes of NAA attainment.

1.1 ADEC BACT Analysis

ADEC provided its review of a BACT analysis for Aurora which included an evaluation of technologies to mitigate emissions of oxides of nitrogen (NOx) and sulfur dioxide (SO_2) emissions, which are precursor pollutants that can form $PM_{2.5}$ in the atmosphere post combustion. The BACT analysis evaluated all available control options for equipment emitting the triggered pollutants and followed a process for selecting the best option based on feasibility, economics, energy, and other impacts. The results of the BACT analysis are reflected in Table 1.

Table 1: Department Economic Analysis for Technically Feasible NOx and SO_2 controls.

Technology	Pollutant	Capital Cost ($)	Annualized Cost ($/year)	Cost Effectiveness ($/ton)
Selective Non-Catalytic Reduction (SNCR)[1]	NOx	$ 3,930,809.00	$ 957,728.00	$ 2,226.00
Selective Catalytic Reduction (SCR)[1]	NOx	$ 17,331,770.00	$ 2,787,995.00	$ 3,240.00
Dry Sorbent Injection (DSI)[2]	SO_2	$ 12,332,076.00	$ 4,284,104.00	$ 6,308.00
Spray Dry Absorber (SDA)[2]	SO_2	$ 60,270,115.00	$ 11,862,577.00	$ 15,525.00
Wet Scrubber (WS)[2]	SO_2	$ 65,957,875.00	$ 12,160,961.00	$ 14,469.00

1 - Capital Recovery Factor = 0.094 (7% interest rate for a 20 year equipment life)

2 - Capital Recovery Factor = 0.1098 (7% interest rate for a 15 year equipment life)

1.2 Aurora BACT Analysis

The ADEC requested additional information concerning Aurora's BACT analysis in a letter dated September 13, 2018. One of the ADEC's request were that Aurora comment on the cost analysis spreadsheets developed by ADEC and provided with the Preliminary Draft SIP. Comments were made on the spreadsheets and submitted to the ADEC on November 1, 2018. Below (Table 2) are the results of Aurora's inputs considering EPA and ADEC's comments. Spreadsheets are included along with this proposal for review by the agencies. Several changes to the inputs are documented in the summary for the spreadsheet inputs (See Appendix A & B). In conjunction with the changes made to the spreadsheets, site-specific quote for SO_2 controls, namely Dry Sorbent Injection (DSI), was provided to the ADEC as requested and included as a parameter within the cost analysis spreadsheets for the referenced control technologies. The EPA is requiring that the cost analyses include a 30 year equipment life for the control technologies except SNCR which is evaluated for 20 year equipment life.

Table 2: Adjustment of ADEC Economic Analysis for Technically Feasible NOx and SO_2 Controls – V.1

Technology	Pollutant	Capital Cost ($)	Annualized Cost ($/year)	Cost Effectiveness ($/ton)
Selective Non-Catalytic Reduction (SNCR)[2]	NOx	$ 6,208,948.00	$ 989,197.00	$ 3,107.00
Selective Catalytic Reduction (SCR)[1]	NOx	$ 25,758,941.00	$ 2,921,054.00	$ 4,587.00
Dry Sorbent Injection (DSI)[1]	SO_2	$ 20,682,000.00	$ 4,601,940.00	$ 8,423.00
Spray Dry Absorber (SDA)[1]	SO_2	$ 51,115,267.00	$ 8,716,232.00	$ 12,408.00
Wet Scrubber (WS)[1,3]	SO_2	$ 56,318,290.00	$ 8,839,892.00	$ 11,440.00

1 – Capital Recovery Factor = 0.0669 (5.25% interest rate for a 30 year equipment life) [EPA requirement per comments]

2 – Capital Recovery Factor = 0.0820 (5.25% interest rate for a 20 year equipment life) [EPA requirement per comments]

3 – Does not include costs associated with building and maintaining a wastewater treatment facility. [Notation from ADEC spreadsheet]

Table 3 reflects another iteration (V.2) of Aurora's changes to the ADEC's spreadsheets. The results in Table 3 consider a lower emission rate for both SO_2 and NO_x based on 2011 source testing information and/or additional information. The SO_2 emission rate assumed by the state and Aurora has been 0.39 lbs/MMBtu. The coal analysis for feed coal during the test showed elevated sulfur content (0.18%) in comparison to the 5-year weighted average sulfur content from 2013-2017 (0.14 %). Using a conservative conversion from sulfur content (0.14%) to sulfur dioxide, the 5-year weighted average SO_2 emission rate would be 0.36 lbs/MMBtu. This conservative emission rate was used in the calculations to derive the cost effectiveness values in Table 2. The sulfur content during the source test conducted in 2011 (0.18%) when converted to a heat input emission rate considering total conversion of sulfur to SO_2 yields an emission factor of 0.48 lbs/MMBtu. The actual tested emission rate was 0.40 lbs/MMBtu. The emission rate for SO_2 was 83% of the maximum potential. This suggests there is 17% capture of sulfur compounds in the ash. As such, the emission rate derived and used in Table 3, considers a 17% capture of sulfur in the ash. The conversion of sulfur to SO_2 based on the 5-year weighted average sulfur content in coal and a 17% capture rate yields 0.30 lbs/MMBtu (0.36 lbs/MMBtu X 0.834 = 0.30 lbs/MMBtu). The results in Table 3 account for the current sulfur content in coal and the rate adjustment for sulfur capture fraction from the process based on a source test conducted in 2011.

Also accounted for in Table 3 is a more realistic equipment life expectancy for the facility and control equipment. It is not reasonable to consider a 30 year and 20 year life expectancy for the control equipment and the boilers. Considering the age of the Chena Power Plant, Units 1-3 are 50,000 lb/hr boilers that were installed in the early 1950s, and Unit 5 is a 200,000 lb/hr boiler which was installed in 1970. Units 1-3 are already +65 years and Unit 5 is +45 years old. A 30 year horizon should not be applicable to the Chena Power Plant. A 15 year equipment life is considered in the following cost effectiveness analysis (Table 3).

Table 3: Adjustment of ADEC Economic Analysis for Technically Feasible NOx and SO_2 Controls – V.2

Technology	Pollutant	Capital Cost ($)	Annualized Cost ($/year)	Cost Effectiveness ($/ton)
Selective Non-Catalytic Reduction (SNCR)[1]	NOx	$ 6,208,948.00	$ 1,088,694.00	$ 3,419.00
Selective Catalytic Reduction (SCR)[1]	NOx	$ 25,758,941.00	$ 3,721,132.00	$ 5,844.00
Dry Sorbent Injection (DSI)[1]	SO_2	$ 20,682,000.00	$ 4,914,480.00	$ 10,785.00
Spray Dry Absorber (SDA)[1]	SO_2	$ 50,880,540.00	$ 10,084,456.00	$ 17,213.00
Wet Scrubber (WS)[1,2]	SO_2	$ 56,318,290.00	$ 10,314,589.00	$ 16,005.00

1 – Capital Recovery Factor = 0.0980 (5.25% interest rate for a 15 year equipment life)
2 – Does not include costs associated with building and maintaining a wastewater treatment facility. [Notation from ADEC spreadsheet]

2.0 Economic Infeasibility

The BACT review process as outlined by EPA includes five-step approach to determine the best control option. The economic feasibility of potential measures are addressed under Step 4 of the review process. Since there is no cost threshold for economic feasibility for controls within a serious nonattainment area, a source has to make the assertion to the regulatory agencies in order for economic infeasibility to be considered. Aurora's BACT results, as illustrated in Table 3, show that the least expensive SO_2 control technology is a $20 million dollar investment and the cost effectiveness value is above $10,000/ton of SO_2 removed.

Therefore, per the fine particulate implementation guidance, if a source contends that a source-specific control level should not be established because the source cannot afford the control measure or technology demonstrated to be economically feasible, the source should make its claim known to the state and support the claim with information regarding the impact of imposing the identified control measure or technology on the following financial indicators to the extent applicable:[1]

1. Fixed and variable production costs;
2. Product supply and demand elasticity;
3. Product prices (cost absorption vs. cost pass-through);
4. Expected costs incurred by competitors;
5. Company Profits;
6. Employment costs;
7. Other costs (e.g., for BACM implemented by public sector entities).

At this time, ADEC is considering one control measure per major stationary source to meet BACT and Most Stringent Measures (MSM) for sulfur dioxide (SO_2) control. ADEC's preliminary determination suggests Aurora invest $12,332,076 for DSI technology to remove 80% of the SO_2 emissions from the Chena Power Plant. ADEC estimates that annualized costs for the application would be $4,284,104. ADEC's projected capital cost for retrofit SO_2 control technology is just above half of the costs of a +50/-30 design (e.g., capital cost $20,682,000) which was recently submitted to the ADEC. Even if the lower cost for controls estimated by the ADEC were valid, it is not economically feasible and therefore should not be required. Further, ADEC does not know whether the installation of DSI or any control technology on stationary sources will have a significant impact on the overall air quality in the non-attainment area.

Aurora has one electric customer and approximately 200 district heating customers. Income from power production is from wholesale electric sales to the local electrical cooperative, Golden Valley Electrical Association (GVEA). Aurora has a long term contract with GVEA which would be difficult to renegotiate for necessary price increases to accommodate additional control technologies. Pass-through cost opportunities for Aurora's district heating are not viable. The necessary product price increases to cover additional costs of the proposed control technology would price Aurora out of the market for both heat and power. The result would be higher electric and heat costs, coupled with an increase in $PM_{2.5}$ pollution due to the introduction of ground-level emissions from oil and/or gas fired furnaces and boilers that would be installed to replace uneconomic district heat. As Aurora customers switch to less expensive fossil fuels – or yet even less expensive wood – the resulting burden on Aurora's remaining customers will increase, causing more and more of them to switch, resulting in a continuous increase in particulate emissions in the Fairbanks core, and in a death spiral for Aurora as an economically viable business. Within this section, Aurora will address the financial indicators applicable to demonstrate the economic infeasibility of installing and operating ADEC's proposed control technology.

1. Production Costs

Aurora's five year operating costs for electric and district heating (RCA) are provided below in Table 4. Operating costs consist of operations expense, maintenance expense, administrative expenses, and depreciation expense. The net operating costs for power generation was $0.08/kW in 2017 (Table 4). The

[1] Federal Register, Vol. 81, No.164, Wednesday August 24, 2016. pg. 58085.

margin for income is small as reflected in Table 6. District heating operating costs exceed income generated resulting in a net loss over the past 5 years (Table 6). [2]

Table 4: Aurora Energy Operating Costs

Year	Electrical Total	Net kWh	$/kWh	District heating Total	Net MMBtu	$/MMBtu
2017	$13,795,480	181,113,600	$0.08	$4,658,655	262,189	$17.77
2016	$13,707,259	189,093,610	$0.07	$5,285,399	249,151	$21.21
2015	$12,582,952	194,083,220	$0.06	$5,395,212	267,686	$20.16
2014	$12,250,548	184,058,400	$0.07	$5,648,209	273,089	$20.68
2013	$10,833,349	181,569,600	$0.06	$5,387,853	274,139	$19.65
Average	***$12,633,918***	***185,983,686***	***$0.07***	***$5,275,066***	***265,251***	***$19.89***

2. Supply and Demand Elasticity

The issue of supply and demand elasticity is addressed in more detail within the context of the following sections. The cost of control technologies cannot be absorbed by Aurora under the current pricing to consumers for district heating and power. Aurora has no alternative but to pass those costs to its customers. Those customers, in turn, would have no choice but to go elsewhere for their heat and power, as Aurora would no longer be competitive with other options. This would be the beginning of a death spiral for Aurora as a business, and the beginning of an increase in lower level emissions in the Fairbanks core as more and more buildings switch to oil or gas for heat.

3. Product prices (cost absorption vs cost pass-through)

Aurora's current product prices are competitive with other power suppliers and heating sources. Aurora's heat business is generally regulated by the Regulatory Commission of Alaska (RCA). District heating prices are set based on Aurora's cost to produce the heat. At the same time, many district heat customers are able to switch to alternative sources of heat, such as oil, gas or wood; therefore, Aurora has a powerful incentive to maintain district heating prices competitive with other heating options. Likewise, GVEA maintains several contracts with various power producers including Aurora. GVEA's portfolio includes power generated with natural gas, hydroelectric gradient, wind, solar, coal, and oil. Aurora's contract with GVEA ensures Aurora's power pricing is competitive and marketable.

District Heating

District heating prices cannot absorb the pass through costs of control technology. Aurora's district heating customer base is approximately 200 including mostly commercial and some residential customers. District steam heating rates are set with oversight by the RCA and do not vary. Hot water district heating prices differ depending on consumers' annual heating needs. The hot water district heating rates are adjusted throughout the year to be competitive with other sources of heat.

Absorbing full or partial costs for upgrades or control technologies is not feasible through district heating rate adjustments. The price adjustment necessary to compensate for the current average annual net loss from district heating (Table 6) would be an increase of $3.71/MMBtu representing a 20% increase in heating costs. A 20% increase in district heat prices per unit energy (MMBtu) is not marketable. The potential is a loss of revenue from customers switching to alternative forms of heat which would make

[2] Based on RCA annual filing from 2013-2017.

district heating even less sustainable and exacerbate air quality due to an increase in ground level emissions.

Electric Generation

Aurora's power pricing cannot absorb the pass through cost of control technologies without revising the current contract and becoming less marketable. Aurora sells its power at wholesale price to GVEA, its sole electric customer. Aurora has averaged 186,000 MWh in net sales annually. Pass through of any additional incurred cost would have to be negotiated with GVEA, and would cause an increase in power costs to all customers in GVEA's service area.

Product Pricing for GVEA including Control Technology Costs

ADEC indicates that SO_2 controls are being considered for BACT or Most Stringent Measures (MSM) at this time.[3] ADEC's estimate of the capital investment of the preferred control technology for Aurora is estimated to be $12,332,076 and the annualized cost is estimated to be $4,284,104. The requirement is that BACT must be installed within 4 years of reclassification of an area from a moderate to a serious nonattainment area.[4] The Fairbanks North Star Borough nonattainment area designation change from "Moderate" to "Serious" was effective June 9, 2017.[5] Since the area is now identified as serious, BACT control would have to be in place by June of 2021. Funds for the capital investment would need to be arranged by 2019 to allow for construction and installation of the control equipment. The power purchase agreement with GVEA would need to be renegotiated prior to committing to construction.

Assuming electrical sales would correspond to the 5-year average (185,984 MWh), the weighted average price per MWh at the Chena Power Plant (CPP) would be $85.51.[6] When the annualized cost of operating the preferred control technology is included, the price of power from the CPP increases to $108.55/MWh; a 27% increase in price of power. The average total electric power consumption of sulfur control on Healy Unit #2 is 550.5 kW.[7] Assuming a comparable station service use, SO_2 control on the Chena Power Plant could require an additional 2.6% for station service load.

The SO_2 control technologies being considered (DSI) require the addition of lime, limestone, or sodium bicarbonate to the gas path prior to the baghouse. The amount of unreacted sorbent added to the process could alter the leaching characteristics of metals from coal ash. Recent testing of coal ash from coal blended with 2% by weight limestone, demonstrated elevated metals leaching from coal ash at various pH. Metals leaching in excess of water quality standards could require Aurora to incur additional disposal costs for coal ash. Aurora would either have to build a coal ash landfill, or take the coal ash to the municipal landfill at a cost to Aurora of $90/ton.[8] If additional costs were incurred by Aurora for disposing 20,000 tons of coal ash, then the price per MWh would need to increase to $118.60; which represents a 39% increase in the price of power.

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[3] ADEC. 2018. *Preliminary Draft, Possible Concepts and Potential Approaches for the development of the FNSB NAA Serious SIP*.

[4] Federal Register, Vol. 81, No.164, Wednesday August 24, 2016.

[5] Federal Register, Vol. 82, No.89, Wednesday May 10, 2017.

[6] 2013 Contract Pricing for 2020: $79.37/MWh (≤150,000 MWh) + $112.12/MWh (>150,000 MWh).

[7] Alaska Industrial Development and Export Authority. 1999. Spray Dryer Absorber System Performance Test Report, Healy Clean Coal Project. Healy, AK.

[8] FNSB. 2014. Interior AK Coal Ash. Pg. 42

Table 5: $/kWh Wholesale Pricing for GVEA including Control Technology Costs

	Average kWh/year (2013-2017)	No Controls	SO2 - DSI	SO2 - SDA	SO2 - WS
Annual BACT Operating Cost		$ -	$4,284,104	$11,862,577	$12,160,961
2020 ($/kWh)	185,983,686	$ 0.09	$ 0.11	$ 0.15	$ 0.15
2020 ($/kWh) -2.5% station load (BACT)	181,334,094	$ 0.08	$ 0.11	$ 0.15	$ 0.15
Coal Ash Disposal - Borough Landfill[1]		$ -	$ 0.12	$ 0.16	$ 0.16

1 - Borough Landfill disposal cost based on 20,000 tons of ash; $90/ton (FNSB. 2014). Interior AK Coal Ash. Pg 42.

Aurora's price of power is in competition with other power producers. If the price of power exceeds that of the competition, Aurora would not be as competitive in the energy market. Currently, GVEA will take as much power as Aurora can produce; however, it is likely that GVEA would reduce the amount of power accepted from Aurora if product prices increase above those of the competition.

4. Expected costs incurred by competitors

The FNSB nonattainment area impacts stationary sources within the area. Aurora's main competitors are power producers outside of the nonattainment area. Aurora's competition will not be required to consider BACT or MSM as a new requirement of a nonattainment area. This puts Aurora at a serious economic disadvantage. It is the only private for-profit power producer in the state being subjected to the $PM_{2.5}$ nonattainment area BACT requirements. Table 5 illustrates the price of wholesale power in $/kWh from Aurora. The price of power with controls is $0.11/kWh. When additional disposal requirements are considered as a result of the use of the control technology, the price of Aurora's wholesale power to GVEA is $0.12/kWh.

Aurora's competition for power sales is primarily natural gas generated power; including Anchorage Municipal Light and Power (AMLP), Matanuska Electric Association, Inc. (MEA), and Chugach Electric Association (CEA). Aurora is also in competition with GVEA's fleet including the coal facilities (Healy #1 and Healy #2). The expected increase in price of Aurora's power due to BACT will make its power less marketable. At $0.12/kWh, the price of Aurora's power to GVEA would exceed AMLP ($0.09/kWh), Healy #1 ($0.10/kWh), MEA ($0.10/kWh), and CEA ($0.11/kWh) based on GVEA's cost of power report in 2017[9]. Aurora currently provides 14% of GVEA's power requirements. At current prices, Aurora's power is competitive. An increase in the price of power to $0.11/kWh or $0.12/kWh would likely change that perspective.

5. Company Profits

Net income (loss) for Aurora over the past five years are not sufficient to absorb annual control technology costs for any of the control technologies proposed. Table 6 below includes the net income (loss) from district heating, electrical generation and the combined company income (loss) for years 2013

[9] 2017 GVEA Annual Report to the RCA.

through 2017. Net income (loss) include income generated from district heat and power sales minus the operating costs as presented in Table 2 and include nonutility income, interest income, miscellaneous amortizations, and interest expenses.

Table 6: Aurora Energy, LLC – 5 Year Net Income (Losses)

Year	Electric	District Heating	Net Income (loss)
2017	$ 801,037.00	$ (377,585.00)	$ 423,452.00
2016	$ 419,092.50	$ (1,808,914.00)	$ (1,389,821.50)
2015	$ 1,094,599.25	$ (1,059,348.00)	$ 35,251.25
2014	$ 321,876.05	$ (892,950.00)	$ (571,073.95)
2013	$ 420,072.77	$ (775,432.00)	$ (355,359.23)
Average	***$ 611,335.51***	***$ (982,845.80)***	***$ (371,510.29)***

The annual cost to operate the preferred technology is $4,284,104 (Table 1 & 4); the average 5-year net income (loss) for Aurora is ($371,510) [Table 6]. Conclusively, Aurora is not able to absorb the cost of additional control technologies.

The only alternative for Aurora to address annual operating expenses for any proposed control technologies would be to attempt to renegotiate the power contract to raise the price of power to GVEA. However, the rate adjustment would increase the price of Aurora's power to the extent that it would be less competitive.

6. Employment Cost

The state's calculations for annual operation costs of the proposed technologies include labor cost increases. The increases vary depending on the type of control technology. As a part of the state's analysis for SO_2 controls, annualized cost increases include the projection of additional labor for operation, maintenance, and administration.

7. Other Costs

No additional costs were considered.

ADEC has not shown that Aurora's, nor other stationary source's, SO_2 emissions are a significant contributor to the nonattainment area problem. ADEC does not know whether installation of BACT or MSM on stationary sources will significantly mitigate the impact of SO_2 on particulate concentration. Aurora cannot afford the control measure or technology that has been selected by the ADEC in the preliminary BACT analyses. The basis for this determination is that Aurora has consistently shown insufficient income to absorb the cost of the control technologies. Alternatively, increasing the price of power or heat to accommodate the cost of control technology will price Aurora's products out of the market. Any increase in district heating prices would make alternative sources of heat more attractive to consumers. The result would be a loss in business from customers switching to alternate sources of heat. This change in heating source could exacerbate pollution emissions at the ground level due to customers' use of distributed home heating alternatives. Aurora's district heating displaces the emissions from the equivalent of 2 – 2.5 million gallons of heating oil. The current power purchase agreement with GVEA allows Aurora's power to be competitive with other power sellers. The cost of additional control technology would have to be negotiated with Aurora's one customer based on its power purchase agreement and make Aurora's power prices less competitive; and subsequently, less sustainable.

3.0 Proposed Alternative BACT – District Heating

Aurora is sympathetic to the requirements of the Serious Nonattainment Area and believe that a reasonable alternative exists within the framework of what is economically feasible. As previously discussed, Aurora asserts that imposing retrofit controls, as proposed by ADEC, on its older boilers in the next four years is economically infeasible and could have negative impacts on the goals of the community to achieve attainment with the $PM_{2.5}$ standard. As such, Aurora has developed a list of mitigating measures that are more economically sustainable and will have a direct impact on the community with respect to achieving attainment with the $PM_{2.5}$ standard. Included as alternatives are the expansion of district heating, a wood drying kiln, and the potential use of biomass.

3.1 District Heating

Aurora is proposing that past district heat expansions as well as future district heating projects be considered as BACT for the Chena Power Plant. As it stands, Aurora's district heating displaces about 42 tons of SO_2 and 2 tons of particulates annually. District heating is referenced in both the Moderate Area State Implementation Plan (SIP)[10] and the Preliminary Serious Area SIP[11] as a Pollution Control Measure for the FNSB NAA. As stated in the Moderate Area SIP, "An increase in the coverage of the district heating systems would therefore result in a decrease in measured $PM_{2.5}$ concentrations". Based on modeling results, the $PM_{2.5}$ concentration attributed to Aurora during an episode in 2008 was 0.02 µg/m^3 and the SO_2 concentration at ground level from Aurora represents 0.75 µg/m^3 (See Table 7).[12] The implication of the small pollutant contribution from Aurora at ground level is that taller stacks decrease the impact from emissions at ground level. The amount of pollutant loading at ground level within the nonattainment area is mitigated by district heating through the removal of ground level source emissions and vertically displacing them. An added benefit to increasing district heat coverage is an increase in efficiency at the plant. The plant is generally base loaded and driven to operate at a maximum capacity; there is moderate room for growth, but realistically, the plant is nearing its maximum capacity. The plant could accommodate, roughly, an additional 100 MMBtu/hour of heating capacity while still being able to provide a modest amount of electricity.

Table 7: Summary of Six Major Fairbanks Point Source Plumes from CALPUFF for the Episode (Jan.23rd to Feb. 9th, 2008) Average Surface Concentrations at the State Office Building of PM2.5 and SO2 in ug/m3.

Power Plant	Episode average SO_2 (µg/m^3)	Episode average $PM_{2.5}$ (µg/m^3)
UAF- 316	2.75	0.16
Aurora- 315	0.75	0.02
Zehnder-109	0.48	0.19
Flint Hills-071	0.016	0.38
GVEA NP-110	3.8	1.45
Ft. WW- 1121	14	1.6
Total surface concentration	21.8	3.8

In order to quantify the impact district heating has on the nonattainment area, Aurora evaluates the potential use of fuel oil based on

[10] ADEC. 2014. *Moderate Area State Implementation Plan. Appendix III.D.5.7.* pg 42.
[11] ADEC. 2018. *Preliminary Draft, Possible Concepts and Potential Approaches for the development of the FNSB NAA Serious SIP*.
[12] ADEC. 2014. Moderate Area State Implementation Plan. Section III.D.5.8-11.

a conversion from the heating load compensated by the plant for district heating. A fuel oil heating value of 137,000 btu/gal and an assumed efficiency of 85% for heating appliances are used to determine the quantity of heating oil equivalent to the district heating load. Since SO_2 and $PM_{2.5}$ are the pollutants of most concern, Aurora is using emission rates for fuel oil using EPA's emission inventory warehouse, AP-42. Using the value of 2566 ppm sulfur in heating oil[13], an emission rate of 36.92 lbs/10^3 gallons ($2.64x10^{-1}$ lbs/MMBtu) for SO_2 emissions and 0.4 lbs/10^3 gallons ($2.86\ x10^{-3}$ lbs/MMBtu) for filterable or direct $PM_{2.5}$ and 1.3 lbs/10^3 gallons ($9.29\ x10^{-3}$ lbs/MMBtu) for condensable $PM_{2.5}$ are derived. Using these emission rates, Aurora can evaluate the impact of district heating on the removal of SO_2 and $PM_{2.5}$ from the nonattainment area.

As part of a further analysis, the SO_2 is converted to $PM_{2.5}$ by using an ADEC derived method for comparing direct emissions of pollutants to $PM_{2.5}$ concentration from various sources. Using this methodology, point source SO_2 emissions, wood smoke emissions, and heating oil SO_2 can be correlated to $PM_{2.5}$ concentration. Through the use of a dispersion model, CALPUFF, ADEC determined that 22% of modeled SO_2 concentration are from point sources at ground level, 78% are from central oil, and <1% from mobile sources. Using this information and the ADEC's methodology (based on 'scenario 2'), a ratio of 5.5 tons SO2 emissions from major sources is estimated to form 1 $\mu g/m^3$ of $PM_{2.5}$ as ammonium sulfate [8.38 TPD/(1.1 $\mu g/m^3$ x 132g/mol of ammonium sulfate/96 g/mol sulfate)]. Likewise, a ratio of 0.3 tons of wood smoke emissions is estimated to form 1 $\mu g/m^3$ of $PM_{2.5}$.[14] Based on the same methodology, the ratio of SO_2 from fuel oil (78% of modeled concentration) to particulates is 0.8 tons of fuel oil SO_2 emissions to 1 $\mu g/m^3$ of $PM_{2.5}$ as ammonium sulfate [4.12 TPD[15]/(3.9 $\mu g/m^3$ x 132g/mol of ammonium sulfate/96 g/mol sulfate)]. To summarize this information and that in Table 8, wood smoke produces 18 times more $PM_{2.5}$ than the SO_2 from point sources and 2.6 times more $PM_{2.5}$ than fuel oil.

Table 8: Source pollutant emission and equivalent contribution in $\mu g/m^3$ of $PM_{2.5}$.

Pollutant	Point Sources (SO_2)	Fuel Oil (SO_2)	Wood Smoke
Emissions (tons)	5.5	0.8	0.3
$PM_{2.5}$ Equivalent Concentration ($\mu g/m^3$)	1	1	1

3.2 District Heat Expansion

District heating from Aurora mitigates emissions from ground level sources. The 5-year average (2013-2017) heating value of Aurora's district heat supply is 265,251 mmbtu/year. That is equivalent to about 2.3 million gallons of heating oil per year; assuming a heating value of 137,000 btu/gal and an 85% efficiency for an oil fired furnace. Using these values, district heat displaces about 42 tons of SO_2 from ground level emissions per year and 2 tons of $PM_{2.5}$ in the down town area. Since 2008, Aurora has added district heating equivalent to 243,000 gallons of fuel oil per year. The impact of the addition is equivalent to the removal of 3510 lbs of wood smoke per year based on SO_2 reduction from fuel oil [4.5 TPY SO_2 fuel oil/0.77 tons SO2 fuel oil/1 $\mu g/m^3$ x 0.3 tons wood smoke/1 $\mu g/m^3$ x 2000 lbs/ton]. District heating records show that 67% of heating use is between November – March (151 days). The loading that

[13] ADEC. 2014. Moderate Area State Implementation Plan. Appendix III.D.5.6. pg 102.
[14] ADEC. 2014. Moderate Area State Implementation Plan. Appendix III.D.5.7. pg 132.
[15] ADEC. 2014. Moderate Area State Implementation Plan. Appendix III.D.5.6. pg 27.

was mitigated since 2008 is approximately 16 lbs/day of wood smoke equivalence during the winter months.

Aurora has the mechanical potential to expand district heating another 100 mmbtu/hr of additional heating. The equivalent SO_2 removal potential would be about 24 tons per year based on the displacement of 1.3 million gallons of heating oil No.2 (fuel oil S% = 0.26).

3.3 District Heating Economics

Installation of district heating can be costly. The evaluation of DH as a control technology for the plant is difficult to assess a cost/ton comparison. Ideally, the expansion cost would be mitigated by revenue generated from the use of district heating. The business model for district heating would justify the expansion; the added benefit would be the reduction in pollutants emissions from ground level sources, and a decrease in the output based emission rate. In general, efficiency gains at the plant is a sustainable practice with the benefit of reducing pollutant emissions at ground level.

3.4 Output Based Emission

District heat expansion has the added benefit of making the plant more efficient. A method of illustrating efficiency gains with respect to pollutant emissions is in the derivation of an output based emission rate. The output based emission rate for SO_2 at the plant is approximately 4.6 lbs/MW of energy output. The emission rate is based on a conservative calculation using the 5-year weighted average coal sulfur content and converting all of it to SO_2. The denominator consists of net power and net district heat sales in MW. When the maximum output of district heating is added to the denominator, the emission rate is reduced to 3.4 lbs/MW. This represents a 27% reduction in the emission rate per energy output.

The output based emission rate can be used to show efficiency gains with respect to pollutant emissions. Efficiency gains through the use of central heat and power facilities clearly demonstrate the advantages of minimize emission increases while maximizing energy output.

4.0 Proposed Alternative BACT - Firewood Drying Kiln

Couched within the benefits of district heating, Aurora is proposing an alternative to address its potential formation of fine particulate matter ($PM_{2.5}$) from sulfur dioxide. According to a 2008 report by the Northeast States for Coordinated Air Use Management (NESCAUM), for every 10 percentage point increase in the moisture content of wood, the $PM_{2.5}$ emissions increase by 65% to 167%. The increase in emissions is due to increased amount of wood needed to evaporate the extra moisture and poor combustion conditions leading to reduced heat transfer efficiency. Wood fuel use may double if wet wood were burned as opposed to dry wood.[16] Aurora is proposing to develop and operate a firewood drying kiln using district heat from the Aurora plant to help mitigate the use of wet wood. The general idea is that, along with district heat conversions, Aurora would offset its potential $PM_{2.5}$ formation by providing dry wood to the community from a kiln. The kiln would require 3.5 mmbtu/hour of thermal loading from district heating. The initial moisture content in the wood is assumed to be around 50%; the kiln would evaporate 35% of the moisture to a wood moisture content of 15% or less. By conditioning solid fuel (fire wood) to be used in homes, district heating is effectively expanded without the cost of installation.

[16] ADEC. 2014. *Moderate Area State Implementation Plan. Appendix III.D.5.7.* pg 22.

4.1 Equivalent Emissions

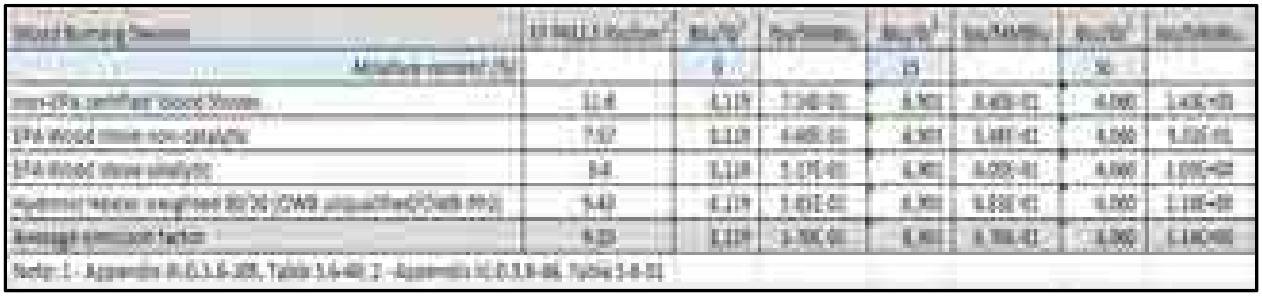
The state has derived a method for comparing direct emissions of pollutants to $PM_{2.5}$ concentration. Using this methodology, point source SO_2 emissions, wood smoke emissions, and heating oil SO_2 can be correlated to $PM_{2.5}$ concentration. Based on 22% of modeled SO_2 concentration from point sources at ground level, a ratio of 5.5 tons SO_2 emissions is estimated to form 1 $\mu g/m^3$ of $PM_{2.5}$ as ammonium sulfate. Likewise, a ratio of 0.3 tons of wood smoke emissions is estimated to form 1 $\mu g/m^3$ of $PM_{2.5}$.[17] Using the fore mentioned conversions, Aurora estimated the power plants SO_2 emissions equivalent to wood smoke emissions. Based on an emission rate at Aurora of 608.3 tons/year of SO_2 (1.67 tpd), the wood smoke emission equivalent is 181 lbs/day [1.67 TPD/ (5.5 tons SO_2 from major sources/1 $\mu g/m^3$) x 0.3 tons of wood smoke/1 $\mu g/m^3$ x 2000 lbs/ton]. The equivalent annual wood smoke emission to 608.3 tons of SO_2 emission is proposed to be mitigated through drying wood by reducing 35% moisture from cord wood.

Table 9: SO2 Conversion to Wood Smoke Equivalent Emission

Source of Emissions	SO_2 Emissions (tpd)	$SO_2/PM_{2.5}$ (tpd)/($\mu g/m^3$)	Wood Smoke/$PM_{2.5}$ (tpd)/($\mu g/m^3$)	Wood Smoke Equivalent (lbs/day)
Aurora Energy	1.67	5.5	0.3	181
Displaced Heating Oil Use - DH	0.01	0.8	0.3	10

The emission reduction for $PM_{2.5}$ in lbs/MMBtu was derived using the ADEC's referenced information within the Appendices of the Moderate Area State Implementation Plan (See Tables 10 & 11). The average emission rate for wood burning devices at 50% moisture (1.14 lbs/MMBtu) was subtracted from the average emission rate for wood burning devices at 15% moisture (0.67 lbs/MMBtu). The equivalent amount of cords needed to account for 100% of Aurora's annual SO_2 emissions is 8,495 cords per year.

Table 10: Emission Factors based on wood moisture content



[17] ADEC. 2014. Moderate Area State Implementation Plan. Appendix III.D.5.7. pg 132.

Table 11: Calculation to determine how much kiln dried wood is necessary to mitigate AE's SO_2 emissions.

PM 2.5 Daily Emissions Reduction (Scenario 2) (lbs/day)	181
PM 2.5 Annual Emissions Reduction (lbs/year)	66,003
Spruce weight at 20% moisture	2,330
Dry Wood (%) moisture	15
Wet Wood (%) moisture	50
Emission Diff. wet vs. dry (lbs/MMBtu)	4.69E-01
Daily Wood processing minimum (MMBtu/year)	140,695
Cords per year	8,495
cords/load	42
Loads per year	202

4.2 Firewood Kiln Economics

The capital cost and annualized cost of the kiln is much less than that of the other BACT alternatives. The cost effectiveness is determined by a $/Cost ratio based on drying wood at a maximum potential of 8,495 cords of wood to reduce, effectively, 608.3 tons per year of SO_2-equivalent emission. The annualized cost is used to derive the cost effectiveness ratio of $980 per ton of pollutant removed.

Table 12: Cost Effectiveness of Kiln

Control Technology	PM 2.5 Reduction (tpy)	Equivalent SO2 Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Cost ($/year)	Cost Effectiveness ($/ton SO_2)
Wood Kiln	32.5	608.3	$ 1,500,000	$ 736,078	$ 980

Unlike a traditional BACT approach, the effective emission reduction is hinged on the marketability of dry wood. Aurora plans to market the kiln dried wood as a benefit from a performance and air quality standpoint. The Fairbanks Northstar Borough, ADEC and EPA all have an important role in enforcing the use of dry wood for home heating the NAA.

5.0 Proposed Alternative BACT - Biomass Co-Firing

Aurora's boilers are subject to 40 CFR 63 subpart JJJJJJ. Under the rule, the Chena Power Plant (CPP) boiler units are classified as coal-fired boilers. The definition of coal-fired boiler subcategory extends to coal boilers that burn up to 15% biomass on a total fuel annual heat input basis. This flexibility in definition would allow Aurora to burn up to 15% biomass and still retain its classification as a coal-fired boiler. Aurora has been involved in a projects with Alaska Center for Energy and Power (ACEP) and the US Forestry Service using biomass (wood chips and refuse) as a substitute for coal. The projects did not demonstrate much of a change to the current operations; however, the material used had a significant amount of moisture (40%) and was not uniform. Sizing of the material was an issue and created problems. Biomass refuse and chips were not appropriately sized and created issues with material feeding through the auxiliary coal feed system. Also, due to density differences, material segregation within the bunkers occurred; wood chips tended to be pushed to the top of the coal. Ultimately, the lessons learned from the project were that with the right material sizing and processing, biomass could be used in the boilers to

help increase efficiency. As noted by operators during the project, the biomass burned off quickly leaving holes within the coal bed which allowed for air pockets which qualitatively made coal combustion more effective. The theory is that air voids left after the biomass was burned off facilitated greater air-to-fuel contact. Also, the rapid burning of the biomass may have increased the heat of the coal bed which helped coal combustion. Although this theory has not been vetted though rigorous research, the potential benefits of using biomass within the process may be substantial. At the very least, biomass has very little sulfur and could be a measure to mitigate the emissions of SO_2 from the plant.

The material used during the biomass project at Aurora was unprocessed and, consequently, not uniform. If the biomass material was processed and met some consistency standards there could be a significant measurable gain in efficiency. As such, processed biomass in the form of industrial grade pellets can provide a consistent sizing which would be compatible with the sizing of the stoker coal used at the Chena Power Plant (CPP). The benefit of using an industrial grade pellet is that the anticipated heat content of the pellets are assumed to be upwards of 8300 btu/lb, the moisture content is near 0%, and there is very little sulfur in the fuel. The cons of using an industrial grade biomass pellet is the cost of the fuel which could be as high as $295/ton. At this cost, the use of biomass is not economical. Furthermore, Aurora has not determined whether or not enough raw timber supply is available around the Fairbanks area to accommodate a consistent 15% blend rate. However, if waste biomass material, such as sawdust or bark, from local wood sellers were processed into pellets the raw material could be acquired at a low cost.

5.1 Biomass Economics

Biomass pellets, due to their lack of sulfur, could be used as mitigation for SO_2 emissions. As stated above, the negative aspect of pellets is in the cost and potential lack of access to raw material supply. In order to derive a price point for pellets that would be acceptable as a control technology, a cost effectiveness value of $3,125/ton SO_2 removed is used as a reference. This is a conservative estimate derived by the state in the moderate area SIP.[18] If the 5-year average revenue generated by the plant is divided by the 5-year average coal use we get a value of $79.09 revenue/ton of coal. Pellets have a higher btu/lb content than the coal and pellets have no moisture. To account for this discrepancy, coal heating value is considered after the evaporation of moisture. The energy needed to vaporize free moisture (h_{vap} =1049 btu/lb @ 77F) is multiplied by the moisture fraction of coal to derive the heat content of the coal at 0% moisture. When comparing the wood pellets to coal, the 5-year average heat content (7623 btu/lb) and moisture (29%) is considered. The heating value of coal without moisture is 7304 btu/lb (7623 btu/lb –

Table 13: Biomass and Coal Fuel Revenue/MMBtu

hhv pellets btu/lb	8,300
hhv pellets mmbtu/ton	16.6
hhv coal btu/lb	7,613.05
coal moisture	29%
heat of vaporization of water @ 77F btu/lb	1,049.70
coal btu/lb -vaporized free water	7,304
coal mmbtu/ton -vaporized free water	14.6
pellet coal equivalent	1.14
revenue/ton of coal	$ 79.09
revenue/mmbtu of coal	$ 5.41
revenue/mmbtu of pellets	$ 4.76

[18] ADEC. 2014. Moderate Area State Implementation Plan. Appendix III.D.5.7. pg 132.

1049.7*29/100). Pellets would have a heating content of 8300 btu/lb and no moisture. If the price of the pellets were $84/ton, the cost effectiveness value would be $3,093.04/ton SO_2 removed.

The emission reduction potential using pellets at 15% total fuel loading is 91.24 tons of $S0_2$ per year. Aurora is actively pursuing this concept; however, running the boiler with 15% biomass has not been tested and a supply of industrial wood pellets at the preferred price has not been identified nor has the availability of the raw material supply been verified.

Table 14: Biomass Cost Effectiveness Calculation

capital investment (hopper modification to auxillary coal feed system)	$300,000.00
loan period (years)	$5.00
interest rate (%)	8%
monthly loan amount	$6,082.92
Annual loan amount	$72,995.04
Burden for 0.5 man equivalent (2016)	$65,520
5-year avg Annual Coal (tons)	221,758.29
5-year avg coal sulfur (%)	0.14%
potential max SO2 (tons/yr)	608.24
Annual pellets (%)	15%
Annual pellets (tons)	29,272.22
emission reduction (tons/yr)	91.24
Cost pellets ($/ton)	$84.00
Annual cost	$2,597,381.16
Annual revenue	$2,315,186.17
annual burden of pellets	$282,194.99
cost/ton removed	3,093.04

6.0 Proposed Alternative BACT – Reduction in Potential to Emit

Aurora proposes to monitor the stack gas emissions out of the common stack. The purpose of the monitoring would be to ensure compliance with an SO_2 emission rate of 190 ppm. Instead of taking a reduction in the sulfur content of the coal or PTE for SO_2 emissions, monitoring the stack gas emissions and maintaining a rolling 30-day average at or under 190 ppm ensures that the plant is not exceeding a certain loading rate equal to 0.25% coal sulfur content. Using the SO_2 emission calculation in the Air Quality Operating permit AQ0315TVP03 Rev. 1, Condition 22.1.c; a stack gas concentration of 7.5% O_2; and adjusting the S% to 0.25 (in this ultimate analysis the S% is 0.26), the SO_2 concentration is 188 ppm as illustrated below:

Figure 1: SO_2 emission calculation



As mentioned, 190 ppm of SO2 emissions on a 30-day rolling average represents an overall PTE reduction from 0.4% sulfur content to 0.25% while still allowing flexibility with respect to coal quality exceeding 0.25% sulfur.

7.0 Precursor Demonstration

As part of the Serious SIP development, states are required to develop Best Available Control Measures for all source sectors that emit $PM_{2.5}$ and the four major precursor gases (e.g., NOx, SO_2, NH_4, and VOC). The analysis specific to the major stationary source is a Best Available Control Technology analysis. Within the rule, if the state determines through a precursor demonstration that controls for a precursor gas are not needed for attaining the standard, then the controls for a precursor gas are not required to be implemented.[19] The regulations provide for three kinds of precursor analyses, comprehensive (which consider precursor emissions from all sources in the nonattainment area), Major stationary source (which consider precursor emissions from major sources), and Nonattainment New Source Review (which considers potential precursor emissions from new sources). [20] For each of the first two analyses, there are two varieties available to the state: a concentration-based analysis (compares the precursor contributions to a numerical threshold) and a sensitivity-based analysis which consider other factors to evaluate if reductions in the precursor emissions would significantly reduce $PM_{2.5}$ levels in a nonattainment area.

The ADEC has successfully demonstrated that oxides of nitrogen NOx and VOC are not a significant precursors to the area. The NOx precursor demonstrations included a comprehensive demonstration with a sensitivity based analysis for the community and a Major Stationary Source – concentration based analysis which demonstrated that major sources are not a significant contributor to the nitrate-based particulate formation.[21] The state also conducted a comprehensive, concentration-based analysis for SO_2 and concluded that SO_2 emissions in the NAA contribute 5.4 $\mu g/m^3$ in the Fairbanks area and 4.9 $\mu g/m^3$ of $PM_{2.5}$ in the North Pole area. Since these concentrations exceed the significance threshold of 1.3 $\mu g/m^3$ (now 1.5 $\mu g/m^3$)[22], the ADEC proposes not to conduct a sensitivity-based precursor demonstration nor are they considering a major source precursor demonstration.

EPA's draft precursor guidance recognizes that the significance of a precursors contribution is determined based on the facts and circumstances of the area which include source characteristics such as source type, stack height, and location.[23] The rationale for doing a precursor demonstration fits with the site-specific factors listed in the EPA guidance, namely tall stacks. However, the ADEC and EPA have been resistant to performing or further considering a Major Source precursor demonstration.

Aurora sought a third party opinion (Ramboll Environmental) regarding the possibility of a successful SO_2 precursor demonstration that could demonstrate that major stationary sources are an insignificant part of the contribution to the nonattainment area. According with the EPA's precursor demonstration guidelines, a successful major stationary source precursor demonstration must show that SO_2 emissions do not contribute significantly to violations of the $PM_{2.5}$ standard (1.5 $\mu g/m^3$). If the 'contribution-based'

[19] ADEC. 2018. Preliminary Draft Precursor Demonstration.
[20] See 40 C.F.R. § 51.1006
[21] ADEC. 2018. Preliminary Draft Precursor Demonstration.
[22] Draft EPA (2016b) guidance recommended 1.3 $\mu g/m^3$ for the $PM_{2.5}$ 24-hour NAAQS as the appropriate threshold to identify insignificant contributions to $PM_{2.5}$ concentrations. A more recent updated technical basis document, EPA (2018) now recommends a threshold for identifying significance of 1.5 $\mu g/m^3$.
[23] EPA's 2016 Draft $PM_{2.5}$ Precursor Demonstration Guidance.

analysis indicates that the impact exceeds 1.5 $\mu g/m^3$, then a 'sensitivity-based' analysis may be conducted to show that a reduction of SO_2 emissions in the range of 30-70% would have only an insignificant impact on lowering $PM_{2.5}$.

Two main hurdles exist to conducting a credible SO_2 precursor demonstration; 1) the large contribution of sulfate by major and minor source contribution to the nonattainment area; and 2) the large under prediction of sulfate mass through the model (CMAQ). In essence, while the SO_2 sources are observed to contribute significantly to the $PM_{2.5}$ nonattainment area, current modeling systems are not sufficiently accurate to provide a reliable estimate of the impacts of emission reductions from SO_2.

Utilizing the ADEC's information within the Moderate Area SIP, Aurora's third party consult suggests that there is relevant data to suggest major sources are potentially insignificant contributors to the NAA.

> "…data analyses and modeling conducted for the Fairbanks moderate area SIP provide some significant information which suggests that in fact major source SO_2 emissions may not contribute significantly to $PM_{2.5}$ nonattainment."[24]

As such, a Major Source SO_2 precursor demonstration must be pursued by the ADEC. It is an undue burden for Aurora and other major sources within the NAA subject to the requirements of control measures (BACT, and more likely MSM) considering that there is data to suggest that major sources could be insignificant. Even though updating models and research into the chemistry of sulfate particulate formation is costly and time consuming, it is due diligence on the agencies part to further elucidate the impact of major sources. Ultimately, Aurora will continue to pursue alternative control measures as proposed within this document under the assumption that the agencies (ADEC and EPA) will continue to vet the sulfate contribution disparity between model and observed values with the perspective of major stationary source contribution.

8.0 Conclusion

The proposed BACT alternatives in this document and accompanying information demonstrate that the ADEC proposed BACT are economically infeasible and do very little to solve the air quality problem in the nonattainment area. EPA, the State of Alaska, as well as the local community understand and agree that the majority of the $PM_{2.5}$ problem in the area is from home heating sources. Aurora contends that requiring the implementation of the ADEC proposed BACT controls would cause the pollution problem to worsen due to our district heat customer's refusal to accept a higher cost heating product and instead switching to fuel oil, or wood burning.

Aurora does not believe ADEC has demonstrated that the point sources, or more specifically Aurora, are contributing to the $PM_{2.5}$ problem in a significant enough way to warrant the need for additional control measures. Aurora believes that a precursor demonstration would prove this assertion one way or another. Aurora believes a precursor demonstration is possible and requests that ADEC and the EPA move forward with conducting a precursor demonstration in parallel with the implementation of the SIP. Should a precursor demonstration show that the point sources do not cross over the significance threshold, all point sources should be released from further compliance with the $PM_{2.5}$ requirements.

Even though Aurora is not convinced that major source emissions exceed the significance threshold for $PM_{2.5}$ within the NAA, Aurora is interested in being a part of the solution to reduce $PM_{2.5}$. Aurora's

[24] Memo. Ramboll. "Summary of issues related to SO_2 precursor demonstration for Fairbanks".2018.

proposed alternative BACT controls are more effective from an environmental perspective and cost substantially less than the ADEC proposed BACT controls. The table below shows the potential amount of SO_2 and $PM_{2.5}$ removed from the NAA by Aurora's proposed alternative BACT.

Table 15: Summary of BACT Alternatives and Potential Emission Reduction

Emissions	SO2 (tpy)	PM 2.5 (tpy)	Qualifying Parameters
District Heating (Current Operating Conditions)	42 tpy at ground level	2 tons at ground level	250,000 – 300,000 mmbtu per year
District Heating (Potential Expansion)	24 tpy at ground level	1 ton at ground level	100 mmbtu/hr expansion potential
Wood Kiln	608.3tpy	33 tons at ground level	8495 cords/yr
Biomass Co-Firing	91.2 tpy	--	15% by fuel heat input from industrial pellets
Potential to emit reduction	38% reduction in PTE (854 tpy)	--	State upper limit of 500 ppm over 3 hours. Proposed 190 ppm as a new PTE
Total Potential Reduction	1,619.5 tpy	36 tpy	

As clearly shown in this table, the environmental benefits from Aurora's proposed alternative BACTs will positively impact the current NAA. Aurora is prepared to move forward with implementing these alternative BACTs as soon as ADEC is able to provide Aurora with the assurance that additional control measures or fees will not be required in order to demonstrate compliance with the PM2.5 regulations for the NAA.

Aurora is committed to continuing to work with ADEC, EPA and the local community in working toward meaningful solutions to the air quality problem in Interior Alaska.

Appendix A (Economic Analysis Spreadsheets – V1)

Air Pollution Control Cost Estimation Spreadsheet
For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N_2 and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 5.13). The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

What type of fuel does the unit burn?

Is the SCR for a new boiler or retrofit of an existing boiler?

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1.5

Simpson, Aaron:
No basis was provided to justify a retrofit factor reflecting greater than average difficulty for installation of selective catalytic reduction on the boilers.

High retrofit cost factors may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement).

Aurora: Location of the catalyst, if it has to be installed within a temperature range of 500-800F, would be the top of the boilers just before the economizer and air preheater. It's a titght fit, limited space, asbestos abatement necessary, duct work is complex and

Complete all of the highlighted data fields:

What is the rating at full load capacity (MMBtu/hr)?	497	MMBtu/hr
What is the higher heating value (HHV) of the fuel?	7,560	Btu/lb
What is the estimated actual annual fuel consumption?	569,114,000	lbs/year

Simpson, Aaron:
Typical Gross As Received. http://www.usibelli.com/coal/data-sheet

Enter the sulfur content (%S) = 0.20 percent by weight

Simpson, Aaron:
Typical Gross As Received. http://www.usibelli.com/coal/data-sheet

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	2.35	11,814
Sub-Bituminous	1	0.2	7,560
Lignite	0	0.91	6,534

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the net plant heat input rate (NPHR)	18	MMBtu/MW
Plant Elevation	450	Feet above sea level

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

Method 1
Method 2
Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions ($NO_{x_{in}}$) to SCR	0.37	lb/MMBtu
NOx Removal Efficiency (EF) provided by vendor	80	percent
Stoichiometric Ratio Factor (SRF)	0.525	

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Simpson, Aaron:
Assuming baseline of 0.5 lb/MMBtu from New Source Performance Standards, Subpart Da – Technical Support for Proposed Revisions to NOx Standard, U.S. EPA, Office of Air Quality Planning and Standards, EPA-453/R-94-012, June 1997.

Aurora: Emission Inventory rate based on 2011 source testing.

Simpson, Aaron:
EPA's Air Pollution Control Technology Fact Sheet indicating 70 - 90 percent control. https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	10	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	179,783.2	acfm

Simpson, Aaron:
April 7, 2016 Source Test

Aurora: Source Test dscf = 162098.5.

162098.5 dscf/(1-Bws) = acfm; Bws = 0.0984.

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	30	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	310	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516	ft^3/min-MMBtu/hour

Simpson, Aaron:
April 7, 2016 Source Test

Concentration of reagent as stored (C_{stored})	50	percent*
Density of reagent as stored (ρ_{stored})	71	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30	days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3
19% aqueous NH_3	58 lbs/ft^3

Select the reagent used

Enter the cost data for the proposed SCR:

Desired dollar-year	2016			
CEPCI for 2016	536.4	Enter the CEPCI value for 2016	584.6	2012 CEPCI
Annual Interest Rate (i)	5.25	Percent		
Reagent ($Cost_{reag}$)	1.62	$/gallon for a 50 percent solution of urea		
Electricity ($Cost_{elect}$)	0.210	$/kWh		
Catalyst cost ($CC_{replace}$)	160.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst*		
Operator Labor Rate	63.00	$/hour (including benefits)		

Simpson, Aaron:
GVEA rates. http://www.gvea.com/rates/rates

CEPCI = Chemical Engineering Plant Cost Index

* $160/cf is a default value for the catalyst cost. User should enter actual value, if known.

Operator Hours/Day | 4.00 hours/day* | * 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	1.62	Based on the average of vendor quotes from 2011 - 2013.	
Electricity Cost ($/kWh)	0.039	Average annual electricity cost for utilities is based on 2014 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3.	$0.210/kWh GVEA rates. http://www.gvea.com/rates/rates
Percent sulfur content for Coal (% weight)	0.31	Average sulfur content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	0.20 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/Coal_data.php
Higher Heating Value (HHV) (Btu/lb)	8,730	2014 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7,560 Btu/lb (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/Coal_data.php
Catalyst Cost ($/cubic foot)	160	Cichanowicz, J.E. "Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies", July 2013.	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	497	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	575,888,889	lbs/year	
Actual Annual fuel consumption (Mactual) =		569,114,000	lbs/year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.80		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.99	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8657	hours	
NOx Removal Efficiency (EF) =	(NOxin- NOxout)/NOxin =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	147.11	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	636.77	tons/year	
NOx removal factor (NRF) =	EF/80	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr}	179,783	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$	30.03	/hour	
Residence Time	$1/V_{space}$	0.03	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	(%S/100)x(64/32)*1E6)/HHV =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.5	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.316	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x Noxadj x Sadj x (Tadj/Nscr)	5,986.26	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	187	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1	12	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	215	ft^2
Reactor length and width dimentions for a square reactor =	$(A_{SCR})^{0.5}$	14.7	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	84	feet

Reagent Data:

Type of reagent used: Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole

Density = 71 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SFR \times MW_R)/MW_{NOx}$ =	101	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	202	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	21	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	15,296	gallons (storage needed to store a 30 day reagent supply)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0669

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	365.95	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$14,132,761	in 2016 dollars
Reagent Preparation Cost (RPC) =	$2,348,710	in 2016 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2016 dollars
Balance of Plant Costs (BPC) =	$3,333,099	in 2016 dollars
Total Capital Investment (TCI) =	$25,758,941	in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 270{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 270{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$14,132,761 in 2016 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 490{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 490{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$2,348,710 in 2016 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)
For Coal-Fired Utility Boilers >25MW:
$BPC = 460{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.42} \times ELEVF \times RF$
For Coal-Fired Industrial Boilers >250 MMBtu/hour:
$BPC = 460{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$

Balance of Plant Costs (BOP_{cost}) =	$3,333,099 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,193,040 in 2016 dollars
Indirect Annual Costs (IDAC) =	$1,728,014 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$2,921,054 in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$128,795 in 2016 dollars
Annual Reagent Cost =	$q_{sol} \times Cost_{reag} \times t_{op}$ =	$297,936 in 2016 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$665,284 in 2016 dollars
Annual Catalyst Replacement Cost =		$101,026 in 2016 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	* Calculation Method 1 selected.
Method 2 (for coal-fired utility boilers):	$B_{MW} \times 0.4 \times (CoalF)^{2.9} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3$	
Direct Annual Cost =		$1,193,040 in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,305 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,723,709 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,728,014 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,921,054 per year in 2016 dollars
NOx Removed =	637 tons/year
Cost Effectiveness =	$4,587 per ton of NOx removed in 2016 dollars

Air Pollution Control Cost Estimation Spreadsheet
For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologoies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, repectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SNCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

What type of fuel does the unit burn?

Is the SCR for a new boiler or retrofit of an existing boiler?

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	497	MMBtu/hr
What is the higher heating value (HHV) of the fuel?	7,560	Btu/lb
What is the estimated actual annual fuel consumption?	569,114,000	lbs/year
Is the boiler a fluid-bed boiler?		
Enter the net plant heat input rate (NPHR)	18	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned:

Enter the sulfur content (%S) = 0.20 percent by weight

or

Select the appropriate SO_2 emission rate:

Ash content (%Ash): 7 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	2.35	10.4	11,814	2.79
Sub-Bituminous	1	0.2	7	7,560	2.79
Lignite	0	0.93	14.3	6,534	1.85

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.37	lb/MMBtu
NOx Removal Efficiency (EF) provided by vendor (Enter "UNK" if value is not known)	40	percent
Estimated Normalized Stoichiometric Ratio (NSR)	1.05	

*The NSR value of 1.05 is a default value. User should enter actual value, if known.

Plant Elevation: 450 Feet above sea level

Concentration of reagent as stored (C_{stored})	50	percent*
Denisty of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	50	percent
Number of days reagent is stored ($t_{storage}$)	30	days
Estimated equipment life	20	Years

*The reagent concentration of 50% is a default value. User should enter actual value, if known.

Densities of typical SNCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3
19% aqueous NH_3	58 lbs/ft^3

Select the reagent used

Enter the cost data for the proposed SNCR:

Desired dollar-year	2016			
CEPCI for 2016	536.4	Enter the CEPCI value for 2016	584.6	2012 CEPCI
Annual Interest Rate (i)	5.25	Percent		
Fuel ($Cost_{fuel}$)	2.79	$/MMBtu*		
Reagent ($Cost_{reag}$)	1.62	$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0088	$/gallon*		
Electricity ($Cost_{elect}$)	0.210	$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	18.00	$/ton*		

CEPCI = Chemical Engineering Plant Cost Index

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the the value used and the reference source . . .
Reagent Cost	$1.62/gallon of 50% urea solution	Based on vendor quotes collected in 2014.	
Water Cost ($/gallon)	0.0088	Average combined water/wastewater rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.039	Average annual electricity cost for industrial plants is based on 2014 price data compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-861 and 861S, (http://www.eia.gov/electricity/data.cfm#sales).	$0.210/kWh GVEA rates. http://www.gvea.com/rates/rates
Fuel Cost ($/MMBtu)	2.79	Weighted average cost based on average 2014 fuel cost data for power plants compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA 923, "Power Plant Operations Report." Available at http://www.eia.gov/electricity/data/eia923/.	
Ash Disposal Cost ($/ton)	18	Average ash disposal costs based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent sulfur content for Coal (% weight)	2.35	Average sulfur content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	0.20 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet
Percent ash content for Coal (% weight)	10.40	Average ash content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet
Higher Heating Value (HHV) (Btu/lb)	11,814	2014 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7,560 Btu/lb (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	497	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	575,888,889	lbs/year	
Actual Annual fuel consumption (Mactual) =		569,114,000	lbs/year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.80		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.99	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8657	hours	
NOx Removal Efficiency (EF) =	(Noxin - NOxout)/Noxin =	40.00	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	73.56	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	318.39	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminuous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	(%S/100)x(64/32)*1E6)/HHV =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 450 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.5	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used: Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole

Density = 71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea	126	lb/hour
Reagent Usage Rate (m_{sol}) =	mreagent/Csol =	252	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	27	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x tstorage x 24)/Reagent Density =	19,121	gallons (storage needed to store a 30 day reagent supply)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0820

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electrcity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	5.04	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.11	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1E6)/HHV =	1.05	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,099,024 in 2016 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2016 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,677,090 in 2016 dollars
Total Capital Investment (TCI) =	$6,208,948 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$2,099,024 in 2016 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

Balance of Plan Costs (BOP_{cost}) =	$2,677,090 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$477,565	in 2016 dollars
Indirect Annual Costs (IDAC) =	$511,631	in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$989,197	in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$93,134	in 2016 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$372,444	in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$9,166	in 2016 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0	in 2016 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$2,739	in 2016 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$82	in 2016 dollars
Direct Annual Cost =		$477,565	in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,794	in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$508,837	in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$511,631	in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$989,197	per year in 2016 dollars
NOx Removed =	318	tons/year
Cost Effectiveness =	$3,107	per ton of NOx removed in 2016 dollars

Four Boilers Dry Sorbent Injection System - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Gross Output based on sum of turbines rated size; 20MW, 5MW, and 2.5 MW)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0. Site-specific considerations provided by Aurora in 12/22/17 BACT Addendum)
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input (Heat Rate is higher because district heating is not included in unit size)
SO2 Rate	D	(lb/MMBtu)	0.36	<-- User Input (Based on source testing 2011)
Type of Coal	E		sub-bituminous	<-- User Input
Particulate Capture	F		Baghouse	<-- User Input
Milled Trona	G		**TRUE**	Based on in-line milling equipment
Removal Target	H	(%)	70	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with a Baghouse = 80% Milled Trona with Baghouse = 90% Simplified correlation; 70% removal with baghouse. S&L (2013)
Heat Input	J	(Btu/hr)	495,000,000	A*C*1000
NSR	K		1.55	Unmilled Trona with an ESP = if(H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if(H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with an BGH = if(H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with an BGH = if(H<40,0.0160*H,0.208e^(0.0281*H)) 1.55 Recommended for a baghouse at a target of 70% removal. S&L (2013)
Trona Feed Rate	M	(ton/hr)	0.33	(1.2011x10^-06)*K*A*C*D
Sorbent Waste Rate	N	(ton/hr)	0.222	(0.7035-0.00073696*H/K)*M Based on a final reaction product of Na2SO4 and unreacted dry sorbent as Na2CO3.
Fly Ash Waste Rate	P	(ton/hr)	0.92	(A*C)*Ash incoal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2, HHV = 11,000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2, HHV = 8,400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2, HHV = 7,200 <-- User Input (Usibelli Coal: Ash in Coal = 0.07; Boiler Ash Removal = 0.6; HHV = 7,560)
Aux Power	**Q**	**(%)**	**0.24**	=if Milled Trona M*20/A else M*18/A
Trona Cost	R	($/ton)	550	<-- User Input (based on Stanley Consultant price reference)
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	T	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Operating Labor Rate	U	($/hr)	63	<-- User Input (Labor cost including all benefits [AE 2016])

IPM Model - Updates to Cost and Performance for APC Technologies - Dry Sorbent Injection for SO2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for USEPAhttps://www.epa.gov/sites/production/files/2015 07/documents/append5_4.pdf

Capital Cost Calculation (2012 dollars)				Comments
Includes - Equipment, installation, building, foundations, electrical, and a retrofit difficulty factor of 1.5				
Base Module (BM) ($) Unmilled Trona = if(M>25 then (682,000*B*M) else 6,833,000*B*(M^0.284) Milled Trona = if(M>25 then (750,000*B*M) else 7,516,000*B*(M^0.284)	=	$	14,169,111	Base DSI module includes all equipment from unloading to injection,but not including field installation
BM ($/kW)	=	$	515	Base module cost per kW
Total Project Cost				
A1 = 20% of BM	=	$	2,833,822	Engineering and construction management costs (CC Manual) (Stanley Consultants)
A2 = 10% of BM	=	$	1,416,911	Labor adjustment for 6 x 10 hour shift premium, per diem, etc. (CC Manual)
A3 = 10% of BM	=	$	1,416,911	Contractor profit and fees (CC Manual) (Stanley Consultants)
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**19,836,755**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs	=	**$**	**721**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	991,838	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**20,828,593**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs	=	**$**	**757**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	=			AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**=**	**$**	**20,682,000**	**Total project cost (Spreadsheet = $20,828,523; Stanley Consultants cost estimate = $20,682,000)**
TPC ($/kW)	=	**$**	**752**	**Total project cost per kW**

Dry Sorbent Injection System - Chena Power Plant

Direct Annual Costs				
Fixed Operating and Maintenance (O&M) Cost				
FOMO ($/kW yr) = (2 additional operators)*(2080)*U/(A*1000)	=	$	9.53	Fixed O&M additional operating labor costs (2 additional operators is more realistic)
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	=	$	3.43	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	0.33	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**=**	**$**	**13.29**	**Total Fixed O&M costs ($/kW yr)**
Variable O&M Cost				
VOMR ($/MWh) = M*R/A	=	$	6.64	Variable O&M costs for Trona reagent
VOMW ($/MWh) = (N+P)*S/A	=	$	2.07	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injectio
VOMP ($/MWh) = Q*T*10	=	$	0.507	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**=**	**$**	**9.21**	**Total Variable O&M Costs ($/MW yr)**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	$	219,322	CC Manual
Administrative charges (2% of total capital investment)	=	$	413,640	CC Manual
Property tax (1% of total capital investment)	=	$	206,820	CC Manual
Insurance (1% of total capital investment)	=	$	206,820	CC Manual
Capital Recovery Factor (CRF) = [i $(1+i)^n$] / [$(1+i)^n$ - 1]				
i = Interest rate (%) 5.25				Revise interest rate to prime (currently 5.25%) per EPA comment
n = Equipment life (years) 30				Reality is 10 years of useful life of the oldside; 30 years control equipment lifetime based on EPA comments on ADEC Prelim. BACT
CRF = 0.0669	=	$	1,383,976	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**2,430,578**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**5,015,463**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 $)	**=**	**$**	**4,601,940**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		781	
SO_2 REMOVAL EFFICIENCY, %	=		70	
TOTAL SO_2 REMOVED, tons	=		546	
SO_2 COST-EFFECTIVENESS, $/ton removed	**=**	**$**	**8,423**	

Four Boilers Spray Dry Absorber - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Conservative assumption based on total heat input of 497 MMBtu/hour)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0. Site-specific considerations provided by Aurora in 12/22/17 BACT Addendum)
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input
SO2 Rate	D	(lb/MMBtu)	0.36	<-- User Input (SDA FGD Estimation only valid up to 3lb/MMBtu SO2 Rate)
Type of Coal	E		sub-bituminous	<-- User Input
Coal Factor	F		1.05	Bituminous = 1, Sub-Bituminous=1.05, Lignite=1.07
Heat Rate Factor	G		1.800	C/10000
Heat Input	H	(Btu/hr)	495,000,000	A*C*1000
Lime Rate	K	(ton/hr)	0.122	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 Removal)
Waste Rate	L	(ton/hr)	0.280	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**2.462**	(0.000547*(D^2)+0.00649*D+1.3)*F*G **Should be used for model input**
Makeup Water Rate	N	(1000 gph)	2.876	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	240	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf) (GVEA Limestone cost)
Waste Disposal Cost	Q	($/ton)	30	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Aux Power Cost	R	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Makeup Water Cost	S	($/1000 gal)	7.17	<-- User Input (http://www.newsminer.com/water-rates/article_11a2ba10-c211-562e-8da9-87dd16a7b104.htm)
Operating Labor Rate	T	($/hr)	63	Labor cost including all benefits

IPM Model - Updates to Cost and Performance for APC Technologies - SDA FGD for SO2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for US EPA.
https://www.epa.gov/sites/production/files/2015-07/documents/chapter_5_appendix_5-1b_sda_fgd.pdf

Capital Cost Calculation (2012 dollars)				Comments
Includes - Equipment, installation, building, foundations, electrical, and a retrofit difficulty factor of 1.5				
BMR ($) = if(A>600 then (A*92,000) else 566,000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	=	$	13,028,350	Base module absorber island cost
BMF ($) = if(A>600 then (A*48,700) else 300,000*(A^0.716))*B*(D*G)^0.2	=	$	4,426,798	Base module reagent preparation and waste recycle/handling cost
BMB ($) = if(A>600 then (A*129,900) else 799,000*(A^0.716))*B*(F*G)^0.4	=	$	16,587,654	Base module balance of plan costs inlcuding: ID or booster fans, piping, ductwork, electrical, etc.
BM ($) = BMR + BMF + BMB	=	$	34,042,802	Total base module cost including retrofit factor
BM ($/kW)	=	$	1,238	Base module cost per kW
Total Project Cost				
A1 = 10% of BM	=	$	3,404,280	Engineering and construction management costs
A2 = 10% of BM	=	$	3,404,280	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.
A3 = 10% of BM	=	$	3,404,280	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**44,255,642**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs =	=	**$**	**1,609**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	2,212,782	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**46,468,425**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs =	=	**$**	**1,690**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	=	$	4,646,842	AFUDC (based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2	=	**$**	**51,115,267**	**Total project cost**
TPC ($/kW) - Includes Owner's Costs and AFUDC =	=	**$**	**1,859**	**Total project cost per kW**

Spray Dry Absorber - Chena Power Plant

Direct Annual Costs				
Fixed Operating and Maintenance (O&M) Cost				
FOMO ($/kW yr) = (4 additional operators)*(2080)*T/(A*1000)	=	$	38.12	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	=	$	12.38	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	1.29	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**=**	**$**	**51.79**	**Total Fixed O&M costs**
Variable O&M Cost				
VOMR ($/MWh) = K*P/A	=	$	1.06	Variable O&M costs for lime reagent
VOMW ($/MWh) = L*Q/A	=	$	0.31	Variable O&M costs for waste disposal
VOMP ($/MWh) = M*R*10	=	$	5.17	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	=	$	0.75	Variable O&M costs for makeup water
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**=**	**$**	**7.29**	**Total Variable O&M Costs**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	$	854,570	CC Manual
Administrative charges (2% of total capital investment)	=	$	1,022,305	CC Manual
Property tax (1% of total capital investment)	=	$	511,153	CC Manual
Insurance (1% of total capital investment)	=	$	511,153	CC Manual
Capital Recovery Factor (CRF) = $[i (1+i)^n] / [(1+i)^n - 1]$				
i = Interest rate (%) 5.25				
n = Equipment life (years) 30				
CRF = 0.0669	=	$	3,420,477	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**6,319,657**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**9,499,458**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 $)	**=**	**$**	**8,716,232**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		781	
SO_2 REMOVAL EFFICIENCY, %	=		90	
TOTAL SO_2 REMOVED, tons	=		702	
SO_2 COST-EFFECTIVENESS, $/ton removed	**=**	**$**	**12,408**	

Four Boilers Wet Scrubber - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Conservative assumption based on a total heat input of 497 MMBtu/hr)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0) Sargent and Lundy has a drop down menu for selection of an additional waste water treatment plant facility, but no capital or operational cost are implemented so it is not reproduced here.
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input
SO2 Rate	D	(lb/MMBtu)	0.36	<-- User Input
Type of Coal	E		sub-bituminous	<-- User Input
Coal Factor	F		1.05	Bituminous = 1, Sub-Bituminous = 1.05, Lignite = 1.07
Heat Rate Factor	G		1.8	C/10000
Heat Input	H	(Btu/hr)	495,000,000	A*C*1000
Limestone Rate	K	(ton/hr)	0.16	17.52*A*D*G/2000
Waste Rate	L	(ton/hr)	0.283	1.811*K
Aux Power	**M**	**(%)**	**2.098**	(1.05e^(0.155*D))*F*G
Makeup Water Rate	N	(1000 gph)	3.913	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/ton)	240	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Waste Disposal Cost	Q	($/ton)	30	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Aux Power Cost	R	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Makeup Water Cost	S	($/1000 gal)	7.17	<-- User Input (http://www.newsminer.com/water-rates/article_11a2ba10-c211-562e-8da9-87dd16a7b104.html)
Operating Labor Rate	T	($/hr)	63	Labor cost including all benefits

IPM Model - Updates to Cost and Performance for APC Technologies - Wet FGD for SO2 Control Cost Development Methodology, August 2010, prepared by Sargent & Lundy LLC for US EPA.
https://www.epa.gov/sites/production/files/2015-07/documents/chapter_5_appendix_5-1a_wet_fgd.pdf

Capital Cost Calculation (2012 dollars)				Comments
Includes - Equipment, installation, building, foundations, electrical, minor physical/chemical waste water treatment, and a retrofit difficulty factor of 1.5				
BMR ($) = 550,000*(B)*((F*G)^0.6)*((D/2)^0.02)*(A^0.716)	=	$	12,531,374	Base absorber island cost
BMF ($) = 190,000*(B)*((D*G)^0.3)*(A^0.716)	=	$	2,684,600	Base reagent preparation cost
BMW ($) = 100,000*(B)*((D*G)^0.45)*(A^0.716)	=	$	1,323,921	Base waste handling cost
BMB ($) = 1,010,000*(B)*((F*G)^0.4)*(A^0.716)	=	$	20,968,123	Base balance of plan cost including: ID or booster fans, new wet chimney, piping, ductwork, minor waste water treatment, etc…
BMWW ($) =	=	$	-	Base wastewater treatment facility, beyond minor physical/chemcial treatment
Base Module (BM) ($) = BMR + BMF + BMW + BMB + BMWW	=	$	37,508,019	Total base cost including retrofit factor
BM ($/kW)	=	$	1,364	Base cost per kW
Total Project Cost				
A1 = 10% of BM	=	$	3,750,802	Engineering and construction management costs (CC Manual)
A2 = 10% of BM	=	$	3,750,802	Labor adjustment for 6 x 10 hour shift premium, per diem, etc. (CC Manual)
A3 = 10% of BM	=	$	3,750,802	Contractor profit and fees (CC Manual)
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**48,760,424**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs =	=	**$**	**1,773**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	2,438,021	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**51,198,446**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs =	=	**$**	**1,862**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	=	$	5,119,844.55	AFUDC (based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2	=	**$**	**56,318,290**	**Total project cost**
TPC ($/kW) - Includes Owner's Costs and AFUDC =	=	**$**	**2,048**	**Total project cost per kW**

Wet Scrubber - Chena Power Plant

Direct Annual Costs				
Fixed O&M Cost				
FOMO ($/kW yr) = (6 additional operators)*(2080)* T/(A*1000)	=	$	28.59	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	=	$	13.64	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	1.02	Fixed O&M additional administrative labor costs
FOMWW ($/kW yr) =		$	-	Fixed O&M costs for wastewater treatment facility
FOM ($/kW yr) = FOMO + FOMM + FOMA + FOMWW	**=**	**$**	**43.25**	**Total Fixed O&M costs ($/kW yr)**
Variable O&M Cost				
VOMR ($/MWh) = K*P/A	=	$	1.36	Variable O&M costs for limestone reagent
VOMW ($/MWh) = L*Q/A	=	$	0.31	Variable O&M costs for waste disposal
VOMP ($/MWh) = M*R*10	=	$	4.41	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	=	$	1.02	Variable O&M costs for makeup water
VOMWW ($/MWh) =	=	$	-	Variable O&M costs for wastewater treatment facility
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW	**=**	**$**	**7.10**	**Total Variable O&M Costs ($/MW yr)**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	$	713,645	CC Manual
Administrative charges (2% of total capital investment)	=	$	1,126,366	CC Manual
Property tax (1% of total capital investment)	=	$	563,183	CC Manual
Insurance (1% of total capital investment)	=	$	563,183	CC Manual
Capital Recovery Factor (CRF) = [i $(1+i)^n$] / [$(1+i)^n$ - 1]				
i = Interest rate (%) 5.25				
n = Equipment life (years) 30				
CRF = 0.0669	=	$	3,768,647	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**6,735,024**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**9,634,230**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 $)	**=**	**$**	**8,839,892**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		781	
SO_2 REMOVAL EFFICIENCY, %	=		99	
TOTAL SO_2 REMOVED, tons	=		773	
SO_2 COST-EFFECTIVENESS, $/ton removed	**=**	**$**	**11,440**	Does not include costs associated with building and maintaining a wastewater treatment facility

Appendix B (Economic Analysis Spreadsheets – V2)

Air Pollution Control Cost Estimation Spreadsheet
For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N_2 and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 5.13). The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

What type of fuel does the unit burn?

Is the SCR for a new boiler or retrofit of an existing boiler?

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1.5

Simpson, Aaron:
No basis was provided to justify a retrofit factor reflecting greater than average difficulty for installation of selective catalytic reduction on the boilers.

High retrofit cost factors may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement).

Aurora: Location of the catalyst, if it has to be installed within a temperature range of 500-800F, would be the top of the boilers just before the economizer and air preheater. It's a titght fit, limited space, asbestos abatement necessary, duct work is complex and

Complete all of the highlighted data fields:

What is the rating at full load capacity (MMBtu/hr)?	497	MMBtu/hr
What is the higher heating value (HHV) of the fuel?	7,560	Btu/lb
What is the estimated actual annual fuel consumption?	569,114,000	lbs/year

Simpson, Aaron:
Typical Gross As Received. http://www.usibelli.com/coal/data-sheet

Enter the sulfur content (%S) = 0.20 percent by weight

Simpson, Aaron:
Typical Gross As Received. http://www.usibelli.com/coal/data-sheet

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	2.35	11,814
Sub-Bituminous	1	0.2	7,560
Lignite	0	0.91	6,534

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the net plant heat input rate (NPHR)	18	MMBtu/MW
Plant Elevation	450	Feet above sea level

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

Method 1
Method 2
Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.37	lb/MMBtu
NOx Removal Efficiency (EF) provided by vendor	80	percent
Stoichiometric Ratio Factor (SRF)	0.525	

Simpson, Aaron:
Assuming baseline of 0.5 lb/MMBtu from New Source Performance Standards, Subpart Da – Technical Support for Proposed Revisions to NOx Standard, U.S. EPA, Office of Air Quality Planning and Standards, EPA-453/R-94-012, June 1997.

Aurora: Emission Inventory rate based on 2011 source testing.

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Simpson, Aaron:
EPA's Air Pollution Control Technology Fact Sheet indicating 70 - 90 percent control. https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	10	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	179,783.2	acfm

Simpson, Aaron:
April 7, 2016 Source Test

Aurora: Source Test dscf = 162098.5.

162098.5 dscf/(1-Bws) = acfm; Bws = 0.0984.

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	15	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	310	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516	ft^3/min-MMBtu/hour

Simpson, Aaron:
April 7, 2016 Source Test

Concentration of reagent as stored (C_{stored})	50	percent*
Density of reagent as stored (ρ_{stored})	71	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30	days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3
19% aqueous NH_3	58 lbs/ft^3

Select the reagent used

Enter the cost data for the proposed SCR:

Desired dollar-year	2016			
CEPCI for 2016	536.4	Enter the CEPCI value for 2016	584.6	2012 CEPCI
Annual Interest Rate (i)	5.25	Percent		
Reagent ($Cost_{reag}$)	1.62	$/gallon for a 50 percent solution of urea		
Electricity ($Cost_{elect}$)	0.210	$/kWh		
Catalyst cost ($CC_{replace}$)	160.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst*		
Operator Labor Rate	63.00	$/hour (including benefits)		

Simpson, Aaron:
GVEA rates. http://www.gvea.com/rates/rates

CEPCI = Chemical Engineering Plant Cost Index

* $160/cf is a default value for the catalyst cost. User should enter actual value, if known.

Operator Hours/Day | 4.00 hours/day* | * 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	1.62	Based on the average of vendor quotes from 2011 - 2013.	
Electricity Cost ($/kWh)	0.039	Average annual electricity cost for utilities is based on 2014 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3.	$0.210/kWh GVEA rates. http://www.gvea.com/rates/rates
Percent sulfur content for Coal (% weight)	0.31	Average sulfur content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	0.20 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/Coal_data.php
Higher Heating Value (HHV) (Btu/lb)	8,730	2014 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7,560 Btu/lb (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/Coal_data.php
Catalyst Cost ($/cubic foot)	160	Cichanowicz, J.E. "Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies", July 2013.	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	497	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	575,888,889	lbs/year	
Actual Annual fuel consumption (Mactual) =		569,114,000	lbs/year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.80		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.99	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8657	hours	
NOx Removal Efficiency (EF) =	(NOxin- NOxout)/NOxin =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	147.11	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	636.77	tons/year	
NOx removal factor (NRF) =	EF/80	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr}	179,783	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$	30.03	/hour	
Residence Time	$1/V_{space}$	0.03	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	(%S/100)x(64/32)*1E6)/HHV =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.5	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.316	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x Noxadj x Sadj x (Tadj/Nscr)	5,986.26	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	187	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1	12	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	215	ft^2
Reactor length and width dimentions for a square reactor =	$(A_{SCR})^{0.5}$	14.7	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	84	feet

Reagent Data:

Type of reagent used: Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole

Density = 71 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SFR \times MW_R)/MW_{NOx}$ =	101	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	202	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	21	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	15,296	gallons (storage needed to store a 30 day reagent supply)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0980

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	365.95	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$14,132,761	in 2016 dollars
Reagent Preparation Cost (RPC) =	$2,348,710	in 2016 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2016 dollars
Balance of Plant Costs (BPC) =	$3,333,099	in 2016 dollars
Total Capital Investment (TCI) =	$25,758,941	in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 270{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 270{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$14,132,761 in 2016 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 490{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 490{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$2,348,710 in 2016 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)
For Coal-Fired Utility Boilers >25MW:
$BPC = 460{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.42} \times ELEVF \times RF$
For Coal-Fired Industrial Boilers >250 MMBtu/hour:
$BPC = 460{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$

Balance of Plant Costs (BOP_{cost}) =	$3,333,099 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,193,040 in 2016 dollars
Indirect Annual Costs (IDAC) =	$2,528,093 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$3,721,132 in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$128,795 in 2016 dollars
Annual Reagent Cost =	$q_{sol} \times Cost_{reag} \times t_{op}$ =	$297,936 in 2016 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$665,284 in 2016 dollars
Annual Catalyst Replacement Cost =		$101,026 in 2016 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	* Calculation Method 1 selected.
Method 2 (for coal-fired utility boilers):	$B_{MW} \times 0.4 \times (CoalF)^{2.9} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3$	
Direct Annual Cost =		$1,193,040 in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,305 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$2,523,788 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$2,528,093 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,721,132 per year in 2016 dollars
NOx Removed =	637 tons/year
Cost Effectiveness =	$5,844 per ton of NOx removed in 2016 dollars

Air Pollution Control Cost Estimation Spreadsheet
For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologoies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, repectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SNCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

What type of fuel does the unit burn?

Is the SCR for a new boiler or retrofit of an existing boiler?

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.: 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	497	MMBtu/hr
What is the higher heating value (HHV) of the fuel?	7,560	Btu/lb
What is the estimated actual annual fuel consumption?	569,114,000	lbs/year
Is the boiler a fluid-bed boiler?		
Enter the net plant heat input rate (NPHR)	18	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned:

Enter the sulfur content (%S) = 0.20 percent by weight

or

Select the appropriate SO_2 emission rate:

Ash content (%Ash): 7 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	2.35	10.4	11,814	2.79
Sub-Bituminous	1	0.2	7	7,560	2.79
Lignite	0	0.91	14.3	6,534	1.85

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.37	lb/MMBtu
NOx Removal Efficiency (EF) provided by vendor (Enter "UNK" if value is not known)	40	percent
Estimated Normalized Stoichiometric Ratio (NSR)	1.05	

*The NSR value of 1.05 is a default value. User should enter actual value, if known.

Plant Elevation: 450 Feet above sea level

Concentration of reagent as stored (C_{stored})	50	percent*
Denisty of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	50	percent
Number of days reagent is stored ($t_{storage}$)	30	days
Estimated equipment life	15	Years

*The reagent concentration of 50% is a default value. User should enter actual value, if known.

Densities of typical SNCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3
19% aqueous NH_3	58 lbs/ft^3

Select the reagent used

Enter the cost data for the proposed SNCR:

Desired dollar-year	2016			
CEPCI for 2016	536.4	Enter the CEPCI value for 2016	584.6	2012 CEPCI
Annual Interest Rate (i)	5.25	Percent		
Fuel ($Cost_{fuel}$)	2.79	$/MMBtu*		
Reagent ($Cost_{reag}$)	1.62	$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0088	$/gallon*		
Electricity ($Cost_{elect}$)	0.210	$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	18.00	$/ton*		

CEPCI = Chemical Engineering Plant Cost Index

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the the value used and the reference source . . .
Reagent Cost	$1.62/gallon of 50% urea solution	Based on vendor quotes collected in 2014.	
Water Cost ($/gallon)	0.0088	Average combined water/wastewater rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.039	Average annual electricity cost for industrial plants is based on 2014 price data compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-861 and 861S, (http://www.eia.gov/electricity/data.cfm#sales).	$0.210/kWh GVEA rates. http://www.gvea.com/rates/rates
Fuel Cost ($/MMBtu)	2.79	Weighted average cost based on average 2014 fuel cost data for power plants compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA 923, "Power Plant Operations Report." Available at http://www.eia.gov/electricity/data/eia923/.	
Ash Disposal Cost ($/ton)	18	Average ash disposal costs based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent sulfur content for Coal (% weight)	2.35	Average sulfur content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	0.20 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet
Percent ash content for Coal (% weight)	10.40	Average ash content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet
Higher Heating Value (HHV) (Btu/lb)	11,814	2014 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7,560 Btu/lb (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	497	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	575,888,889	lbs/year	
Actual Annual fuel consumption (Mactual) =		569,114,000	lbs/year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.80		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.99	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8657	hours	
NOx Removal Efficiency (EF) =	(Noxin - NOxout)/Noxin =	40.00	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	73.56	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	318.39	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminuous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	(%S/100)x(64/32)*1E6)/HHV =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 450 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.5	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used: Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole

Density = 71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea	126	lb/hour
Reagent Usage Rate (m_{sol}) =	mreagent/Csol =	252	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	27	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x tstorage x 24)/Reagent Density =	19,121	gallons (storage needed to store a 30 day reagent supply)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0980

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electrcity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	5.04	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.11	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1E6)/HHV =	1.05	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,099,024 in 2016 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2016 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,677,090 in 2016 dollars
Total Capital Investment (TCI) =	$6,208,948 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$2,099,024 in 2016 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

Balance of Plan Costs (BOP_{cost}) =	$2,677,090 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$477,565	in 2016 dollars
Indirect Annual Costs (IDAC) =	$611,129	in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$1,088,694	in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$93,134	in 2016 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$372,444	in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$9,166	in 2016 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0	in 2016 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$2,739	in 2016 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$82	in 2016 dollars
Direct Annual Cost =		$477,565	in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,794	in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$608,335	in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$611,129	in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,088,694	per year in 2016 dollars
NOx Removed =	318	tons/year
Cost Effectiveness =	$3,419	per ton of NOx removed in 2016 dollars

Four Boilers Dry Sorbent Injection System - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	**27.5**	<-- User Input (Gross Output based on sum of turbines rated size; 20MW, 5MW, and 2.5 MW)
Retrofit Factor	B		**1.5**	<-- User Input (An "average" retrofit has a factor of 1.0. Site-specific considerations provided by Aurora in 12/22/17 BACT Addendum)
Gross Heat Rate	C	(Btu/kWh)	**18,000**	<-- User Input (Heat Rate is higher because district heating is not included in unit size)
SO2 Rate	D	(lb/MMBtu)	**0.30**	<-- User Input (Based on source testing 2011)
Type of Coal	E		sub-bituminous	<-- User Input
Particulate Capture	F		Baghouse	<-- User Input
Milled Trona	G		**TRUE**	Based on in-line milling equipment
Removal Target	H	(%)	**70**	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with a Baghouse = 80% Milled Trona with Baghouse = 90% Simplified correlation; 70% removal with baghouse. S&L (2013)
Heat Input	J	(Btu/hr)	**495,000,000**	A*C*1000
NSR	K		1.55	Unmilled Trona with an ESP = if(H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if(H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with an BGH = if(H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with an BGH = if(H<40,0.0160*H,0.208e^(0.0281*H)) 1.55 Recommended for a baghouse at a target of 70% removal. S&L (2013)
Trona Feed Rate	M	(ton/hr)	0.28	(1.2011x10^-06)*K*A*C*D
Sorbent Waste Rate	N	(ton/hr)	0.185	(0.7035-0.00073696*H/K)*M Based on a final reaction product of Na2SO4 and unreacted dry sorbent as Na2CO3.
Fly Ash Waste Rate	P	(ton/hr)	**0.92**	(A*C)*Ash incoal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2, HHV = 11,000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2, HHV = 8,400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2, HHV = 7,200 <-- User Input (Usibelli Coal: Ash in Coal = 0.07; Boiler Ash Removal = 0.6; HHV = 7,560)
Aux Power	**Q**	**(%)**	**0.20**	=if Milled Trona M*20/A else M*18/A
Trona Cost	R	($/ton)	**550**	<-- User Input (based on Stanley Consultant price reference)
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	T	($/kWh)	**0.21**	<-- User Input (http://www.gvea.com/rates/rates)
Operating Labor Rate	U	($/hr)	63	<-- User Input (Labor cost including all benefits [AE 2016])

IPM Model - Updates to Cost and Performance for APC Technologies - Dry Sorbent Injection for SO2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for USEPAhttps://www.epa.gov/sites/production/files/2015 07/documents/append5_4.pdf

Capital Cost Calculation (2012 dollars)				Comments
Includes - Equipment, installation, building, foundations, electrical, and a retrofit difficulty factor of 1.5				
Base Module (BM) ($) Unmilled Trona = if(M>25 then (682,000*B*M) else 6,833,000*B*(M^0.284) Milled Trona = if(M>25 then (750,000*B*M) else 7,516,000*B*(M^0.284)	=	$	14,169,111	Base DSI module includes all equipment from unloading to injection,but not including field installation
BM ($/kW)	=	$	515	Base module cost per kW
Total Project Cost				
A1 = 20% of BM	=	$	2,833,822	Engineering and construction management costs (CC Manual) (Stanley Consultants)
A2 = 10% of BM	=	$	1,416,911	Labor adjustment for 6 x 10 hour shift premium, per diem, etc. (CC Manual)
A3 = 10% of BM	=	$	1,416,911	Contractor profit and fees (CC Manual) (Stanley Consultants)
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**19,836,755**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs	=	**$**	**721**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	991,838	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**20,828,593**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs	=	**$**	**757**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	=			AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**=**	**$**	**20,682,000**	**Total project cost (Spreadsheet = $20,828,523; Stanley Consultants cost estimate = $20,682,000)**
TPC ($/kW)	=	**$**	**752**	**Total project cost per kW**

Dry Sorbent Injection System - Chena Power Plant

Direct Annual Costs				
Fixed Operating and Maintenance (O&M) Cost				
FOMO ($/kW yr) = (2 additional operators)*(2080)*U/(A*1000)	=	$	9.53	Fixed O&M additional operating labor costs (2 additional operators is more realistic)
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	=	$	3.43	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	0.33	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**=**	**$**	**13.29**	**Total Fixed O&M costs ($/kW yr)**
Variable O&M Cost				
VOMR ($/MWh) = M*R/A	=	$	5.53	Variable O&M costs for Trona reagent
VOMW ($/MWh) = (N+P)*S/A	=	$	2.00	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injectio
VOMP ($/MWh) = Q*T*10	=	$	0.423	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**=**	**$**	**7.96**	**Total Variable O&M Costs ($/MW yr)**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	$	219,322	CC Manual
Administrative charges (2% of total capital investment)	=	$	413,640	CC Manual
Property tax (1% of total capital investment)	=	$	206,820	CC Manual
Insurance (1% of total capital investment)	=	$	206,820	CC Manual
Capital Recovery Factor (CRF) = [i $(1+i)^n$] / [$(1+i)^n$ - 1]				
i = Interest rate (%) 5.25				Revise interest rate to prime (currently 5.25%) per EPA comment
n = Equipment life (years) 15				Reality is 10 years of useful life of the oldside; 30 years control equipment lifetime based on EPA comments on ADEC Prelim. BACT
CRF = 0.0980	=	$	2,026,363	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**3,072,965**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**5,356,087**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 $)	**=**	**$**	**4,914,480**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		651	
SO_2 REMOVAL EFFICIENCY, %	=		70	
TOTAL SO_2 REMOVED, tons	=		456	
SO_2 COST-EFFECTIVENESS, $/ton removed	**=**	**$**	**10,785**	

Four Boilers Spray Dry Absorber - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Conservative assumption based on total heat input of 497 MMBtu/hour)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0. Site-specific considerations provided by Aurora in 12/22/17 BACT Addendum)
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input
SO2 Rate	D	(lb/MMBtu)	0.30	<-- User Input (SDA FGD Estimation only valid up to 3lb/MMBtu SO2 Rate)
Type of Coal	E		sub-bituminous	<-- User Input
Coal Factor	F		1.05	Bituminous = 1, Sub-Bituminous=1.05, Lignite=1.07
Heat Rate Factor	G		1.800	C/10000
Heat Input	H	(Btu/hr)	495,000,000	A*C*1000
Lime Rate	K	(ton/hr)	0.101	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 Removal)
Waste Rate	L	(ton/hr)	0.234	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**2.461**	(0.000547*(D^2)+0.00649*D+1.3)*F*G **Should be used for model input**
Makeup Water Rate	N	(1000 gph)	2.874	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	240	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf) (GVEA Limestone cost)
Waste Disposal Cost	Q	($/ton)	30	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Aux Power Cost	R	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Makeup Water Cost	S	($/1000 gal)	7.17	<-- User Input (http://www.newsminer.com/water-rates/article_11a2ba10-c211-562e-8da9-87dd16a7b104.htm)
Operating Labor Rate	T	($/hr)	63	Labor cost including all benefits

IPM Model - Updates to Cost and Performance for APC Technologies - SDA FGD for SO2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for US EPA.
https://www.epa.gov/sites/production/files/2015-07/documents/chapter_5_appendix_5-1b_sda_fgd.pdf

Capital Cost Calculation (2012 dollars)				Comments
Includes - Equipment, installation, building, foundations, electrical, and a retrofit difficulty factor of 1.5				
BMR ($) = if(A>600 then (A*92,000) else 566,000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	=	$	13,004,722	Base module absorber island cost
BMF ($) = if(A>600 then (A*48,700) else 300,000*(A^0.716))*B*(D*G)^0.2	=	$	4,268,968	Base module reagent preparation and waste recycle/handling cost
BMB ($) = if(A>600 then (A*129,900) else 799,000*(A^0.716))*B*(F*G)^0.4	=	$	16,587,654	Base module balance of plan costs inlcuding: ID or booster fans, piping, ductwork, electrical, etc.
BM ($) = BMR + BMF + BMB	=	$	33,861,344	Total base module cost including retrofit factor
BM ($/kW)	=	$	1,231	Base module cost per kW
Total Project Cost				
A1 = 10% of BM	=	$	3,386,134	Engineering and construction management costs
A2 = 10% of BM	=	$	3,386,134	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.
A3 = 10% of BM	=	$	3,386,134	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**44,019,747**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs =	=	**$**	**1,601**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	2,200,987	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**46,220,735**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs =	=	**$**	**1,681**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	=	$	4,622,073	AFUDC (based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2	=	**$**	**50,842,808**	**Total project cost**
TPC ($/kW) - Includes Owner's Costs and AFUDC =	=	**$**	**1,849**	**Total project cost per kW**

Spray Dry Absorber - Chena Power Plant

Direct Annual Costs				
Fixed Operating and Maintenance (O&M) Cost				
FOMO ($/kW yr) = (4 additional operators)*(2080)*T/(A*1000)	=	$	38.12	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	=	$	12.31	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	1.29	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**=**	**$**	**51.73**	**Total Fixed O&M costs**
Variable O&M Cost				
VOMR ($/MWh) = K*P/A	=	$	0.88	Variable O&M costs for lime reagent
VOMW ($/MWh) = L*Q/A	=	$	0.25	Variable O&M costs for waste disposal
VOMP ($/MWh) = M*R*10	=	$	5.17	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	=	$	0.75	Variable O&M costs for makeup water
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**=**	**$**	**7.06**	**Total Variable O&M Costs**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	$	853,468	CC Manual
Administrative charges (2% of total capital investment)	=	$	1,016,856	CC Manual
Property tax (1% of total capital investment)	=	$	508,428	CC Manual
Insurance (1% of total capital investment)	=	$	508,428	CC Manual
Capital Recovery Factor (CRF) = $[i (1+i)^n] / [(1+i)^n - 1]$				
i = Interest rate (%) 5.25				
n = Equipment life (years) 15				
CRF = 0.0980	=	$	4,981,433	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**7,868,614**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**10,990,629**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 $)	**=**	**$**	**10,084,456**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		651	
SO_2 REMOVAL EFFICIENCY, %	=		90	
TOTAL SO_2 REMOVED, tons	=		586	
SO_2 COST-EFFECTIVENESS, $/ton removed	**=**	**$**	**17,213**	

Four Boilers Wet Scrubber - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Conservative assumption based on a total heat input of 497 MMBtu/hr)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0) Sargent and Lundy has a drop down menu for selection of an additional waste water treatment plant facility, but no capital or operational cost are implemented so it is not reproduced here.
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input
SO2 Rate	D	(lb/MMBtu)	0.30	<-- User Input
Type of Coal	E		sub-bituminous	<-- User Input
Coal Factor	F		1.05	Bituminous = 1, Sub-Bituminous = 1.05, Lignite = 1.07
Heat Rate Factor	G		1.8	C/10000
Heat Input	H	(Btu/hr)	495,000,000	A*C*1000
Limestone Rate	K	(ton/hr)	0.13	17.52*A*D*G/2000
Waste Rate	L	(ton/hr)	0.236	1.811*K
Aux Power	**M**	**(%)**	**2.079**	(1.05e^(0.155*D))*F*G
Makeup Water Rate	N	(1000 gph)	3.908	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/ton)	240	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Waste Disposal Cost	Q	($/ton)	30	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Aux Power Cost	R	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Makeup Water Cost	S	($/1000 gal)	7.17	<-- User Input (http://www.newsminer.com/water-rates/article_11a2ba10-c211-562e-8da9-87dd16a7b104.html)
Operating Labor Rate	T	($/hr)	63	Labor cost including all benefits

IPM Model - Updates to Cost and Performance for APC Technologies - Wet FGD for SO2 Control Cost Development Methodology, August 2010, prepared by Sargent & Lundy LLC for US EPA.
https://www.epa.gov/sites/production/files/2015-07/documents/chapter_5_appendix_5-1a_wet_fgd.pdf

Capital Cost Calculation (2012 dollars)				Comments
Includes - Equipment, installation, building, foundations, electrical, minor physical/chemical waste water treatment, and a retrofit difficulty factor of 1.5				
BMR ($) = 550,000*(B)*((F*G)^0.6)*((D/2)^0.02)*(A^0.716)	=	$	12,485,962	Base absorber island cost
BMF ($) = 190,000*(B)*((D*G)^0.3)*(A^0.716)	=	$	2,542,315	Base reagent preparation cost
BMW ($) = 100,000*(B)*((D*G)^0.45)*(A^0.716)	=	$	1,220,076	Base waste handling cost
BMB ($) = 1,010,000*(B)*((F*G)^0.4)*(A^0.716)	=	$	20,968,123	Base balance of plan cost including: ID or booster fans, new wet chimney, piping, ductwork, minor waste water treatment, etc…
BMWW ($) =	=	$	-	Base wastewater treatment facility, beyond minor physical/chemcial treatment
Base Module (BM) ($) = BMR + BMF + BMW + BMB + BMWW	=	$	37,216,477	Total base cost including retrofit factor
BM ($/kW)	=	$	1,353	Base cost per kW
Total Project Cost				
A1 = 10% of BM	=	$	3,721,648	Engineering and construction management costs (CC Manual)
A2 = 10% of BM	=	$	3,721,648	Labor adjustment for 6 x 10 hour shift premium, per diem, etc. (CC Manual)
A3 = 10% of BM	=	$	3,721,648	Contractor profit and fees (CC Manual)
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**48,381,420**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs =	=	**$**	**1,759**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	2,419,071	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**50,800,491**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs =	=	**$**	**1,847**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	=	$	5,080,049.08	AFUDC (based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2	=	**$**	**55,880,540**	**Total project cost**
TPC ($/kW) - Includes Owner's Costs and AFUDC =	=	**$**	**2,032**	**Total project cost per kW**

Wet Scrubber - Chena Power Plant

Direct Annual Costs				
Fixed O&M Cost				
FOMO ($/kW yr) = (6 additional operators)*(2080)* T/(A*1000)	=	$	28.59	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	=	$	13.53	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	1.02	Fixed O&M additional administrative labor costs
FOMWW ($/kW yr) =		$	-	Fixed O&M costs for wastewater treatment facility
FOM ($/kW yr) = FOMO + FOMM + FOMA + FOMWW	**=**	**$**	**43.14**	**Total Fixed O&M costs ($/kW yr)**
Variable O&M Cost				
VOMR ($/MWh) = K*P/A	=	$	1.14	Variable O&M costs for limestone reagent
VOMW ($/MWh) = L*Q/A	=	$	0.26	Variable O&M costs for waste disposal
VOMP ($/MWh) = M*R*10	=	$	4.37	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	=	$	1.02	Variable O&M costs for makeup water
VOMWW ($/MWh) =	=	$	-	Variable O&M costs for wastewater treatment facility
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW	**=**	**$**	**6.78**	**Total Variable O&M Costs ($/MW yr)**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	$	711,875	CC Manual
Administrative charges (2% of total capital investment)	=	$	1,117,611	CC Manual
Property tax (1% of total capital investment)	=	$	558,805	CC Manual
Insurance (1% of total capital investment)	=	$	558,805	CC Manual
Capital Recovery Factor (CRF) = [i (1+i)^n] / [(1+i)^n - 1]				
i = Interest rate (%) 5.25				
n = Equipment life (years) 15				
CRF = 0.0980	=	$	5,475,016	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**8,422,112**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**11,241,441**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 $)	**=**	**$**	**10,314,589**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		651	
SO_2 REMOVAL EFFICIENCY, %	=		99	
TOTAL SO_2 REMOVED, tons	=		644	
SO_2 COST-EFFECTIVENESS, $/ton removed	**=**	**$**	**16,005**	Does not include costs associated with building and maintaining a wastewater treatment facility

Appendix C (Coal Analyses Summary)

Coal Analyses Summary (As Received)					
Year	Report	Coal	HHV	Moisture	Sulfur
Units		(tons)	(btu/lb)	(%)	(%)
2013	A	103,122.35	7,670	27.22	0.15
2013	B	115,917.00	7,599	27.95	0.17
2014	A	117,659.65	7,652	27.89	0.15
2014	B	103,979.45	7,617	27.86	0.14
2015	A	103,904.80	7,599	29.16	0.14
2015	B	120,758.30	7,610	29.02	0.15
2016	A	115,282.20	7,683	31.21	0.12
2016	B	107,687.35	7,604	29.23	0.14
2017	A	106,040.35	7,567	32.20	0.11
2017	B	114,440.00	7,529	32.52	0.10
Weighted average		221,758.29	7,613	29.44	0.14

Usibelli Coal Mine

Coal Analysis

Analysis Results for 6-1-13 to 6-30-13

Customer	Date	#Cores/RFU	%H20	CLA	%V	%C	%S	SiNo	Bench	Seam	Tons

Weighted Averages Summary

Usibelli Coal Mine

Run Numbers

Analysis Results for FY 2013

Customer	Date	#Cars	DTU	%H20	%A	%V	%C	%S	Btu	Beach	Seam	Tons

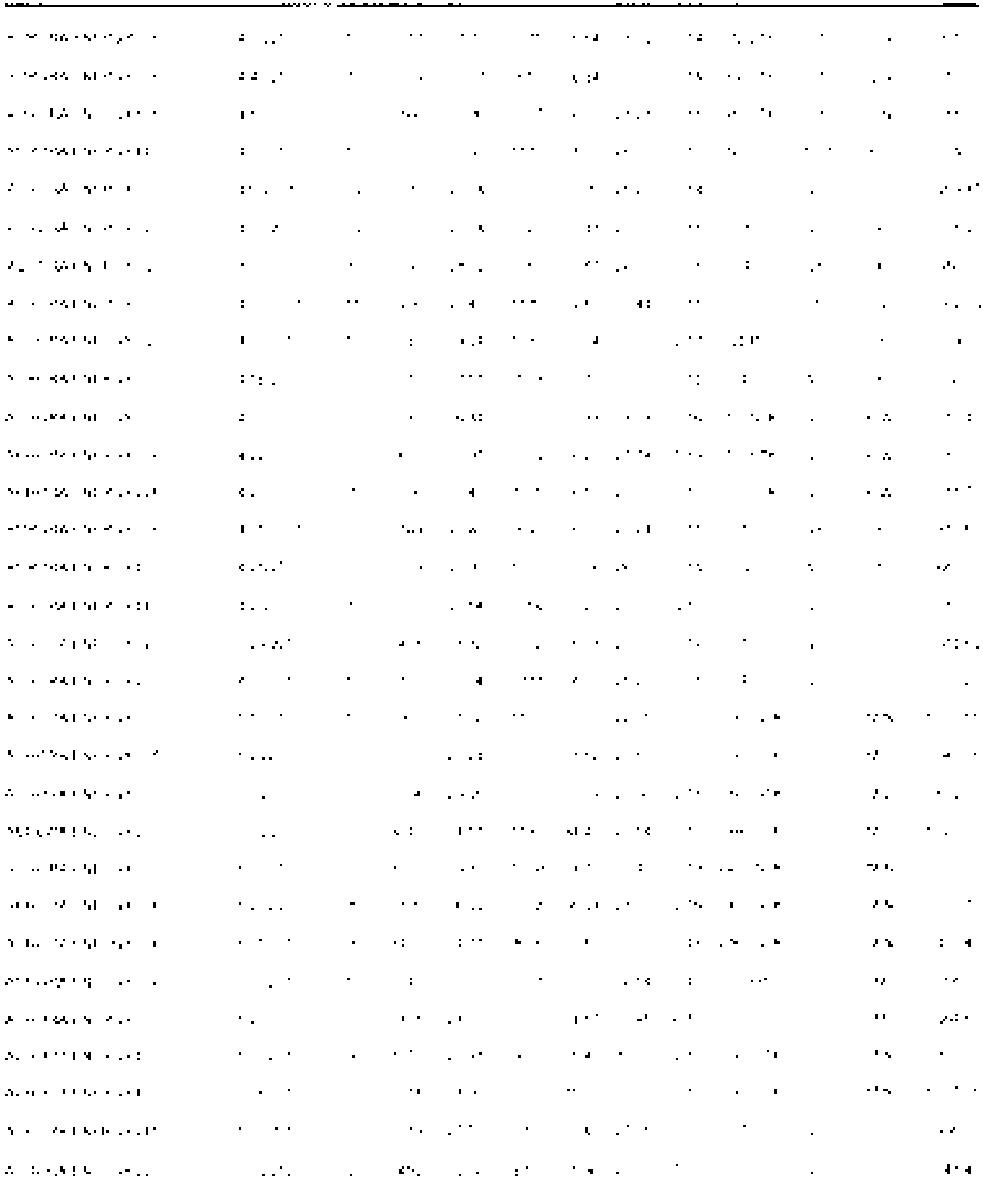
Rock Samples

Analytes Reported for 1/1/2013 to 6/30/2013

[illegible]
[illegible]
[illegible]
[illegible]

Run Examples

Employee Pressure for [illegible] to 6/30/13



Ash Analysis

Average Results for 7-1-22 to 6-30-23

Usibelli Coal Mine

Run Sample

Analysis Results for [illegible]

Customer	Date	#Lbs BTU	%H20	%A	%V	%C	%S	Sieve	Reach	Seam	Tons
[illegible]											
[illegible]											
[illegible]											
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Usibelli Coal Mine

Rigol Nomograph

Analysis Results for 1/22/14 12:31:07

Run Summary

Analysis Results for 1/1/2013 to 12/31/2013

| | | |

Usibelli Coal Mine

Run Summary

Analysis Summary for [illegible]

[illegible]											
[illegible]											
[illegible]											

Required Energy Summary

[illegible]											

[illegible]

[illegible]

[illegible]

Usibelli Coal Mine

Run Sample

Analyses Results for [illegible]

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Usibelli Coal Mine

Run Samples

Analysis Results for [illegible]

[illegible]												
[illegible]												
[illegible]												

Usibelli Coal Mine

Run Summary

Analysis Results for 1/1/14 to 2/26/14

Usibelli Coal Mine

Run Summary

Analysis Results for 1-Jan-14 to 6-2014

Weighted Averages Summary

Appendix D (Professional Memos)

RAMBOLL

ENVIRONMENT
& HEALTH

MEMO

To **David Fish, Aurora Energy LLC**
From **Till Stoeckenius**
Subject **Summary of issues related to SO_2 precursor demonstration for Fairbanks**

Date November 15, 2018

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The Alaska Department of Environmental Conservation (ADEC) is currently developing a State Implementation Plan (SIP) for the Fairbanks North Star Borough serious $PM_{2.5}$ nonattainment area (NAA). Fairbanks was reclassified from a moderate $PM_{2.5}$ NAA to a serious $PM_{2.5}$ NAA in June 2017; the serious area SIP is due by December 2018.

As provided for in 40 CFR 51.1006, states can reduce the regulatory burden of complying with $PM_{2.5}$ NAA requirements in the Clean Air Act by conducting $PM_{2.5}$ precursor demonstrations showing that one or more precursors involved in formation of secondary $PM_{2.5}$ do not significantly contribute to violations of the $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS). The current ADEC draft serious area SIP preparation plan includes precursor demonstrations for ammonia (NH_3), nitrogen oxides (NO_x), and volatile organic compounds (VOCs) which conclude that each of these three precursors do not significantly contribute to nonattainment. ADEC did not perform a precursor demonstration for sulfur dioxide (SO_2).

A draft Best Available Control Technology (BACT) demonstration completed by the ADEC as required by the CAA for serious NAAs identifies dry sorbent injection as BACT for the four major SO_2 sources in the Fairbanks NAA. In recognition of the possibility that the SIP may include a requirement for SO_2 controls on their sources without a clear indication of the potential benefits of such controls for reducing ambient $PM_{2.5}$ concentrations, owners of the four major SO_2 sources in the Fairbanks NAA requested (via Aurora Energy) Ramboll's assistance with evaluating possible approaches to conducting a successful major source SO_2 precursor demonstration for Fairbanks.

In accordance with our letter agreement with Aurora of 18 September, Ramboll performed research and analysis related to an SO_2 precursor demonstration for the Fairbanks 24-hour $PM_{2.5}$ serious nonattainment area (NAA). Ramboll reviewed documents describing data analysis and modeling conducted by ADEC and its contractors for the 2014 Fairbanks moderate area SIP and draft analyses

and plans for developing the serious NAA SIP. This included detailed descriptions of emission inventory development, meteorological and photochemical dispersion modeling methods and related sensitivity analyses, air monitoring data analyses and receptor modeling studies and other related materials. Representatives from Ramboll, Aurora Energy and owners of the other major SO_2 sources located within the Fairbanks NAA, along with ADEC and EPA Region X, participated in a conference call to discuss issues involved in conducting a successful major source SO_2 precursor demonstration. We also had several one-on-one conversations with David Fish of Aurora and Robert Ellerman of EPA Region X. A common theme in these discussions was a significant level of skepticism by ADEC and EPA regarding the likelihood of success in developing an approvable major source SO_2 precursor demonstration for the Fairbanks Serious area SIP given uncertainties about sulfate formation mechanisms under Fairbanks winter conditions. A summary of our findings is provided below.

A key element of a NAA SIP is a demonstration that planned emission reductions will result in attainment of the NAAQS in future years. ADEQ uses a computer model (CMAQ) to carry out this attainment demonstration. CMAQ is a photochemical dispersion model which simulates the transport, dispersion, and chemical transformation of emissions from all sources of $PM_{2.5}$ and $PM_{2.5}$ precursors (NH_3, NO_x, VOC, SO_2) affecting the NAA. In order to complete its work within the available time and resources, ADEC is planning to use the same base year $PM_{2.5}$ episodes (Episode 1: 23 January – 11 February 2008 and Episode 2: 2 – 17 November 2008) and modeling approach for the serious NAA SIP attainment demonstration as were used in the moderate area SIP attainment demonstration. This is despite the limited amount of air quality monitoring data available during these episodes and the fact that air quality conditions in Fairbanks have changed significantly since 2008 due to emission reductions during the intervening years. Monitoring of $PM_{2.5}$ component species was conducted at the State Office Building (SOB) in downtown Fairbanks during the 2008 episodes. These data were used in the moderate area SIP to evaluate the ability of CMAQ to accurately reproduce the observed concentrations of $PM_{2.5}$ and its component species.

As shown in Table 1, comparisons of CMAQ predicted $PM_{2.5}$ with observed $PM_{2.5}$ showed over prediction of organic carbon (OC) and elemental carbon (EC) and under predictions of other PM species, including sulfate (SO_4). These over and underpredictions fortuitously balanced each other out, resulting in an apparently accurate prediction of $PM_{2.5}$ total mass. The prediction errors for individual PM species may be the result of an inaccurate emissions inventory or errors in CMAQ (or in the WRF model used to provide meteorological inputs to CMAQ). Of particular note is that CMAQ predicted very little in situ formation of sulfate from SO_2 emissions due to the lack of available oxidizing agents in the model. In technical documents prepared for the Fairbanks moderate area $PM_{2.5}$ SIP, ADEC concluded that CMAQ is under predicting the amount of secondary sulfate formation under the unique Fairbanks winter conditions due to some unknown SO_2 oxidation pathway.

Table 1. Comparison of observed and predicted PM species concentrations at State Office Building monitoring site (average over days with FRM measurements in both 2008 episodes).

Species	Observed (µg/m³)	Predicted (µg/m³)	Bias (%)
$PM_{2.5}$ (total)	36.1	35.7	-1%
OC	17.0	24.5	44%
EC	2.3	4.3	87%
SO_4	6.2	2.1	-66%
NO_3	1.6	1.3	-19%
NH_4	3.1	1.2	-61%
OTH	6.3	2.3	-63%

Source: *Addressing the precursor gases for Fairbanks $PM_{2.5}$ State Implementation Plan.* D. Huff, Alaska Department of Environmental Conservation, 25 September 2014, in Reasonably Available Control Measure (RACM) Analysis (Appendix III.D.5.7 to the Fairbanks $PM_{2.5}$ Moderate State Implementation Plan).

In accordance with EPA's precursor demonstration guidelines, a successful precursor demonstration (in this case for SO_2) must show that SO_2 emissions do not contribute significantly to violations of the $PM_{2.5}$ NAAQS. More specifically, for a major source SO_2 precursor demonstration, the guidance requires a demonstration that eliminating SO_2 emission from all major sources within the NAA would not lower $PM_{2.5}$ concentrations by more than an insignificant amount (defined in the guidance as an amount not exceeding 1.5 µg/m³).[1] If this "contribution-based" analysis indicates that the impact of major source SO_2 emissions on $PM_{2.5}$ exceeds 1.5 µg/m³, then a "sensitivity-based" analysis may be conducted to show that a reduction of SO_2 emissions in the range of 30 – 70% would have only an insignificant impact on lowering $PM_{2.5}$ (also defined as an impact of less than 1.5 µg/m³).
The primary obstacle to conducting a credible SO_2 precursor demonstration for Fairbanks cited by ADEC and EPA results from a combination of two facts:

1. the relatively large contribution of sulfate to total $PM_{2.5}$ mass (approximately 17-18% at the SOB) which results in an ammonium sulfate contribution to $PM_{2.5}$ design value[2] that is well in excess of the "insignificant" concentration threshold (1.5 µg/m³) cited in EPA's precursor demonstration guidance document and which thus implicates the combined impact of major and minor SO_2 sources as significant contributors to peak $PM_{2.5}$ levels; and
2. the large under prediction of sulfate mass by CMAQ for the 2008 episodes (normalized mean bias of -66%)[3] which leads to the conclusion that the current modeling system (consisting of CMAQ and the emissions estimates and meteorological modeling results used as inputs to CMAQ) does not accurately characterize the contributions of SO_2 sources to the $PM_{2.5}$ design value.

In other words, SO_2 sources are observed to contribute significantly to $PM_{2.5}$ nonattainment and the current modeling system is not sufficiently accurate to provide a reliable estimate of the impacts of emission reductions from SO_2 sources. This makes it difficult to develop a precursor attainment

[1] While the 2016 guidance document recommends using 1.3 µg/m3, EPA recently updated and finalized the technical basis document used to set the recommended level and revised the significance threshold to 1.5 µg/m3.

[2] The design value is the pollutant concentration that is compared to the level of the NAAQS. For the 24-hour $PM_{2.5}$ NAAQS, the design value is the annual 98th percentile daily average concentration averaged over three years.

[3] "Addressing the precursor gases for Fairbanks $PM_{2.5}$ State Implementation Plan", D. Huff 9/25/14, Table 1 (p. 125) in Amendments to State Air Quality Control Plan, Vol. II, Sec. D.5, Appendix III.D.5.7.

demonstration for major sources of SO_2 based on the current data and modeling system that otherwise would be considered sufficiently reliable to gain approval by EPA. We note that this also brings into question the reliability of a modeled attainment demonstration that includes SO_2 controls on major sources.

Despite the difficulties noted above with formulating an approvable major source SO_2 precursor demonstration, data analyses and modeling conducted for the Fairbanks moderate area SIP[4] provide some significant information which suggests that in fact major source SO_2 emissions may not contribute significantly to $PM_{2.5}$ nonattainment. We summarize these key results below:

- Analysis of CMAQ model results by UAF show almost no secondary SO_4 production during the modeled periods. Thus, nearly all of the modeled SO_4 is from primary SO_4 emissions.
- CMAQ underpredicted the SO_4 concentration at the SOB by an average of 3.22 µg/m^3 on days with FRM measurements during the 2008 winter episodes (the average observed SO_4 was 5.25 µg/m^3 while the average predicted SO_4 was 2.03 µg/m^3; note that these values are taken from Table 2 of *Amendments to State Air Quality Control Plan, Vol. II, Sec. D.5, Appendix III.D.5.7* and differ slightly from the values in Table 1; we are still trying to determine the reason for these small differences).[5]
- ADEC concluded that there is likely sufficient excess NH_4 present under episode conditions so that reductions of secondary SO_4 would not lead to significant increases in other secondary species such as ammonium nitrate.[6]
- Both CMAQ point source SO_2 "zero out" runs - in which results from the base case CMAQ run are compared with a CMAQ run in which point source SO_2 emissions are reduced to zero - and CALPUFF model runs show that point sources contribute approximately 22% of the total modeled SO_2 from all sources at the SOB monitor with nearly all of the remaining SO_2 coming from heating oil combustion. [7] Note that the modeled point sources consist of the six major SO_2 sources in the nonattainment area.
- CMAQ zero out runs also show that 5% of primary SO_4 is from point sources. The CMAQ SO_4 prediction at SOB is 2.1 µg/m^3 (Table 1) so the modeled point source primary SO_4 contribution is no more than 0.05 * 2.1 = 0.1 µg/m^3.
- Comparisons of total $PM_{2.5}$ mass concentration to the NAAQS are made using data from a Federal Reference Method (FRM) monitor. However, $PM_{2.5}$ species composition data are obtained from a SASS sampler. $PM_{2.5}$ measurements from these two different monitoring methods are not directly comparable due to various unavoidable sampling artifacts. In accordance with EPA guideline procedures, ADEC applied adjustments to the $PM_{2.5}$ species composition data from the SASS sampler at the SOB using the SANDWICH algorithm to more accurately reflect the composition of $PM_{2.5}$ samples collected by the FRM monitor. These adjustments account for differences in the amount of nitrate, ammonium, carbon, other primary $PM_{2.5}$ components (OPP), and particle bound water (PBW) captured by the two instruments.
- For purposes of developing the moderate area SIP, ADEC used the available ambient monitoring data processed through the SANDWICH algorithm to develop a "design day" $PM_{2.5}$ composition representative of the average composition of $PM_{2.5}$ during high wintertime $PM_{2.5}$ episodes. ADEC also calculated the applicable $PM_{2.5}$ "design value" which represents the $PM_{2.5}$ total mass concentration that is compared to the level of the NAAQS. For the moderate area SIP, the $PM_{2.5}$ design value at the

[4] https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-moderate-sip

[5] See Table 2, p. 129 in Amendments to State Air Quality Control Plan, Vol. II, Sec. D.5, Appendix III.D.5.7

[6] Amendments to State Air Quality Control Plan, Vol. II, Sec. D.5, Appendix III.D.5.7, p. 131.

[7] Note that the CALPUFF point source modeling showed that on average only 0.1% of modeled point source SO_2 at SOB during the during Jan. 23rd – Feb 9th 2008 episode days was from the Flint Hills refinery, whereas 36% was from the four power plants and 64% from Ft. Wainwright.

SOB site was determined to be 44.7 µg/m^3. Applying the design day composition to the design value results in the design day $PM_{2.5}$ component concentrations shown in Figure 1.

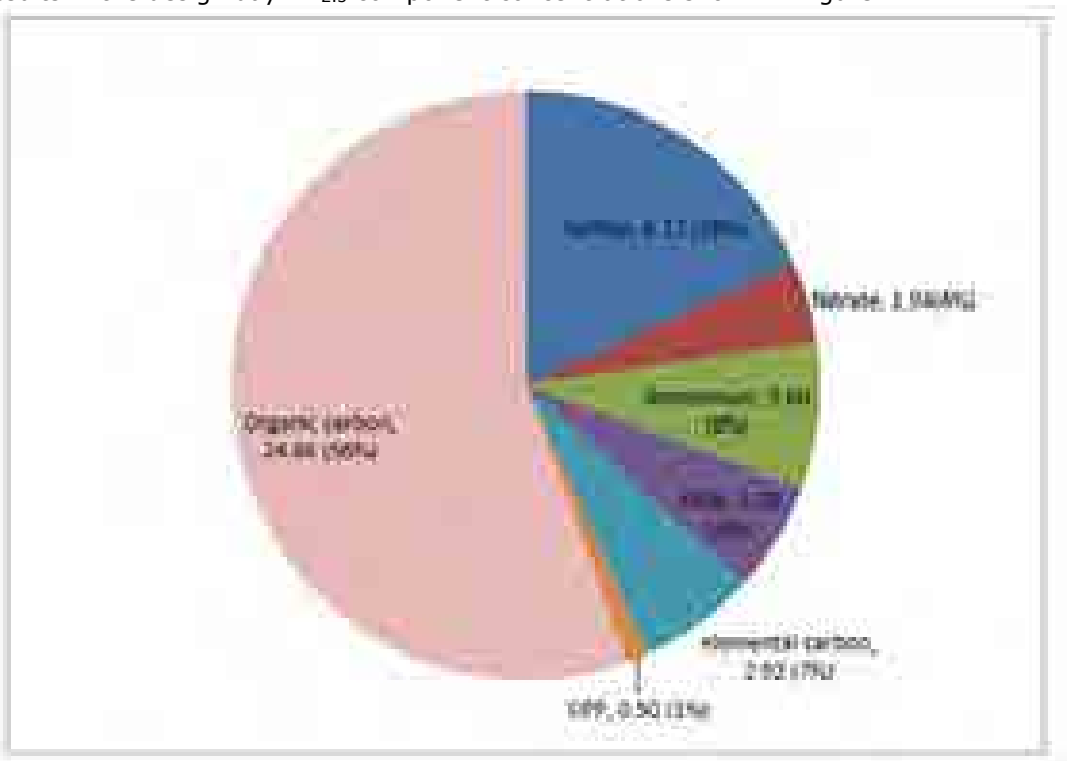


Figure 1. Design day $PM_{2.5}$ speciation at SOB used for the moderate area SIP (source: Appendix III.5.7, p. 122).

- For the design day, the 0.1 µg/m^3 primary sulfate contribution from point sources estimated from the CMAQ zero-out runs noted above scales up to 0.16 µg/m^3 (= 0.1 * 8.17/5.25) where 8.17 µg/m^3 is the amount of SO_4 on the design day and 5.25 µg/m^3 is the average observed amount of SO_4 for the modeled episodes.
- The design day PM composition shown in Figure 1 includes 8.17 µg/m^3 SO_4. The correspondingly scaled SO_4 that is unaccounted for in the CMAQ results is 3.22 * (8.17/5.25) = 5.01 µg/m^3. At one extreme, all of this "unexplained" SO_4 could be attributed to emissions from point sources (i.e., the major SO_2 sources). Perhaps more realistically, one could estimate that 22% of the unexplained SO_4 (0.22 * 5.01 = 1.1 µg/m^3) is from point sources, in keeping with the modeled 22% contribution of point sources to SO_2 noted above. Assuming all SO_4 is in the form of ammonium sulfate, this would be equivalent to a 1.1 * (132/96) = 1.51 µg/m^3 contribution to $PM_{2.5}$, where the factor 132/96 represents the molecular weight ratio of ammonium sulfate to sulfate. Adding to this the amount of particle bound water (PBW) associated with ammonium sulfate assumed in the SANDWICH estimate of FRM measurement (2/3 * 2.70 µg/m^3 = 1.80 µg/m^3 assumed to be associated with 8.17 µg/m^3 of SO_4 so 1.1 µg/m^3 * (1.80/8.17) = 0.24 µg/m^3 of PBW associated with the point source SO_4) results in a total point source ammonium sulfate with associated PBW contribution of 1.51 + 0.24 = 1.75 µg/m^3.
- The above simple "contribution-based" precursor demonstration result indicates that the major source SO_2 contribution is slightly above the "insignificant contribution" threshold (1.5 µg/m^3) cited

in EPA's Precursor Demonstration Guidance. However, the EPA guidance allows for a "sensitivity-based" precursor demonstration in which the reduction in $PM_{2.5}$ concentration resulting from a 30, 50, or 70% reduction in SO_2 emissions is compared to the 1.5 $\mu g/m^3$ significance threshold. Based on a linear extrapolation from the above analysis, a maximum 70% reduction in major source SO_2 emissions would be expected to produce a 1.23 $\mu g/m^3$ decrease in $PM_{2.5}$, which is below the 1.5 $\mu g/m^3$ significance threshold. In other words, the $PM_{2.5}$ design value is relatively insensitive to even a large (70%) reduction in major source SO_2 emissions.

Although the above result for a sensitivity-based SO_2 precursor demonstration is encouraging, it must be noted that the precursor demonstration guideline suggests that ADEC may still need to include consideration of the feasibility of major source SO_2 reduction measures in its SIP, even if the sensitivity-based demonstration produces a result below the significance threshold. This may be particularly important for Fairbanks given uncertainties about the amount of SO_4 actually contributed by the major sources.

It is also important to keep in mind that conditions have changed in Fairbanks since 2008 and the new Serious area SIP will use a base year of 2013 to represent "current conditions". Updated area source emissions will be modeled but episodic point source emissions will be based on the 2008 point source inventory. Modeling results are not yet available, so it is not possible to know how the above results might differ for the new base year.

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Run Summaries

Analysis Results for 1 Date(s) 12-11-15

Customer	Date	#Cars	BTU	Ash20	%A	%M	%C	%S	Size	Bench	Seam	Form
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Run Summary

Analytical Results for 2 Samples as of 11:34

Mine Inspection

Inspection Activity: 12/2/14 to 12/2/14

| | | |

Run Sample

Analyzed: [illegible]

[illegible]													
[illegible]													
[illegible]													
[illegible]													
[illegible]													
[illegible]													
[illegible]													
[illegible]													
[illegible]													

[illegible] Analysis Summary

[illegible]													

[illegible]

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/15 to 6/30/15

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	1/2/2015	10	7642	28.10	8.76	35.14	27.98	0.32	BeWD	G	4/4	913.35
AURORA ENERGY LLC	1/5/2015	6	7586	29.30	7.87	34.51	28.33	0.31	BeWD	G	4/4	781.99
AURORA ENERGY LLC	1/6/2015	15	7583	29.68	7.16	34.84	28.32	0.31	BeWD	G	4/4	1,331.30
AURORA ENERGY LLC	1/7/2015	10	7599	29.58	6.82	34.57	28.74	0.19	BeWD	G	4/4	913.10
AURORA ENERGY LLC	1/8/2015	13	7572	27.19	9.56	35.09	28.15	0.24	BeWD	G	4/4	1,217.90
AURORA ENERGY LLC	1/9/2015	13	7558	28.59	7.66	35.84	28.04	0.20	BeWD	G	4/4	1,270.68
AURORA ENERGY LLC	1/12/2015	8	7612	27.14	8.36	35.22	28.24	0.29	BeWT II	G/LST	4/4	735.78
AURORA ENERGY LLC	1/13/2015	13	7606	27.86	8.81	35.00	28.33	0.21	BeWT II	G/LST	4/4	1,349.40
AURORA ENERGY LLC	1/14/2015	30	7329	26.04	13.53	34.27	27.67	0.31	BeWTK	G	4/4	2,906.30
AURORA ENERGY LLC	1/14/2015	10	7415	28.77	11.28	34.53	27.42	0.30	BeWTK	G	4/4	985.30
AURORA ENERGY LLC	1/16/2015	8	7722	27.68	7.86	35.65	28.80	0.15	BeWTK	G	4/4	710.60
AURORA ENERGY LLC	1/20/2015	13	7616	28.20	7.93	36.17	27.71	0.15	TWTK	LST	4/4	1,225.25
AURORA ENERGY LLC	1/21/2015	10	7490	27.57	9.57	36.02	26.73	0.14	T II	LST	4	994.30
AURORA ENERGY LLC	1/22/2015	8	7626	27.39	8.88	35.40	28.28	0.22	BeWTK	G	4/4	778.30
AURORA ENERGY LLC	1/26/2015	9	7609	27.97	7.73	35.95	28.26	0.15	BeWT II	F/LST	3/4	835.50
AURORA ENERGY LLC	1/27/2015	7	7515	28.16	8.81	36.22	26.68	0.14	T II	LST	4	648.20
AURORA ENERGY LLC	1/28/2015	5	7488	28.31	9.15	36.15	26.41	0.15	T II	LST	4	445.45
AURORA ENERGY LLC	1/29/2015	8	7515	28.38	8.44	39.83	26.56	0.13	TII	LST	4	554.05
AURORA ENERGY LLC	1/29/2015	5	7607	28.09	8.04	36.66	27.05	0.13	TII	LST	4	424.60
AURORA ENERGY LLC	1/30/2015	14	7541	28.03	8.44	37.02	26.22	0.13	TII	LST	4	1,309.20
AURORA ENERGY LLC	2/2/2015	9	7561	28.26	8.55	36.53	26.67	0.14	TII	LST	4	834.90
AURORA ENERGY LLC	2/3/2015	31	7378	28.44	12.14	34.70	24.75	0.15	T II	LST	4	2,859.90
AURORA ENERGY LLC	2/3/2015	11	7598	27.65	12.68	35.06	24.52	0.14	T II	LST	4	969.60
AURORA ENERGY LLC	2/4/2015	12	7565	28.09	12.16	34.82	25.30	0.15	T II	LST	4	1,126.45
AURORA ENERGY LLC	2/9/2015	8	7620	27.91	7.78	35.30	29.02	0.13	BeWD	F	3/4	742.75
AURORA ENERGY LLC	2/10/2015	14	7617	27.82	5.86	35.20	30.48	0.13	BeWD	F	3/4	1,277.15
AURORA ENERGY LLC	2/11/2015	8	7700	28.03	6.64	35.35	29.02	0.12	BeWD	F	3/4	680.85
AURORA ENERGY LLC	2/12/2015	6	7618	28.59	7.58	35.86	27.84	0.12	BeWD	F	3/4	525.70
AURORA ENERGY LLC	2/13/2015	8	7516	28.80	7.11	36.07	27.73	0.12	BeWD	F	3/4	674.15
AURORA ENERGY LLC	2/16/2015	8	7651	29.89	6.49	35.97	27.74	0.11	T WD	LST	3/4	716.15

Rail Samples

Analysis Results for 1/1/15 to 6/30/15

AURORA ENERGY LLC	2/17/2015	10	7648	30.40	6.24	36.60	27.71	0.12	JD		4	871.10
AURORA ENERGY LLC	2/18/2015	6	7411	30.60	6.97	34.94	27.37	0.13	T WJD	LST	6/4	775.50
AURORA ENERGY LLC	2/19/2015	10	7474	29.89	7.47	36.13	28.08	0.12	JD/T 6	LST	4/6	950.10
AURORA ENERGY LLC	2/20/2015	13	7656	32.19	6.69	36.82	28.35	0.12	T WJD	LST	6/4	1,067.70
AURORA ENERGY LLC	2/23/2015	6	7490	30.69	6.82	35.48	27.09	0.13	T WJD	LST	6/4	156.30
AURORA ENERGY LLC	2/24/2015	11	7570	29.59	7.24	35.96	27.72	0.14	JD/T3	LST	4/6	975.90
AURORA ENERGY LLC	2/25/2015	11	7581	29.41	7.42	35.83	27.26	0.13	T WJD	LST	6/4	1,033.89
AURORA ENERGY LLC	2/26/2015	11	7582	29.74	6.75	36.28	27.23	0.12	T WJD	LST	6/4	1,303.80
AURORA ENERGY LLC	2/27/2015	13	7566	29.97	6.61	36.58	27.37	0.12	TWJD	LST	6/4	1,039.80
AURORA ENERGY LLC	3/2/2015	6	7521	29.92	6.43	36.02	27.64	0.12	TWJD	LST	6/4	730.50
AURORA ENERGY LLC	3/3/2015	10	7559	29.84	6.91	36.58	27.67	0.11	TWJD	LST	6/4	910.50
AURORA ENERGY LLC	3/4/2015	4	7547	30.62	6.24	36.70	27.24	0.11	TWJD	LST	6/4	356.16
AURORA ENERGY LLC	3/5/2015	10	7705	29.51	6.01	36.39	28.13	0.11	TWJD	LST	6/4	627.45
AURORA ENERGY LLC	3/6/2015	11	7663	30.66	5.49	36.26	27.60	0.11	TWJD	LST	6/4	1,032.05
AURORA ENERGY LLC	3/10/2015	6	7505	30.34	6.76	36.30	28.00	0.11	TWJD	LST	6/4	549.72
AURORA ENERGY LLC	3/11/2015	28	7109	31.44	7.90	34.88	25.76	0.10	TWJD	LST	6/4	3,416.96
AURORA ENERGY LLC	3/12/2015	7	7483	29.94	7.34	35.71	27.02	0.11	TWJD	LST	6/4	620.16
AURORA ENERGY LLC	3/16/2015	9	7529	29.76	7.33	35.66	27.09	0.14	TWJD	LST	6/4	870.18
AURORA ENERGY LLC	3/17/2015	5	7468	30.08	7.36	35.59	26.98	0.11	TWJD	LST	6/4	463.20
AURORA ENERGY LLC	3/18/2015	13	7548	30.21	6.84	35.43	27.65	0.13	TWJD	LST	6/4	1,088.88
AURORA ENERGY LLC	3/19/2015	12	7548	29.60	7.58	35.96	26.88	0.14	TWJD	LST	6/4	1,705.19
AURORA ENERGY LLC	3/20/2015	7	7620	29.93	7.00	36.02	27.06	0.12	TWJD	LST	6/4	880.20
AURORA ENERGY LLC	3/23/2015	5	7569	29.59	6.89	35.39	27.26	0.12	TWJD	LST	6/4	493.55
AURORA ENERGY LLC	4/2/2015	7	7727	30.71	5.56	35.06	28.04	0.12	JD		4	841.68
AURORA ENERGY LLC	4/6/2015	10	7763	31.23	4.81	35.16	28.15	0.11	JD		4	958.40
AURORA ENERGY LLC	4/7/2015	13	7826	30.95	4.55	35.57	28.93	0.11	JD		4	1,091.38
AURORA ENERGY LLC	4/8/2015	11	7669	31.37	5.38	34.69	28.71	0.11	JD		4	1,022.50
AURORA ENERGY LLC	4/9/2015	13	7581	31.87	5.38	34.94	28.14	0.12	JD		4	1,161.20
AURORA ENERGY LLC	4/10/2015	7	7716	30.74	5.65	35.79	28.84	0.11	JD		4	660.99
AURORA ENERGY LLC	4/13/2015	9	7711	31.37	4.82	34.74	28.07	0.11	JD		4	798.29
AURORA ENERGY LLC	4/14/2015	13	7716	31.37	4.77	35.37	28.65	0.11	JD		4	1,108.30
AURORA ENERGY LLC	4/20/2015	6	7628	30.63	5.98	34.98	28.82	0.09	JD		4	858.00

Rail Samples

Analysis Results for 1/1/15 to 6/30/15

AURORA ENERGY LLC	4/21/2015	11	7544	30.03	7.59	33.80	28.86	0.11	JD		A	886.36
AURORA ENERGY LLC	4/22/2015	8	7626	29.64	7.22	34.33	29.81	0.14	BelUD	G	419	788.10
AURORA ENERGY LLC	4/27/2015	8	7681	29.30	5.26	35.34	30.09	0.11	JDRail	G	423	748.76
AURORA ENERGY LLC	4/28/2015	10	7653	29.01	5.21	35.73	30.09	0.11	BelUD	G	314	803.79
AURORA ENERGY LLC	4/29/2015	10	7620	31.74	4.50	35.10	28.91	0.10	JD		A	804.96
AURORA ENERGY LLC	4/30/2015	12	7648	29.84	7.39	34.53	29.28	0.11	BelUD	G	314	1,151.99
AURORA ENERGY LLC	5/1/2015	8	7453	31.00	6.78	34.90	27.73	0.10	JD		A	733.99
AURORA ENERGY LLC	5/4/2015	10	7494	31.57	6.35	34.12	27.97	0.13	JD		A	881.35
AURORA ENERGY LLC	5/5/2015	8	7414	31.83	6.59	35.56	27.91	0.11	JD		A	747.58
AURORA ENERGY LLC	5/6/2015	11	7610	30.24	6.28	34.87	28.62	0.11	BelUD	G	314	880.55
AURORA ENERGY LLC	5/7/2015	8	7511	31.23	6.19	34.66	28.09	0.11	JD		A	873.00
AURORA ENERGY LLC	5/8/2015	8	7743	29.92	5.84	35.21	28.94	0.12	JD		A	704.65
AURORA ENERGY LLC	5/12/2015	16	7655	29.79	6.48	35.58	28.22	0.11	JD		A	1,411.60
AURORA ENERGY LLC	5/15/2015	16	7535	29.73	7.55	35.02	27.76	0.12	BelUD	G	314	1,361.45
AURORA ENERGY LLC	5/14/2015	1	7555	30.39	6.72	34.68	28.06	0.11	JD		A	99.68
AURORA ENERGY LLC	5/18/2015	13	7707	29.87	6.36	35.17	28.58	0.11	JD		A	1,293.68
AURORA ENERGY LLC	5/19/2015	8	7694	30.15	6.19	34.79	28.88	0.11	JD		A	704.35
AURORA ENERGY LLC	5/20/2015	12	7626	30.39	6.23	34.90	28.38	0.12	JD		A	1,155.60
AURORA ENERGY LLC	5/21/2015	12	7494	31.30	6.36	34.44	27.88	0.11	JD		A	1,157.48
AURORA ENERGY LLC	5/23/2015	18	7705	29.91	6.19	35.48	28.89	0.11	JD		A	1,660.70
AURORA ENERGY LLC	5/26/2015	8	7560	29.85	7.16	34.99	28.09	0.12	JD		A	732.30
AURORA ENERGY LLC	5/27/2015	14	7555	29.81	7.56	35.32	28.52	0.12	JD		A	1,276.90
AURORA ENERGY LLC	5/28/2015	14	7626	29.63	6.99	34.90	28.48	0.12	JD		A	1,353.00
AURORA ENERGY LLC	5/29/2015	6	7579	30.41	6.82	34.96	28.11	0.13	JD		A	565.26
AURORA ENERGY LLC	6/1/2015	8	7636	30.23	6.19	35.13	28.44	0.12	JD		A	687.76
AURORA ENERGY LLC	6/2/2015	8	7728	31.20	4.73	35.04	28.66	0.12	JD		A	727.00
AURORA ENERGY LLC	6/3/2015	12	7647	31.19	6.61	33.90	28.44	0.12	JD		A	1,106.66
AURORA ENERGY LLC	6/4/2015	13	7702	30.18	5.50	34.98	28.39	0.12	JD		A	1,262.20
AURORA ENERGY LLC	6/5/2015	13	7703	30.84	5.14	35.49	28.48	0.11	JD		A	1,158.15
AURORA ENERGY LLC	6/8/2015	10	7842	30.81	4.60	35.17	28.53	0.11	JD		A	944.18
AURORA ENERGY LLC	6/9/2015	8	7720	30.82	5.51	34.59	28.03	0.12	JD		A	772.99
AURORA ENERGY LLC	6/10/2015	8	7794	30.39	4.84	35.61	28.16	0.12	JD		A	865.10

Usibelli Coal Mine

Reil Samples

Analysis Results for 1/1/15 to 6/30/15

AURORA ENERGY LLC	6/11/2015	3	7852	26.43	6.93	34.72	29.93	0.12	GRP/STK		MIN	184.00
AURORA ENERGY LLC	6/12/2015	11	7856	28.22	7.74	34.69	29.34	0.14	GRP/STK		MIN	1,098.10
AURORA ENERGY LLC	6/15/2015	10	7900	26.59	8.73	35.53	28.95	0.14	GRP/STK		MIN	896.05
AURORA ENERGY LLC	6/16/2015	8	7887	25.37	10.64	35.36	28.73	0.15	GRP/STK		MIN	568.88
AURORA ENERGY LLC	6/17/2015	28	7928	24.32	14.26	34.44	26.98	0.15	GRP/STK		MIN	2,432.66
AURORA ENERGY LLC	6/17/2015	9	7918	24.53	13.91	35.06	26.61	0.15	GRP/STK		MIN	866.63
AURORA ENERGY LLC	6/22/2015	10	7848	28.27	8.58	35.13	28.02	0.13	JD		4	975.50
AURORA ENERGY LLC	6/23/2015	12	7881	28.39	8.07	34.39	29.15	0.13	Bot		4	1,166.10
AURORA ENERGY LLC	6/24/2015	8	7885	27.12	7.72	35.35	29.83	0.13	Bot/STK		SIN	661.60
AURORA ENERGY LLC	6/25/2015	8	7913	27.83	6.86	35.50	29.82	0.11	Bot/STK	I	SIN	548.68
AURORA ENERGY LLC	6/26/2015	10	8048	28.16	8.73	35.21	28.87	0.15	GRP/STK		MIN	959.89
AURORA ENERGY LLC	6/29/2015	14	8027	26.68	8.73	34.64	29.93	0.13	GRP/STK		MIN	1,380.95
AURORA ENERGY LLC	6/30/2015	14	7934	27.67	7.68	35.04	29.11	0.14	JD		4	1,330.30

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	103504.80	7899.00	29.16	7.65	35.23	27.96	0.14

This analysis is representative of the coal shipped. The sulfur content in this shipment was analyzed using sulfur standard ASTM D4239.

Coleen Thompson Date 7-1-15

Coleen Thompson

Signature

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/15 to 12/31/15

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	7/2/2015	9	7688	29.37	7.19	36.30	28.31	0.13	Bld/GRP	I	3/4	997.30
AURORA ENERGY LLC	7/6/2015	16	7826	28.59	7.82	36.01	28.48	0.19	Bld	I	4	1,372.10
AURORA ENERGY LLC	7/7/2015	14	7874	28.56	7.79	36.94	28.71	0.21	Bld	I	4	1,382.00
AURORA ENERGY LLC	7/8/2015	3	7868	28.43	7.83	36.21	29.54	0.21	BLD	I	4	319.65
AURORA ENERGY LLC	7/9/2015	5	7719	28.23	8.84	35.58	28.25	0.22	Bld	I	4	780.95
AURORA ENERGY LLC	7/10/2015	5	7821	29.96	8.00	36.79	29.33	0.19	Bld	I	4	809.65
AURORA ENERGY LLC	7/13/2015	10	7821	28.78	7.87	36.61	29.47	0.19	Bld	I	4	979.25
AURORA ENERGY LLC	7/14/2015	10	7750	28.64	8.53	36.28	28.56	0.21	Bld	I	4	954.80
AURORA ENERGY LLC	7/15/2015	10	7857	28.78	7.84	36.58	29.13	0.21	Bld	I	4	982.55
AURORA ENERGY LLC	7/16/2015	15	7869	28.59	7.59	36.92	28.95	0.21	Bld	I	4	1,462.70
AURORA ENERGY LLC	7/17/2015	8	7833	26.21	7.83	37.22	28.75	0.22	Bld	I	4	769.40
AURORA ENERGY LLC	7/20/2015	9	7880	27.03	7.13	36.27	29.55	0.19	Bld	I	4	799.55
AURORA ENERGY LLC	7/21/2015	8	7894	27.61	7.66	35.51	28.83	0.20	Bld/GRP	I	4/5	809.20
AURORA ENERGY LLC	7/22/2015	9	7857	28.32	8.09	35.51	28.72	0.19	JD		4	877.65
AURORA ENERGY LLC	7/23/2015	6	7439	35.33	7.55	34.18	27.50	0.12	JD		4	659.90
AURORA ENERGY LLC	7/24/2015	6	7628	29.90	8.48	35.20	28.36	0.11	JD		4	772.45
AURORA ENERGY LLC	7/27/2015	9	7432	31.12	7.98	33.81	27.70	0.13	JD		4	999.50
AURORA ENERGY LLC	7/28/2015	11	7523	30.83	8.76	34.27	28.14	0.12	JD		4	1,073.20
AURORA ENERGY LLC	7/29/2015	7	7429	30.34	7.77	34.16	27.79	0.14	JD		4	693.65
AURORA ENERGY LLC	7/31/2015	8	7734	27.22	7.93	35.80	28.86	0.22	Bld/Bld	R	3/4	724.30
AURORA ENERGY LLC	8/3/2015	9	7654	28.46	7.69	35.42	28.41	0.16	JD		4	897.75
AURORA ENERGY LLC	8/4/2015	10	7570	29.61	8.73	35.30	28.57	0.14	JD		4	937.50
AURORA ENERGY LLC	8/5/2015	12	7569	30.37	8.87	35.07	27.90	0.13	JD		4	999.75
AURORA ENERGY LLC	8/6/2015	11	7579	30.39	8.11	34.22	28.33	0.16	JD		4	1,037.80
AURORA ENERGY LLC	8/7/2015	11	7588	30.17	8.21	34.59	27.43	0.16	Bld/JD	I	4/5	1,056.30
AURORA ENERGY LLC	8/10/2015	18	7665	29.39	8.76	35.20	28.55	0.15	JD/Bld	II	4/5	1,553.75
AURORA ENERGY LLC	8/12/2015	18	7369	31.58	7.10	33.84	27.40	0.14	JD		4	1,418.85
AURORA ENERGY LLC	8/13/2015	18	7510	30.41	8.75	34.63	28.16	0.17	Bld/JD	I	4/5	1,775.95
AURORA ENERGY LLC	8/14/2015	15	7723	27.83	7.28	35.00	28.82	0.14	Bld	I	4	1,297.60
AURORA ENERGY LLC	8/17/2015	10	7663	29.07	7.20	35.81	28.75	0.15	JD		4	943.85

Rail Samples

Analysis Results for 7/1/15 to 12/31/15

AURORA ENERGY LLC	8/18/2015	13	7658	28.60	7.01	35.59	28.76	0.16	JD			4	1,365.45
AURORA ENERGY LLC	8/20/2015	15	7311	31.47	7.31	33.83	27.39	0.13	BdrJD	P		3H	1,286.75
AURORA ENERGY LLC	8/22/2015	18	7584	31.73	8.05	34.30	27.83	0.10	JD			4	1,348.75
AURORA ENERGY LLC	8/26/2015	16	7740	26.52	8.85	34.07	28.56	0.17	JDrDRP			4M	1,471.40
AURORA ENERGY LLC	8/28/2015	3	7642	28.09	8.57	35.46	27.94	0.15	DPRBd			WE	281.90
AURORA ENERGY LLC	8/31/2015	8	7628	27.35	8.56	36.33	27.37	0.14	Bd			8	720.59
AURORA ENERGY LLC	9/1/2015	11	7681	27.34	9.24	35.84	27.43	0.13	Bd			8	1,051.19
AURORA ENERGY LLC	9/2/2015	19	7663	27.07	9.34	36.01	27.09	0.14	Bd			8	1,908.00
AURORA ENERGY LLC	9/3/2015	27	7665	27.90	8.27	35.87	28.31	0.13	Bd			8	2,699.55
AURORA ENERGY LLC	9/8/2015	17	7606	27.39	7.48	35.84	29.81	0.13	BdrSTK			3N	1,094.55
AURORA ENERGY LLC	9/10/2015	20	7661	28.55	7.71	35.76	29.97	0.14	BdrRP			3M	1,353.50
AURORA ENERGY LLC	9/11/2015	21	7710	29.65	8.21	35.52	28.61	0.14	BdrDRP			3M	1,974.90
AURORA ENERGY LLC	9/15/2015	18	7420	26.03	13.40	33.43	27.10	0.16	BdrDRP			3M	1,735.35
AURORA ENERGY LLC	9/16/2015	17	7697	26.35	10.77	36.52	26.56	0.16	DRPBd			MR	1,681.25
AURORA ENERGY LLC	9/17/2015	17	7519	26.86	10.96	35.61	26.59	0.16	BdrDRP			8M	1,165.50
AURORA ENERGY LLC	9/22/2015	16	7186	27.11	13.93	34.58	25.86	0.17	BdrDRP			8M	1,877.20
AURORA ENERGY LLC	9/23/2015	18	7544	27.46	8.16	34.44	28.34	0.16	Bdr			3	1,812.45
AURORA ENERGY LLC	9/24/2015	9	7573	26.47	10.48	34.19	28.86	0.14	Bdr			3	804.35
AURORA ENERGY LLC	9/29/2015	8	7141	28.88	11.36	33.89	25.87	0.15	BdrDRP			3M	809.55
AURORA ENERGY LLC	9/30/2015	6	7514	28.44	8.69	34.21	28.66	0.12	BdrBd			3R	492.90
AURORA ENERGY LLC	10/1/2015	10	7360	29.29	8.56	33.75	27.94	0.14	BdrBd			3R	949.70
AURORA ENERGY LLC	10/5/2015	17	7434	28.25	8.47	34.75	27.54	0.14	Bdr			8	1,897.50
AURORA ENERGY LLC	10/7/2015	18	7427	28.14	8.75	33.79	28.48	0.13	BdrSTK			3N	1,600.50
AURORA ENERGY LLC	10/8/2015	18	7706	28.02	8.97	35.04	28.97	0.14	BdrSTK			3N	1,650.30
AURORA ENERGY LLC	10/12/2015	12	7609	28.74	8.47	34.02	28.77	0.11	BdrJD			3H	1,186.55
AURORA ENERGY LLC	10/13/2015	14	7448	29.48	8.57	34.10	27.88	0.11	BdrJD			3H	1,370.00
AURORA ENERGY LLC	10/14/2015	15	7329	31.93	7.28	33.16	27.63	0.11	BdrJD			3H	1,487.55
AURORA ENERGY LLC	10/15/2015	5	7435	31.85	8.81	34.31	27.23	0.11	JD			4	472.55
AURORA ENERGY LLC	10/16/2015	9	7723	31.39	9.10	35.54	26.17	0.11	JD			4	864.60
AURORA ENERGY LLC	10/20/2015	16	7561	31.39	8.82	34.71	27.39	0.11	JD			4	1,440.22
AURORA ENERGY LLC	10/21/2015	14	7609	31.67	8.47	34.54	28.22	0.11	JD			4	1,346.70
AURORA ENERGY LLC	10/22/2015	13	7482	33.01	9.01	34.28	27.70	0.11	JD			4	1,364.40

Rail Samples

Analysis Results for 1/1/15 to 12/31/15

AURORA ENERGY LLC	10/03/2015	15	7347	32.39	6.71	33.48	27.42	0.12	JD		4	1,482.30
AURORA ENERGY LLC	10/07/2015	9	7404	30.15	6.49	34.36	27.00	0.19	BdJ	J	4	910.80
AURORA ENERGY LLC	10/28/2015	11	7586	30.33	6.73	36.02	27.93	0.14	BdJJD	JP	4/4	1,018.80
AURORA ENERGY LLC	10/29/2015	9	7661	26.44	7.92	36.66	29.99	0.19	BdJ	J	4	822.60
AURORA ENERGY LLC	10/30/2015	11	7648	26.99	7.60	36.80	28.19	0.17	BdJ	J	4	1,070.45
AURORA ENERGY LLC	11/02/2015	10	7408	27.87	10.34	34.89	27.29	0.28	BdJJD	JJ	4/4	894.40
AURORA ENERGY LLC	11/4/2015	10	7483	28.07	8.21	34.19	27.93	0.22	BdJ	J	4	1,577.40
AURORA ENERGY LLC	11/5/2015	11	7320	29.87	8.27	33.61	27.46	0.22	BdJ	J	4	1,552.25
AURORA ENERGY LLC	11/6/2015	12	7626	27.60	8.75	35.23	28.42	0.23	BdJJD	JP	4/4	1,179.00
AURORA ENERGY LLC	11/10/2015	12	7640	28.50	7.97	35.23	28.29	0.19	BdJ	J	4	1,130.28
AURORA ENERGY LLC	11/11/2015	14	7665	27.22	7.56	35.71	28.58	0.21	BdJ	J	4	1,331.08
AURORA ENERGY LLC	11/12/2015	12	7797	27.26	7.73	35.48	28.54	0.23	BdJ	J	4	1,148.58
AURORA ENERGY LLC	11/13/2015	14	7847	28.11	7.79	36.51	29.00	0.19	BdJ	J	4	1,368.90
AURORA ENERGY LLC	11/17/2015	9	7760	27.53	7.86	35.47	29.14	0.20	BdJJD	JP	4/4	849.40
AURORA ENERGY LLC	11/18/2015	11	7700	28.28	7.44	35.64	28.55	0.18	BdJJD	J	4/4	1,006.00
AURORA ENERGY LLC	11/19/2015	8	7844	30.76	8.20	34.89	28.13	0.19	BdJJD	J	4/4	714.88
AURORA ENERGY LLC	11/20/2015	10	7783	28.27	8.29	35.76	28.73	0.19	JDBdJ	JJ	4/4	885.55
AURORA ENERGY LLC	11/23/2015	11	7793	29.30	8.29	35.57	28.79	0.19	JD		4	1,046.45
AURORA ENERGY LLC	11/24/2015	16	7582	30.62	6.97	34.82	28.69	0.12	JD		4	1,519.90
AURORA ENERGY LLC	11/25/2015	13	7770	28.64	8.19	35.63	28.69	0.19	JDBdJ	JJ	4/4	1,300.89
AURORA ENERGY LLC	11/27/2015	12	7812	28.41	7.98	35.69	27.84	0.19	BdJSTK	JP	4/4	1,176.60
AURORA ENERGY LLC	12/1/2015	21	7814	29.25	8.35	34.58	27.83	0.29	BdJSTK	JP	4/4	1,977.15
AURORA ENERGY LLC	12/2/2015	9	7687	30.48	6.72	34.32	28.69	0.16	JD		4	824.10
AURORA ENERGY LLC	12/3/2015	13	7677	30.45	4.74	33.98	28.84	0.10	JD		4	1,097.46
AURORA ENERGY LLC	12/4/2015	10	7603	31.28	6.60	33.78	28.36	0.12	JD		4	819.25
AURORA ENERGY LLC	12/8/2015	13	7694	29.65	7.36	34.63	28.47	0.17	BdJJD	JP	4/4	1,204.60
AURORA ENERGY LLC	12/9/2015	13	7827	28.50	8.21	34.71	28.58	0.20	BdJJD	JP	4/4	1,294.85
AURORA ENERGY LLC	12/10/2015	12	7851	29.18	7.10	35.18	28.55	0.17	BdJJD	JP	4/4	1,200.15
AURORA ENERGY LLC	12/11/2015	10	7159	33.74	6.25	34.17	25.84	0.14	JD		4	935.55
AURORA ENERGY LLC	12/15/2015	14	7693	31.16	5.91	35.16	27.78	0.19	BdJJD	J	4/4	1,236.25
AURORA ENERGY LLC	12/16/2015	14	7627	31.79	6.00	35.00	27.27	0.18	BdJJD	J	4/4	1,288.80
AURORA ENERGY LLC	12/17/2015	14	7838	29.85	6.85	35.24	28.12	0.19	BdJJD	J	4/4	1,258.55

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/15 to 12/31/15

AURORA ENERGY LLC	12/15/2015	14	7871	30.88	6.56	34.75	28.55	0.13	BtuUD	J	414	5,314.65
AURORA ENERGY LLC	12/21/2015	14	7833	30.24	6.30	35.11	28.29	0.15	BtuUD	J	414	5,318.90
AURORA ENERGY LLC	12/22/2015	14	7549	31.16	8.71	34.71	28.39	0.13	BtuUD	J	414	5,250.66
AURORA ENERGY LLC	12/23/2015	14	7686	31.42	4.63	36.27	28.66	0.10	BtuUD	J	414	5,362.70
AURORA ENERGY LLC	12/24/2015	10	7827	31.52	4.82	35.84	27.89	0.11	BtuUD	J	414	933.25
AURORA ENERGY LLC	12/28/2015	14	7714	30.71	4.89	36.51	28.36	0.11	BtuUD	J	414	5,249.48
AURORA ENERGY LLC	12/29/2015	16	7780	30.58	5.61	35.97	28.95	0.12	BtuUD	J	414	1,434.70
AURORA ENERGY LLC	12/30/2015	11	7873	31.40	5.02	35.84	27.95	0.12	BtuUD	J	414	856.20
AURORA ENERGY LLC	12/31/2015	12	7705	31.63	4.47	35.87	28.34	0.12	BtuUD	J	414	1,059.70

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	120798.30	7810.00	29.02	7.69	35.00	28.20	0.13

This analysis is representative of the coal shipped. The sulfur content in this shipment was analyzed using sulfur standard ASTM D4239.

Colleen Thompson **Date** 1-7-16

Colleen Thompson

Signature

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Kiril Samples

Analysis Results for 1/1/16 to 6/30/16

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	1/6/2016	12	7673	31.19	4.92	35.32	28.59	0.11	BBWJD	J	4/4	1,108.40
AURORA ENERGY LLC	1/8/2016	14	7682	32.31	4.30	34.88	28.69	0.11	JD		4	1,247.50
AURORA ENERGY LLC	1/7/2016	14	7643	32.55	3.60	35.28	28.78	0.09	JD		4	1,202.85
AURORA ENERGY LLC	1/8/2016	12	7797	31.14	4.23	36.17	28.47	0.11	JD		4	1,070.90
AURORA ENERGY LLC	1/12/2016	13	7681	32.21	4.49	35.14	28.23	0.11	BBWJD	J	4/4	1,206.75
AURORA ENERGY LLC	1/13/2016	18	7628	32.40	4.12	35.32	28.19	0.09	JD		4	1,613.00
AURORA ENERGY LLC	1/14/2016	14	7658	28.18	6.49	37.67	29.68	0.11	JD		4	1,188.40
AURORA ENERGY LLC	1/15/2016	16	7789	31.38	4.12	36.77	27.79	0.11	JD		4	1,385.20
AURORA ENERGY LLC	1/18/2016	18	7765	31.50	4.28	36.27	28.87	0.10	JD		4	1,654.95
AURORA ENERGY LLC	1/20/2016	16	7643	31.19	5.24	35.69	28.05	0.12	JD		4	1,439.05
AURORA ENERGY LLC	1/21/2016	15	7788	31.49	4.40	35.39	28.71	0.12	JD		4	1,348.89
AURORA ENERGY LLC	1/22/2016	22	7741	31.09	4.82	35.72	28.56	0.11	JD		4	1,982.55
AURORA ENERGY LLC	1/25/2016	14	7616	32.12	5.10	34.25	27.54	0.13	JD		4	1,260.60
AURORA ENERGY LLC	1/27/2016	12	7664	31.19	5.07	35.10	28.66	0.11	BBWJD	J	4/4	1,085.55
AURORA ENERGY LLC	1/28/2016	11	7741	31.54	4.52	35.18	28.79	0.10	BBWJD	J	4/4	982.55
AURORA ENERGY LLC	1/29/2016	13	7648	31.30	4.34	35.68	28.98	0.10	JD		4	1,140.40
AURORA ENERGY LLC	2/2/2016	12	7588	31.55	5.24	34.87	28.38	0.10	JD/BB	U	4/3	1,088.10
AURORA ENERGY LLC	2/3/2016	13	7688	31.32	4.76	35.02	28.82	0.12	BBWJD	J	4/4	1,202.80
AURORA ENERGY LLC	2/4/2016	8	7548	30.72	6.68	34.43	27.96	0.16	BBWJD	J	4/4	705.70
AURORA ENERGY LLC	2/5/2016	11	7654	30.62	5.68	35.22	28.31	0.14	JD/BB	U	4/4	998.75
AURORA ENERGY LLC	2/8/2016	14	7570	31.36	5.21	34.69	27.88	0.13	JD		4	1,298.30
AURORA ENERGY LLC	2/10/2016	13	7789	29.54	5.19	35.85	28.85	0.15	BBWJD	J	4/4	1,191.49
AURORA ENERGY LLC	2/11/2016	11	7478	31.67	5.48	34.93	27.83	0.16	BBWJD	J	4/4	1,023.69
AURORA ENERGY LLC	2/12/2016	15	7576	30.68	5.58	35.74	28.58	0.14	BBWJD	J	4/4	1,417.39
AURORA ENERGY LLC	2/16/2016	16	7634	30.60	5.36	36.05	27.93	0.14	JD/Bull	U	4/4	1,512.75
AURORA ENERGY LLC	2/17/2016	14	7781	29.69	5.73	35.79	28.79	0.17	BBWJD	J	4/4	1,289.10
AURORA ENERGY LLC	2/18/2016	11	7773	30.30	5.11	35.38	28.89	0.14	BBWJD	J	4/4	1,016.45
AURORA ENERGY LLC	2/19/2016	16	7658	29.61	5.48	36.18	28.96	0.14	JD/Bull	U	4/4	1,465.95
AURORA ENERGY LLC	2/22/2016	21	7606	29.40	4.93	36.36	29.21	0.14	JD		4	1,903.36

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/18 to 6/30/18

AURORA ENERGY LLC	3/24/2018	16	7799	31.52	4.31	35.55	28.89	0.12	BdDJD	J	444	1,498.15
AURORA ENERGY LLC	3/25/2018	15	7784	31.56	4.13	35.15	29.23	0.10	JD		4	1,334.06
AURORA ENERGY LLC	3/1/2018	12	7806	30.97	4.49	35.14	28.40	0.12	JD		4	1,129.53
AURORA ENERGY LLC	3/2/2018	19	7808	31.54	4.14	35.52	28.80	0.11	JD		4	1,478.45
AURORA ENERGY LLC	3/3/2018	14	7717	30.25	4.14	35.18	28.52	0.11	JD		4	1,295.50
AURORA ENERGY LLC	3/4/2018	16	7828	31.12	4.14	35.06	28.87	0.11	JD		4	1,420.80
AURORA ENERGY LLC	3/5/2018	13	7701	29.55	5.84	34.82	28.96	0.12	JDRbs	U	4/5	1,224.45
AURORA ENERGY LLC	3/6/2018	13	7730	30.29	5.68	34.66	28.89	0.11	JDRbs	U	4/3	1,231.45
AURORA ENERGY LLC	3/15/2018	12	7823	29.23	5.87	35.65	29.26	0.11	JDRbs	U	4/3	1,131.29
AURORA ENERGY LLC	3/16/2018	13	7821	30.17	4.64	35.76	29.39	0.11	JD		4	1,143.60
AURORA ENERGY LLC	3/17/2018	12	7787	28.41	7.14	35.19	29.27	0.12	BdJDB	J	3/	1,222.59
AURORA ENERGY LLC	3/18/2018	14	7796	27.74	7.52	35.37	29.27	0.12	BdJDB	J	3/	1,287.69
AURORA ENERGY LLC	3/23/2018	14	7716	29.44	5.61	35.32	28.84	0.11	BdJD	J	3/4	1,317.66
AURORA ENERGY LLC	3/22/2018	18	7696	30.24	5.71	34.71	29.36	0.10	BdJD	J	3/4	1,647.66
AURORA ENERGY LLC	3/24/2018	16	7674	32.11	4.93	35.45	27.52	0.10	JD		4	1,412.40
AURORA ENERGY LLC	3/26/2018	12	7716	31.89	4.18	35.11	28.14	0.11	JD		4	1,091.07
AURORA ENERGY LLC	3/30/2018	13	7642	32.31	4.18	35.81	27.75	0.11	JD		4	1,222.82
AURORA ENERGY LLC	3/31/2018	15	7741	31.65	4.24	35.23	28.68	0.11	JD		4	1,385.25
AURORA ENERGY LLC	4/1/2018	12	7733	31.82	4.28	35.96	27.96	0.11	JD		4	1,102.83
AURORA ENERGY LLC	4/5/2018	13	7668	31.60	4.77	35.48	27.94	0.12	JD		4	1,153.39
AURORA ENERGY LLC	4/6/2018	13	7709	31.76	4.68	35.13	28.82	0.12	JD		4	1,205.09
AURORA ENERGY LLC	4/7/2018	12	7802	32.54	4.49	34.85	28.19	0.12	JD		4	1,158.66
AURORA ENERGY LLC	4/8/2018	13	7798	31.23	4.48	35.64	28.28	0.11	JD		4	1,227.09
AURORA ENERGY LLC	4/12/2018	16	7788	31.52	4.69	35.46	28.39	0.12	JD		4	660.30
AURORA ENERGY LLC	4/13/2018	11	7780	31.37	5.02	35.81	28.41	0.12	JD		4	1,060.45
AURORA ENERGY LLC	4/14/2018	8	7733	31.84	4.36	35.32	28.58	0.11	JD		4	884.96
AURORA ENERGY LLC	4/15/2018	8	7768	30.76	4.76	35.74	28.78	0.11	JD		4	899.76
AURORA ENERGY LLC	4/18/2018	12	7810	31.46	4.42	35.66	28.29	0.11	JD		4	1,128.80
AURORA ENERGY LLC	4/19/2018	11	7821	32.18	4.68	34.90	28.08	0.11	JD		4	1,055.06
AURORA ENERGY LLC	4/20/2018	13	7788	32.41	4.90	34.42	28.27	0.10	JD		4	1,274.89

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Analysis Results for 1/1/16 to 6/30/16

AURORA ENERGY LLC	4/21/2016	12	7645	31.76	4.97	34.64	28.61	0.10	JD		4	1,128.72
AURORA ENERGY LLC	4/25/2016	12	7694	30.88	5.60	35.23	29.07	0.11	JD		4	1,120.80
AURORA ENERGY LLC	4/26/2016	10	7794	30.80	4.83	35.24	29.13	0.10	JD		4	1,017.70
AURORA ENERGY LLC	4/27/2016	13	7769	31.50	4.34	35.30	29.64	0.10	JD		4	1,256.45
AURORA ENERGY LLC	4/28/2016	13	7717	31.14	4.83	35.22	29.86	0.11	JD		4	1,284.75
AURORA ENERGY LLC	5/2/2016	12	7733	31.54	4.44	35.22	29.87	0.10	JD		4	1,166.35
AURORA ENERGY LLC	5/3/2016	12	7747	31.52	4.45	35.40	29.96	0.11	JD		4	1,075.35
AURORA ENERGY LLC	5/9/2016	3	7772	30.90	5.16	34.89	29.06	0.13	JD		4	280.15
AURORA ENERGY LLC	5/10/2016	3	7870	32.71	6.13	36.29	29.81	0.12	JD		4	358.58
AURORA ENERGY LLC	5/11/2016	4	7735	33.02	5.17	34.81	28.10	0.08	JD		4	372.65
AURORA ENERGY LLC	5/13/2016	9	7604	33.43	4.51	34.09	27.91	0.10	JD		4	791.40
AURORA ENERGY LLC	5/17/2016	11	7636	32.79	4.33	34.71	28.17	0.10	JD		4	1,084.05
AURORA ENERGY LLC	5/18/2016	11	7485	34.36	4.30	33.96	27.39	0.10	JDJD		34	1,009.25
AURORA ENERGY LLC	5/19/2016	11	7577	32.92	7.83	33.48	26.07	0.13	JDJD		34	1,127.45
AURORA ENERGY LLC	5/20/2016	12	7552	31.46	8.32	34.09	27.32	0.12	JDJD		34	1,178.80
AURORA ENERGY LLC	5/23/2016	14	7661	31.33	6.63	34.90	28.18	0.12	JDJD		34	1,367.20
AURORA ENERGY LLC	5/24/2016	13	7589	31.82	5.34	35.25	27.80	0.12	JDJD		34	1,226.45
AURORA ENERGY LLC	5/25/2016	13	7483	32.89	8.31	34.18	27.03	0.12	JDJD		34	1,237.80
AURORA ENERGY LLC	5/26/2016	10	7627	31.34	8.59	35.37	27.71	0.13	JDJD		34	998.95
AURORA ENERGY LLC	5/31/2016	13	7730	30.85	5.38	36.10	27.71	0.11	JD		4	1,246.35
AURORA ENERGY LLC	6/1/2016	12	7525	30.81	4.68	35.29	28.26	0.10	JDJD		43	1,198.90
AURORA ENERGY LLC	6/2/2016	12	7791	31.52	4.60	35.82	28.26	0.12	JDJD		34	1,078.70
AURORA ENERGY LLC	6/3/2016	14	7647	32.04	8.54	35.38	28.04	0.21	JDBM	K	34	1,568.55
AURORA ENERGY LLC	6/6/2016	13	7411	30.10	8.88	34.34	26.72	0.23	BBJD	K	43	1,274.75
AURORA ENERGY LLC	6/7/2016	11	7464	31.62	8.65	34.18	27.47	0.11	BBJD	K	43	1,035.45
AURORA ENERGY LLC	6/8/2016	11	7491	30.79	7.27	34.34	27.51	0.14	BBJD	K	43	1,040.80
AURORA ENERGY LLC	6/9/2016	10	7513	30.86	6.31	35.15	27.74	0.15	BBJD	K	43	993.00
AURORA ENERGY LLC	6/13/2016	12	7652	31.54	5.53	34.84	28.02	0.12	BBJD		43	1,180.00
AURORA ENERGY LLC	6/14/2016	12	7556	31.46	8.67	34.93	27.78	0.12	JDJD		34	1,177.30
AURORA ENERGY LLC	6/16/2016	24	7514	32.67	8.39	35.18	28.78	0.12	JDJD		34	2,323.89

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Analysis Results for 1/1/16 to 6/30/16

AURORA ENERGY LLC	5/22/2016	16	7808	31.88	6.81	35.05	27.97	0.10	JD/JD	3/4	1,678.60
AURORA ENERGY LLC	6/1/2016	18	7841	31.38	6.61	34.99	27.76	0.13	JD/JD	3/4	1,642.39
AURORA ENERGY LLC	6/23/2016	14	7887	31.92	6.11	34.65	28.36	0.12	JD/JD	3/4	1,428.60
AURORA ENERGY LLC	6/27/2016	12	7880	31.97	6.60	34.63	27.50	0.11	JD/JD	3/4	1,199.08
AURORA ENERGY LLC	6/28/2016	11	7833	31.38	6.94	33.68	27.08	0.12	JD/JD	3/4	1,027.70
AURORA ENERGY LLC	6/29/2016	9	7877	30.89	7.06	35.23	27.03	0.15	JD/JD	3/4	883.15
AURORA ENERGY LLC	6/30/2016	13	7834	31.03	6.60	35.12	27.05	0.13	JD/JD	3/4	1,267.15

Customer Weighted Average

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	113285.30	7883.00	31.21	6.22	35.30	28.29	0.12

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
EIELSON AFB - DFAS	1/5/2016	9	7555	31.88	5.18	34.80	29.07	0.12	Bas/JD	J	4/4	840.80
EIELSON AFB - DFAS	1/6/2016	10	7800	32.32	4.29	34.60	28.64	0.11	JD		4	916.40
EIELSON AFB - DFAS	1/7/2016	10	7724	32.29	3.66	35.34	28.72	0.10	JD		4	908.10
EIELSON AFB - DFAS	1/12/2016	13	7603	32.32	4.49	33.25	28.69	0.12	BAS/JD	J	4/4	927.80
EIELSON AFB - DFAS	1/13/2016	10	7661	32.66	3.68	35.37	28.33	0.09	JD		4	883.65
EIELSON AFB - DFAS	1/14/2016	10	7709	31.71	4.17	35.76	28.37	0.10	JD		4	888.45
EIELSON AFB - DFAS	1/15/2016	10	7776	31.00	4.60	36.59	28.09	0.12	JD		4	909.15
EIELSON AFB - DFAS	1/19/2016	12	7713	31.60	4.38	35.14	28.68	0.10	JD		4	1,071.20
EIELSON AFB - DFAS	1/20/2016	11	7723	32.33	4.18	35.17	28.40	0.12	JD		4	973.20
EIELSON AFB - DFAS	1/21/2016	15	7638	32.53	4.44	34.87	28.17	0.13	JD		4	1,379.50
EIELSON AFB - DFAS	1/22/2016	13	7694	31.93	4.82	35.18	28.50	0.11	JD		4	1,155.90
EIELSON AFB - DFAS	1/26/2016	13	7490	32.32	6.49	34.27	28.01	0.11	JD		4	1,134.75
EIELSON AFB - DFAS	1/27/2016	13	7553	31.49	6.77	34.90	27.88	0.12	BAS/JD	J	4/4	1,215.85
EIELSON AFB - DFAS	1/28/2016	15	7573	32.67	4.75	34.63	27.96	0.10	BAS/JD	J	4/4	1,390.75
EIELSON AFB - DFAS	2/2/2016	12	7567	32.09	4.35	35.17	27.90	0.10	JD/BAS	U	4/3	1,112.15
EIELSON AFB - DFAS	2/3/2016	12	7717	31.10	5.07	34.69	28.93	0.14	BAS/JD	J	3/4	1,134.85
EIELSON AFB - DFAS	2/4/2016	15	7634	30.86	5.27	34.68	28.51	0.17	BAS/JD	J	4/4	1,191.15
EIELSON AFB - DFAS	2/5/2016	12	7638	31.11	5.53	35.41	27.68	0.13	JD/BAS	U	4/4	1,132.75

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/16 to 6/30/16

Customer Weighted Average

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
UNIVERSITY OF ALASKA	31602.70	7967.00	31.27	5.37	35.30	28.06	0.12

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	119382.35	7980.00	37.31	5.22	35.50	26.26	0.13
EIELSON AFB - DFAS	80214.66	7811.00	31.53	6.47	34.90	26.02	0.12
FORT WAINWRIGHT ACCounting	126589.60	7820.00	31.46	5.41	35.01	26.08	0.12
OTHER COAL SALES	70008.05	7809.00	29.94	6.15	35.62	28.28	0.13
UNIVERSITY OF ALASKA	31602.70	7967.00	31.27	5.37	35.30	28.06	0.12
Total:	423697.4	7861.59	31.16	5.48	35.18	26.17	0.12

This analysis is representative of the coal shipped. The sulfur content in this shipment was analyzed using sulfur standard ASTM D4239.

Coleen Thompson **Date** 7-18-16

Coleen Thompson

Signature

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/16 to 12/31/16

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	7/6/2016	18	7570	30.60	6.78	34.69	27.91	0.13	JD/JD		3/4	1,417.10
AURORA ENERGY LLC	7/8/2016	10	7691	30.50	6.07	35.20	28.23	0.11	JD/JD		3/4	999.55
AURORA ENERGY LLC	7/8/2016	15	7569	31.27	6.06	33.94	27.15	0.11	JD/JD		3/4	1,369.70
AURORA ENERGY LLC	7/11/2016	18	7499	32.08	6.04	34.40	27.48	0.11	JD/JD		3/4	1,782.30
AURORA ENERGY LLC	7/12/2016	14	7507	30.38	7.67	35.14	28.80	0.18	B&/JD	R	4/3	1,387.18
AURORA ENERGY LLC	7/14/2016	18	7561	29.88	7.43	36.07	27.62	0.18	B&/JD	RJ	4/3	1,766.60
AURORA ENERGY LLC	7/18/2016	17	7711	29.16	7.11	35.63	27.99	0.17	JD/B&	R	3/4	1,594.70
AURORA ENERGY LLC	7/19/2016	15	7693	29.26	8.72	35.48	28.66	0.17	B&/JD	R	4/3	1,378.10
AURORA ENERGY LLC	7/21/2016	18	7652	29.41	8.68	35.14	28.47	0.17	B&/JD	R	4/3	1,724.10
AURORA ENERGY LLC	7/25/2016	12	7588	29.04	7.41	34.63	28.73	0.17	B&/JD	R	4/3	1,116.88
AURORA ENERGY LLC	7/26/2016	17	7590	29.91	7.20	34.67	27.92	0.16	B&/JD	R	4/3	1,595.30
AURORA ENERGY LLC	7/28/2016	11	7616	29.39	7.50	35.16	27.97	0.16	B&/JD	R	4/3	1,042.70
AURORA ENERGY LLC	8/1/2016	14	7598	29.24	8.09	34.84	27.87	0.15	B&/JD	R	4/3	1,351.66
AURORA ENERGY LLC	8/2/2016	14	7498	30.31	8.00	34.62	27.09	0.15	B&/JD	R	4/3	1,377.26
AURORA ENERGY LLC	8/4/2016	13	7543	30.45	7.11	34.97	27.47	0.14	B&/JD	R	4/3	1,234.55
AURORA ENERGY LLC	8/8/2016	19	7554	29.57	8.13	34.84	27.67	0.15	B&/JD	R	4/3	1,838.26
AURORA ENERGY LLC	8/9/2016	17	7555	29.32	8.20	34.99	27.55	0.16	B&/JD	R	4/3	1,737.15
AURORA ENERGY LLC	8/12/2016	17	7518	28.78	8.63	35.37	28.93	0.22	JD/B&	R	3/4	1,641.20
AURORA ENERGY LLC	8/15/2016	17	7582	30.43	8.18	35.09	28.30	0.21	B&/JD	R	4/3	1,641.00
AURORA ENERGY LLC	8/19/2016	17	7583	29.02	7.88	35.79	27.31	0.18	B&/JD	R	4/3	1,617.55
AURORA ENERGY LLC	8/19/2016	16	7544	29.54	7.65	35.74	28.82	0.17	B&/JD	R	4/3	1,519.30
AURORA ENERGY LLC	8/23/2016	18	7481	29.32	8.70	36.15	28.83	0.16	B&/JD	R	4/3	1,660.65
AURORA ENERGY LLC	8/24/2016	18	7533	29.26	7.19	36.87	28.96	0.16	B&/JD	R	4/3	1,808.55
AURORA ENERGY LLC	8/26/2016	18	7590	31.48	6.63	35.04	27.81	0.13	JD/JD		4/3	1,682.30
AURORA ENERGY LLC	8/29/2016	16	7289	30.74	8.14	34.44	26.70	0.22	JD/JD		4/3	1,639.20
AURORA ENERGY LLC	8/30/2016	19	7562	30.55	6.81	35.48	27.08	0.16	JD/JD		3/4	1,897.80
AURORA ENERGY LLC	9/2/2016	28	7500	30.40	7.86	35.22	26.74	0.16	JD/JD		3/4	2,510.75
AURORA ENERGY LLC	9/6/2016	18	7450	32.43	6.09	34.86	26.83	0.12	JD/JD		4/3	1,694.70
AURORA ENERGY LLC	9/7/2016	17	7524	31.76	5.90	35.85	26.70	0.12	JD/B&	R	3/4	1,600.90
AURORA ENERGY LLC	9/8/2016	10	7550	30.91	6.84	34.82	27.55	0.13	JD/B&	R	4/4	883.55

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AURORA ENERGY LLC	9/6/2016	10	7575	30.37	6.69	35.37	27.68	0.13	BituD	K	4/3	869.50
AURORA ENERGY LLC	9/27/2016	7	7656	29.53	7.77	36.09	26.62	0.14	JDUD		3/4	660.95
AURORA ENERGY LLC	9/30/2016	18	7663	29.00	7.19	36.59	27.26	0.13	JDBit	K	3/4	1,783.00
AURORA ENERGY LLC	10/5/2016	34	7681	30.56	7.00	35.56	26.56	0.11	JDBit	K	3/4	2,244.55
AURORA ENERGY LLC	10/9/2016	28	7514	30.13	7.52	34.76	27.56	0.12	BitUD	K	4/3	2,682.10
AURORA ENERGY LLC	10/15/2016	20	7619	29.99	6.97	36.09	27.97	0.13	BitUD	K	4/3	1,898.45
AURORA ENERGY LLC	10/11/2016	21	7415	29.56	8.37	34.68	28.60	0.12	JD		4	1,974.29
AURORA ENERGY LLC	10/17/2016	14	7725	30.81	6.80	35.47	28.22	0.11	JD		4	1,327.55
AURORA ENERGY LLC	10/18/2016	15	7566	30.66	6.74	36.76	27.65	0.11	JDUD		3/4	910.99
AURORA ENERGY LLC	10/19/2016	11	7674	30.81	6.78	35.44	28.17	0.10	JDUD		3/4	840.90
AURORA ENERGY LLC	10/24/2016	12	7750	29.11	6.56	36.37	27.97	0.13	JDUD		3/4	1,137.48
AURORA ENERGY LLC	10/25/2016	12	7729	29.22	6.61	36.28	27.99	0.12	Bit		4	1,083.15
AURORA ENERGY LLC	10/26/2016	14	7708	28.38	7.47	36.44	27.71	0.12	BitUD		3/4	1,171.40
AURORA ENERGY LLC	10/27/2016	14	7765	27.43	7.69	37.53	27.35	0.13	BituUD		3/4	1,245.83
AURORA ENERGY LLC	10/31/2016	14	7742	26.38	8.02	37.78	28.04	0.14	Bit		4	1,220.95
AURORA ENERGY LLC	11/1/2016	18	7705	26.56	8.09	38.27	28.09	0.14	Bit		4	1,200.10
AURORA ENERGY LLC	11/2/2016	14	7726	26.53	8.80	37.76	28.91	0.14	Bit		4	1,208.95
AURORA ENERGY LLC	11/3/2016	13	7774	26.33	8.55	37.90	27.22	0.14	Bit		4	1,100.70
AURORA ENERGY LLC	11/7/2016	16	7650	27.17	8.93	37.45	26.47	0.13	Bit		4	1,346.80
AURORA ENERGY LLC	11/8/2016	15	7646	26.81	8.38	37.93	26.86	0.14	Bit		4	1,316.55
AURORA ENERGY LLC	11/9/2016	15	7631	27.00	8.17	37.46	26.37	0.14	Bit		4	1,318.60
AURORA ENERGY LLC	11/10/2016	16	7714	26.75	8.56	37.61	27.09	0.13	Bit		4	1,394.80
AURORA ENERGY LLC	11/14/2016	16	7658	26.44	8.11	37.77	28.68	0.14	Bit		4	1,432.15
AURORA ENERGY LLC	11/16/2016	16	7680	27.17	8.43	37.64	26.60	0.14	Bit		4	1,406.00
AURORA ENERGY LLC	11/17/2016	16	7708	27.38	7.88	37.64	27.34	0.13	Bit		4	1,335.60
AURORA ENERGY LLC	11/21/2016	16	7710	27.01	8.43	37.84	26.73	0.13	Bit		4	1,466.16
AURORA ENERGY LLC	11/22/2016	18	7751	27.30	8.01	38.38	26.34	0.13	Bit		4	1,754.99
AURORA ENERGY LLC	11/23/2016	17	7736	27.32	7.97	38.15	26.81	0.13	Bit		4	1,402.79
AURORA ENERGY LLC	11/28/2016	10	7705	27.45	7.89	37.39	27.29	0.13	Bit		4	876.20
AURORA ENERGY LLC	11/29/2016	10	7494	27.88	9.89	36.20	26.04	0.13	Bit		4	823.55
AURORA ENERGY LLC	11/30/2016	10	7596	29.85	6.92	36.51	26.76	0.13	JD		4	881.80
AURORA ENERGY LLC	12/1/2016	11	6699	28.08	14.52	33.81	24.55	0.12	BitUD		3/4	913.05

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Analysis Results for 7/1/16 to 12/31/16

AURORA ENERGY LLC	12/5/2016	12	7660	30.15	6.84	35.31	28.21	0.13	JD	4	1,048.08
AURORA ENERGY LLC	12/6/2016	12	7635	29.90	6.82	35.74	27.54	0.14	JD	4	1,034.60
AURORA ENERGY LLC	12/7/2016	11	7681	30.39	6.66	35.64	28.32	0.12	BelJD	5/4	934.95
AURORA ENERGY LLC	12/8/2016	12	7684	28.22	7.21	37.06	26.52	0.12	JD	4	1,028.60
AURORA ENERGY LLC	12/12/2016	15	7734	28.36	7.03	38.64	26.08	0.18	JD	4	1,336.05
AURORA ENERGY LLC	12/13/2016	15	7696	27.80	8.18	37.22	26.77	0.14	JD	4	1,297.80
AURORA ENERGY LLC	12/14/2016	16	7685	27.72	7.69	38.60	27.40	0.14	JD	4	1,347.60
AURORA ENERGY LLC	12/15/2016	8	7679	27.55	7.85	38.64	27.05	0.13	JD/Bel	4/5	795.60
AURORA ENERGY LLC	12/19/2016	18	7696	27.91	8.63	37.07	26.40	0.14	Bel/JD	5/4	1,625.50
AURORA ENERGY LLC	12/20/2016	23	7629	28.75	8.36	36.18	26.74	0.13	Bel	5	2,003.15
AURORA ENERGY LLC	12/21/2016	8	7177	33.26	5.98	34.15	28.60	0.11	JD	4	702.25
AURORA ENERGY LLC	12/22/2016	7	7498	30.41	8.82	35.74	26.93	0.13	JD	4	625.80
AURORA ENERGY LLC	12/27/2016	12	7617	30.43	8.60	35.98	27.01	0.13	JD	4	1,202.80
AURORA ENERGY LLC	12/28/2016	15	7774	30.23	5.78	36.85	27.49	0.13	JD/Bel	4/5	1,132.75
AURORA ENERGY LLC	12/29/2016	14	7656	30.08	8.37	36.50	27.06	0.13	Bel/JD	5/4	1,242.85
AURORA ENERGY LLC	12/29/2016	4	7427	30.41	7.75	35.38	26.43	0.13	Bel/JD	5/4	355.00
AURORA ENERGY LLC	12/31/2016	14	7666	27.72	8.27	37.23	26.78	0.14	Bel/JD	5/4	1,292.45

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	107687.38	7604.00	29.23	7.61	36.99	27.17	0.14

This analysis is representative of the coal shipped. The sulfur content in this shipment was analyzed using sulfur standard ASTM D4239.

Coleen Thompson Date 1-11-17

Coleen Thompson

Signature

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/17 to 6/30/17

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	1/3/2017	18	7477	30.01	7.72	36.14	26.13	0.14	JD		4	1,892.16
AURORA ENERGY LLC	1/4/2017	19	7629	29.79	6.81	35.98	27.62	0.14	JD		4	1,625.15
AURORA ENERGY LLC	1/5/2017	18	7548	30.25	7.60	36.83	27.32	0.16	JD/STK		4/L	1,722.00
AURORA ENERGY LLC	1/6/2017	19	7696	32.13	5.19	35.58	27.11	0.13	JD		4	1,987.00
AURORA ENERGY LLC	1/10/2017	16	7711	31.53	4.83	35.88	27.66	0.11	JD		4	1,414.60
AURORA ENERGY LLC	1/11/2017	11	7587	32.46	4.80	35.38	27.37	0.12	JD		4	960.63
AURORA ENERGY LLC	1/12/2017	15	7657	32.36	5.01	35.04	27.63	0.12	JD		4	1,360.55
AURORA ENERGY LLC	1/13/2017	10	7667	31.58	5.05	35.99	27.38	0.13	JD		4	911.65
AURORA ENERGY LLC	1/16/2017	11	7464	33.02	5.29	34.59	27.11	0.13	JD		4	953.00
AURORA ENERGY LLC	1/17/2017	7	7796	31.19	4.49	35.71	28.65	0.11	JD		4	600.55
AURORA ENERGY LLC	1/18/2017	8	7453	32.23	5.64	35.11	27.09	0.13	JD		4	822.05
AURORA ENERGY LLC	1/20/2017	7	7617	33.70	4.45	34.77	27.08	0.11	JD		4	636.35
AURORA ENERGY LLC	1/21/2017	14	7569	33.03	4.39	34.94	27.75	0.10	JD		4	1,222.40
AURORA ENERGY LLC	1/23/2017	11	7669	32.37	4.39	35.00	28.29	0.10	JD		4	970.49
AURORA ENERGY LLC	1/24/2017	11	7726	32.24	4.34	35.68	27.75	0.10	JD		4	941.95
AURORA ENERGY LLC	1/25/2017	11	7644	32.08	4.71	35.29	27.94	0.09	JD		4	979.55
AURORA ENERGY LLC	1/26/2017	8	7672	32.05	5.48	34.92	27.57	0.10	JD		4	718.16
AURORA ENERGY LLC	1/27/2017	11	7639	31.03	5.90	36.16	26.84	0.12	JD		4	881.40
AURORA ENERGY LLC	1/30/2017	11	7672	32.29	5.53	35.74	26.45	0.13	JD		4	853.19
AURORA ENERGY LLC	1/31/2017	11	7217	32.68	6.09	34.88	25.31	0.14	JD		4	975.95
AURORA ENERGY LLC	2/1/2017	24	8822	34.48	5.09	32.84	24.60	0.14	JD		4	2,208.19
AURORA ENERGY LLC	2/1/2017	4	7170	33.55	6.67	33.52	26.17	0.13	JD		4	353.30
AURORA ENERGY LLC	2/2/2017	3	7353	33.71	5.59	33.73	26.96	0.13	JD		4	267.26
AURORA ENERGY LLC	2/6/2017	9	7661	32.65	4.86	34.74	27.55	0.12	JD		4	790.05
AURORA ENERGY LLC	2/7/2017	10	7554	33.29	4.68	34.52	27.13	0.11	JD		4	877.60
AURORA ENERGY LLC	2/8/2017	10	7681	32.18	4.48	35.19	28.22	0.11	JD		4	869.65
AURORA ENERGY LLC	2/9/2017	9	7661	32.24	4.61	35.19	28.01	0.12	JD		4	788.00
AURORA ENERGY LLC	2/10/2017	10	7726	31.65	4.62	35.78	28.00	0.11	JD		4	875.35
AURORA ENERGY LLC	2/13/2017	9	7625	33.37	4.69	35.17	27.77	0.13	JD		4	795.10
AURORA ENERGY LLC	2/14/2017	8	7567	33.36	4.97	35.16	27.33	0.11	JD		4	662.60

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/17 to 6/30/17

AURORA ENERGY LLC	2/15/2017	10	7834	32.54	4.49	35.36	27.61	0.11	JD	4	869.00
AURORA ENERGY LLC	2/16/2017	6	7468	33.04	4.58	35.17	26.62	0.12	JD	4	717.70
AURORA ENERGY LLC	2/17/2017	9	7463	33.10	5.10	34.31	27.52	0.12	JD	4	814.60
AURORA ENERGY LLC	2/21/2017	8	7568	32.49	4.85	35.16	27.48	0.12	JD	4	751.78
AURORA ENERGY LLC	2/22/2017	11	7557	33.17	4.44	34.73	27.66	0.11	JD	4	960.00
AURORA ENERGY LLC	2/23/2017	12	7563	32.96	4.14	35.22	27.69	0.10	JD	4	1,046.50
AURORA ENERGY LLC	2/24/2017	10	7668	32.36	4.23	35.42	27.66	0.11	JD	4	997.20
AURORA ENERGY LLC	2/27/2017	14	7690	32.22	4.51	35.08	27.28	0.11	JD	4	1,178.30
AURORA ENERGY LLC	3/1/2017	13	7165	33.76	5.52	34.38	26.32	0.11	JD	4	1,197.25
AURORA ENERGY LLC	3/2/2017	12	7074	33.61	5.95	34.70	25.75	0.11	JD	4	1,089.10
AURORA ENERGY LLC	3/3/2017	17	7491	31.92	5.88	35.09	27.21	0.11	JD	4	1,454.95
AURORA ENERGY LLC	3/6/2017	26	7219	32.39	6.19	35.29	26.16	0.11	JD	4	2,369.10
AURORA ENERGY LLC	3/8/2017	13	7505	31.11	6.36	35.34	27.20	0.12	JD/BD	4/8	1,072.30
AURORA ENERGY LLC	3/11/2017	28	7281	33.37	5.38	35.01	26.24	0.12	JD/BD	4/8	2,583.40
AURORA ENERGY LLC	3/11/2017	12	7569	32.00	4.79	36.19	27.04	0.10	JD/Bid	4/8	1,078.05
AURORA ENERGY LLC	3/14/2017	13	7551	31.55	4.89	35.87	27.69	0.11	JD	4	1,119.29
AURORA ENERGY LLC	3/15/2017	16	7585	31.98	5.01	35.77	27.33	0.12	JD	4	1,331.40
AURORA ENERGY LLC	3/20/2017	13	7534	32.29	4.63	35.84	27.54	0.12	JD	4	1,120.40
AURORA ENERGY LLC	3/21/2017	12	7579	32.14	4.68	35.78	27.42	0.12	JD	4	1,030.80
AURORA ENERGY LLC	3/22/2017	12	7567	32.19	4.11	35.51	28.20	0.11	JD	4	1,046.16
AURORA ENERGY LLC	3/23/2017	14	7599	31.37	5.68	34.77	27.97	0.12	JD/GRP	4/C	1,249.30
AURORA ENERGY LLC	3/31/2017	14	7551	31.46	5.35	35.38	27.81	0.13	JD/GRP	4/C	1,246.80
AURORA ENERGY LLC	3/28/2017	14	7626	31.21	5.57	34.76	28.47	0.13	JD/GRP	4/M	1,254.00
AURORA ENERGY LLC	3/29/2017	10	7571	31.75	5.59	34.89	27.81	0.13	JD/GRP	4/M	902.00
AURORA ENERGY LLC	3/30/2017	13	7577	31.50	5.45	35.48	27.69	0.12	JD/GRP	4/M	1,119.90
AURORA ENERGY LLC	4/3/2017	13	7648	31.96	4.45	36.24	27.36	0.11	JD	4	1,133.18
AURORA ENERGY LLC	4/4/2017	13	7653	32.13	4.28	36.07	27.52	0.10	JD	4	1,148.06
AURORA ENERGY LLC	4/5/2017	13	7681	31.32	5.21	35.50	27.97	0.13	JD/GRP	4/C	1,164.90
AURORA ENERGY LLC	4/6/2017	8	7616	32.09	4.35	36.26	27.12	0.10	JD	4	726.88
AURORA ENERGY LLC	4/10/2017	11	7682	32.21	4.28	37.03	26.49	0.11	JD	4	977.46
AURORA ENERGY LLC	4/11/2017	12	7681	31.95	4.39	36.97	27.69	0.10	JD	4	1,066.68
AURORA ENERGY LLC	4/13/2017	7	7682	33.61	6.28	35.11	27.82	0.11	JD	4	674.75

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/17 to 6/30/17

AURORA ENERGY LLC	4/13/2017	11	7360	34.02	4.57	34.56	26.86	0.10	JD	4	1,018.96
AURORA ENERGY LLC	4/18/2017	16	7644	32.05	4.38	35.70	26.91	0.11	JD	4	1,281.00
AURORA ENERGY LLC	4/19/2017	7	7853	31.22	5.38	35.74	27.64	0.13	JD	4	624.96
AURORA ENERGY LLC	4/20/2017	16	7624	32.50	4.35	35.84	27.31	0.11	JD	4	1,014.50
AURORA ENERGY LLC	4/21/2017	17	7590	31.69	4.70	33.91	27.50	0.11	JD	4	1,091.00
AURORA ENERGY LLC	4/24/2017	16	7675	31.63	4.46	36.48	27.44	0.10	JD	4	1,091.00
AURORA ENERGY LLC	4/25/2017	13	7577	33.14	4.00	35.39	27.44	0.11	JD	4	1,272.66
AURORA ENERGY LLC	4/26/2017	9	7592	33.84	3.51	35.09	27.62	0.10	JD	4	864.20
AURORA ENERGY LLC	4/27/2017	8	7621	32.87	3.81	35.16	27.16	0.10	JD	4	779.48
AURORA ENERGY LLC	5/1/2017	7	7734	31.83	4.44	36.23	27.71	0.12	JD	4	845.76
AURORA ENERGY LLC	5/2/2017	6	7739	30.69	4.80	36.41	28.10	0.11	JD	4	553.10
AURORA ENERGY LLC	5/3/2017	4	7629	30.99	4.22	36.19	28.62	0.11	JD	4	371.56
AURORA ENERGY LLC	5/8/2017	4	7481	33.20	4.78	35.09	26.88	0.12	JD	4	381.76
AURORA ENERGY LLC	5/9/2017	8	7489	32.64	5.38	34.89	27.42	0.11	JD	4	517.56
AURORA ENERGY LLC	5/11/2017	4	7536	31.86	5.27	35.88	27.02	0.11	JD	4	368.76
AURORA ENERGY LLC	5/15/2017	9	7599	31.86	4.95	36.29	28.91	0.10	JD	4	807.40
AURORA ENERGY LLC	5/16/2017	8	7653	31.97	4.69	36.40	28.08	0.10	JD	4	799.40
AURORA ENERGY LLC	5/17/2017	6	7574	33.83	4.09	34.88	27.20	0.09	JD	4	466.56
AURORA ENERGY LLC	5/18/2017	4	7560	33.31	3.42	35.81	27.47	0.09	JD	4	364.88
AURORA ENERGY LLC	5/19/2017	7	7656	32.09	4.24	35.58	27.70	0.10	JD	4	693.30
AURORA ENERGY LLC	5/22/2017	16	7756	31.40	4.24	36.48	27.87	0.10	JD	4	1,430.40
AURORA ENERGY LLC	5/23/2017	12	7512	33.97	4.17	35.79	26.91	0.13	JD	4	1,080.40
AURORA ENERGY LLC	5/24/2017	12	7666	32.70	3.95	35.99	27.36	0.12	JD	4	1,097.30
AURORA ENERGY LLC	5/26/2017	14	7667	31.91	4.59	36.49	27.02	0.11	JD	4	1,311.30
AURORA ENERGY LLC	5/30/2017	9	7675	31.80	4.72	36.29	27.19	0.11	JD	4	839.58
AURORA ENERGY LLC	5/31/2017	8	7693	31.83	4.71	36.50	28.53	0.11	JD	4	747.68
AURORA ENERGY LLC	6/1/2017	3	7701	31.47	4.41	37.06	27.97	0.10	JD	4	365.40
AURORA ENERGY LLC	6/2/2017	4	7777	31.10	4.13	36.64	28.13	0.10	JD	4	346.30
AURORA ENERGY LLC	6/5/2017	12	7660	32.12	4.55	35.36	27.56	0.10	JD	4	1,061.76
AURORA ENERGY LLC	6/6/2017	13	7684	32.53	4.47	35.40	27.81	0.11	JD	4	1,185.40
AURORA ENERGY LLC	6/8/2017	12	7636	32.08	4.46	35.99	27.53	0.10	JD	4	1,067.80
AURORA ENERGY LLC	6/9/2017	11	7674	31.80	4.30	36.31	27.70	0.11	JD	4	1,011.28

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/17 to 6/30/17

AURORA ENERGY LLC	6/12/2017	12	7609	32.30	4.33	36.00	27.38	0.10	JD	4	1,063.65
AURORA ENERGY LLC	6/13/2017	12	7682	31.87	4.25	36.36	27.54	0.09	JD	4	1,140.00
AURORA ENERGY LLC	6/15/2017	12	7678	31.97	4.76	36.23	27.06	0.12	JD	4	1,093.90
AURORA ENERGY LLC	6/16/2017	13	7665	32.28	4.53	35.98	27.21	0.10	JD	4	1,167.30
AURORA ENERGY LLC	6/19/2017	11	7699	32.34	5.01	36.49	27.31	0.10	JD	4	882.95
AURORA ENERGY LLC	6/20/2017	13	7714	32.35	4.07	36.98	27.60	0.10	JD	4	1,115.05
AURORA ENERGY LLC	6/22/2017	12	7665	33.22	4.39	35.52	26.77	0.10	JD	4	1,063.45
AURORA ENERGY LLC	6/23/2017	13	7642	32.79	4.57	35.68	27.17	0.10	JD	4	1,153.90
AURORA ENERGY LLC	6/26/2017	8	7699	32.23	4.70	35.95	27.52	0.12	JD	4	701.60
AURORA ENERGY LLC	6/27/2017	8	7754	31.81	4.08	36.33	27.76	0.11	JD	4	701.85
AURORA ENERGY LLC	6/28/2017	8	7711	31.93	4.58	36.91	26.61	0.11	JD	4	752.00
AURORA ENERGY LLC	6/29/2017	8	7760	31.78	4.09	36.29	27.65	0.10	JD	4	666.20

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	106040.35	7567.00	32.20	4.68	35.55	27.28	0.11

This analysis is representative of the coal shipped. The sulfur content in this shipment was analyzed using sulfur standard ASTM D4239.

Colleen Thompson Date 7-5-17

Colleen Thompson

Signature

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Usibelli Coal Mine

Usibelli Coal Mine

Usibelli Coal Mine

This analysis represents conditions of the coal shipped
The sulfur content in the shipment was analyzed
using [illegible]

Ben Zegmur Date: [illegible]

[illegible]
Signature

Fairbanks North Star Borough

Evaluation of Electrostatic Precipitators (ESP) as Retrofit Control Devices

FORMATION MECHANISMS AND PHYSICAL PROPERTIES OF PARTICLES FROM WOOD COMBUSTION FOR DESIGN AND OPERATION OF ELECTROSTATIC PRECIPITATORS

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ABSTRACT: The particles from biomass combustion are collected in a laboratory electrostatic precipitator (ESP). Three different combustion regimes are maintained by a modified pellet boiler, i.e., high temperature and sufficient oxygen, high temperature and local lack of oxygen, and low temperature. The resulting particles are classified as salts, soot, and condensable organic compounds (COC) based on the particle type expected from the theory of particle formation. The chemical and electrical properties are analysed and confirm the classification: While salts exhibit a low carbon content, soot and COC are high in carbon. Soot and COC can be distinguished by significantly different molar C/H-ratio being 6.44 for soot and 1.24 for COC. The electrical conductivity, which is a key parameter for the precipitation and dust layer built-up in the ESP, is measured at different temperatures and humidities. Significant differences in conductivity are found for salts, soot, and COC, and in addition, a strong influence of the humidity of the flue gas is observed. Salt is confirmed to be ideal for ESP, while soot reveals high conductivity leading to re-entrainment of agglomerated particles, and COC exhibit low conductivity leading to back-corona which can be limiting at low humidity. The presented particle properties can be applied as guideline for ESP design and operation.
Keywords: Aerosol, particle emission, chemical composition, combustion, gas cleaning.

1 INTRODUCTION

1.1 Background

Particulate Matter smaller 10 micron (PM_{10}) is related to adverse health effects. Due to more stringent emission limit values for small and medium scale applications, there is an increasing demand for particle precipitation for biomas combustion plants. Beside applications for industrial plants > 1 MW, where particle precipitation is widely applied nowadays, there is an additional need for small and medium scale applications, i.e.,

a) in residential heating from 5 kW – 70 kW and
b) in automatic boilers from 200 kW – 1 MW.

For both categories, electrostatic precipitators (ESP) have been introduced to the market in the past few years in countries which implemented stringent emission limit values for these categories such as e.g. Switzerland.

The principles for ESP – as shown in Figure 1 – are well known and design parameters are available in the literature for different flue gas composition and particle characteristics [1–3]. However, experiences for ESP so far result mainly from large scale applications as e.g. thermal power stations with constant operation at high flue gas temperatures. In addition, particle characteristics are mainly based on coal, while data from wood particles are scarce [4]. Consequently, the following specific needs have to be considered for applications of ESP in wood combustion devices:

1. Particles from small scale wood combustion consist of different components, which can be basically divided into three fractions, i.e.,
   a) inorganic particulates (salts),
   b) soot (available as solid particles in the flue gas),
   c) condensable organic compounds (COC).
2. The concentration of H_2O as well as of CO, CO_2 and O_2 can vary in a wide range and consequently the precipitation conditions in the ESP (which are strongly influenced e.g. by the content of H_2O).
3. Wood combustion is often applied for heating purposes where on-/off-operation and short periods of uninterrupted operation are common [5]. This results in low flue gas temperatures thus potentially enabling condensation of water vapour and – if present in the flue gas – organic condensates in the ESP. To avoid condensation, ESP are usually shut-off at low flue gas temperatures, which can result in a poor availability and consequently increased emissions in real-life operation. In addition, transient conditions during start-up and shut-down, which are not considered in type tests or during on-site acceptance inspection, can play an important role to the operation of the ESP and the clean gas emissions.

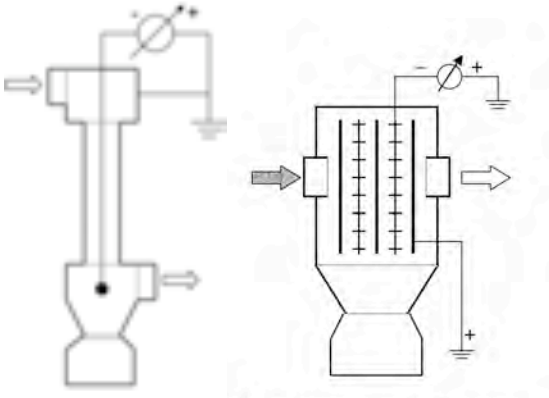


Figure 1: Principles of electrostatic precipitator (ESP).

1.2 Aim

The aim of the present investigation is to collect precipitation properties of particles and flue gases from wood combustion under different operation conditions. These data shall be used as a basis for future design and operation parameters for ESP for wood combustion applications. Furthermore, based on these results, ope-

rating problems such as back-ionisation and re-entrainment shall be related to dedicated combustion conditions thus enabling improved operation of the combustion system and the ESP. Back-ionisation is usually referred to as back corona and describes the localized discharge which occurs at the collecting electrode surface, when that surface becomes coated with an electrically insulating layer of poorly conducting particles such as e.g. COC and thus reduce the precipitation performance. Re-entrainment may occur for agglomerates with low electrical resistivity such as soot.

2 THEORY

Biomass combustion is related to three basic types of particles, which are summarized as 'salts', 'soot', and Condensable Organic Compounds 'COC', and exhibit completely different chemical and physical properties:

- Inorganic particles, basically salts, are formed from minerals (i.e., ash constituents) in the fuel. These particles are dominant at near-complete combustion
- COC are formed in different processes:
  – At low temperature volatile or condensed organic compounds are formed from wood pyrolysis with characteristic compounds depending on residence time, heating rate, temperature and other operation parameters.
  – At moderate temperatures and local lack of oxygen, organic compounds can be converted to secondary tars, which appear as condensables.
- Soot is formed from organic precursors in zones of high temperatures and lack of oxygen, where volatiles and primary tars react to secondary tars and form polyaromatic hydrocarbons, which consequently can form soot particles by further agglomaration and release of hydrogen.

The formation mechanisms are described in Figure 2. In automatic wood combustion, nearly complete combustion can be achieved and hence salts are dominant as particles. However, during start-up, and in phases of inappropriate operation, condensables or soot can also be emitted from automatic plants.

Incomplete combustion is often found in manual wood combustion, whereby soot or condensables can be the dominant part of the total particulate matter released to the atmosphere. Due to the different temperature regimes and the different influence of the residence time for soot and COC formation, usually either one of the two particle type dominates the particle ensemble.

Table 1 summarizes the main properties of salt, soot, and COC found in biomass flue gases.

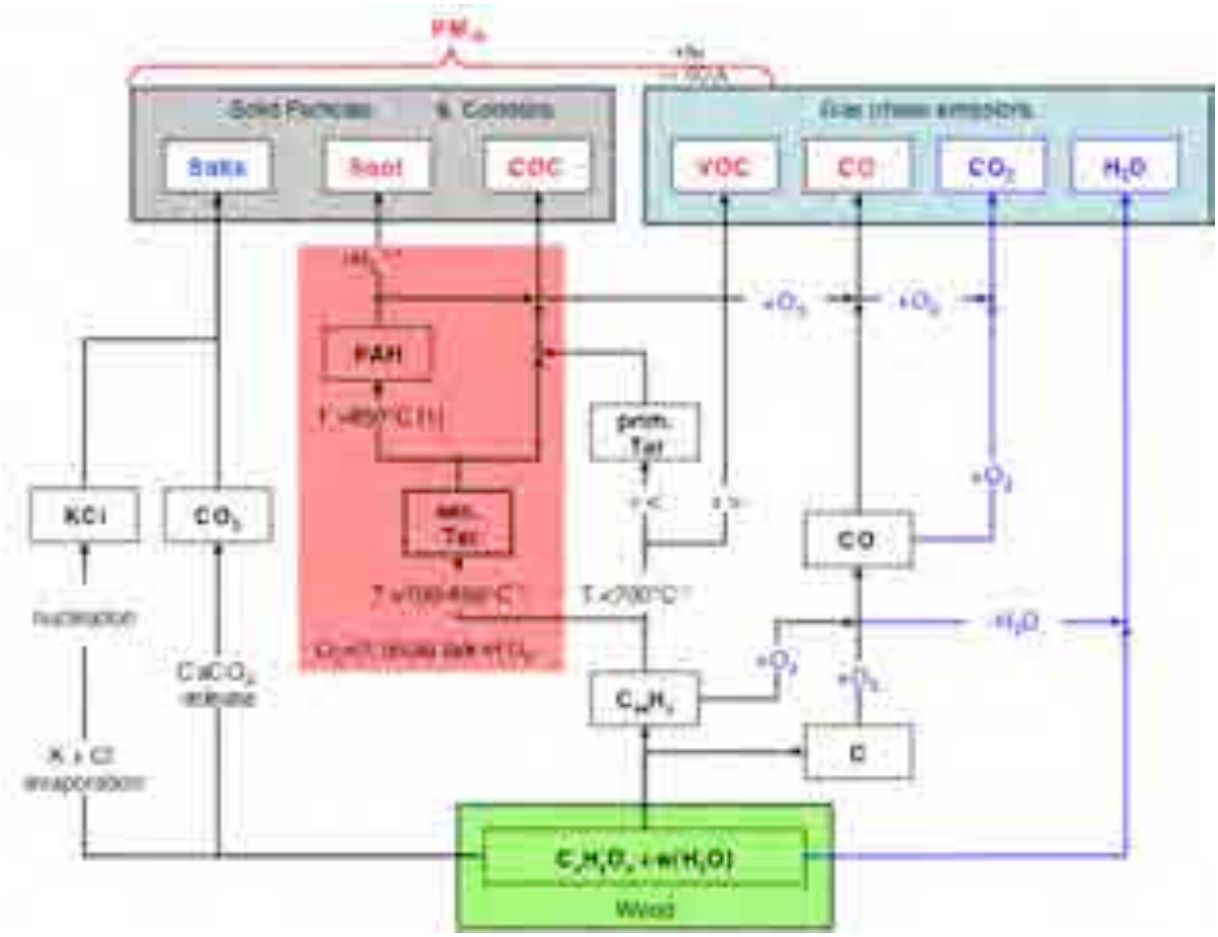


Figure 2: Mechanisms of aerosol formation in biomass combustion. *[6], **[7].

3 METHOD

For the experiments, an electrostatic lab-scale precipitator was designed as tube type ESP with a maximum voltage of U_{max} = –65 kV and connected to a pellet boiler (Figure 3). The pellet boiler was modified to enable stationary operation at specific combustion conditions, which normally exist only during transient phases such as during start-up. The ESP was designed to enable precipitation efficiencies as typically found in commercial small and medium scale ESP, i.e., safely > 90% for all particle sizes and > 95% as average precipitation efficiency for typical particle collectives found in biomass combustion (Figure 4). Electrical conductivity was analysed acc. to IEEE Std 548-1984 (due to missing valid standards, the old standard is used). The relevance of the conductivity measurements for ESP is described in [10]).

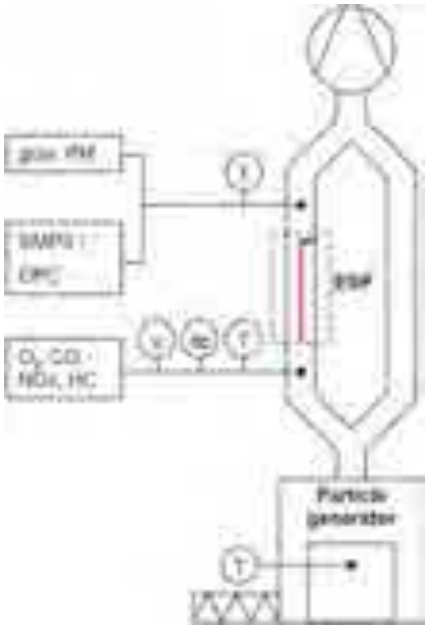


Figure 3: Experimental setup.

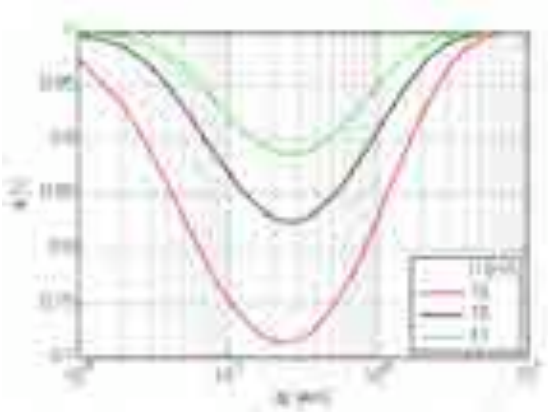


Figure 4: Calculated precipitation efficiency of the laboratory ESP as function of the particle size and the voltage. Design parameters of the ESP: L 1000 mm, D 100 mm, u 1 m/s, SCA 45 s/m, U_{max} –65kV.

4 RESULTS

4.1 Particle types

In biomass combustion, three combustion regimes can be distinguished which – among other parameters – are related to the level of excess air available in the combustion chamber [11]. Figure 5 shows the particles found in the present laboratory device for different excess air ratios:

At low excess air ratio (regime C), soot is formed in hot zones in the flame as a synthesis product through the release of hydrocarbons containing primary tars from wood pyrolysis, formation of secondary tars in an atmosphere with lack of oxygen, PAH formation, and finally release of hydrogen during particle growth thus resulting in a high C/H ratio as indicated in Table 1.

At optimum excess air (regime B), near complete combustion is achieved, if good mixing of combustible gases with air is guaranteed and quenching of the flame is avoided. Consequently, carbonaceous matter in solid and liquid phase is emitted in very small concentrations, while inorganic particles formed from ash constituents are available as particulate matter (PM) in the flue gas and predominantly found as salts.

At high overall excess air (regime A), the combustion temperature decreases, resulting in incomplete combustion. Due to low temperature, the formation of soot and the release of hydrogen is suppressed, resulting in high concentrations of primary and secondary tars formed during pyrolysis consequently leading to condensable organic compounds (COC) in the flue gas with low C/H ratio.

Since ESP operation is ideal at operation at optimum excess air, nowadays applications are often limited to such combustion conditions, while the ESP is often shut-off during unideal combustion conditions.

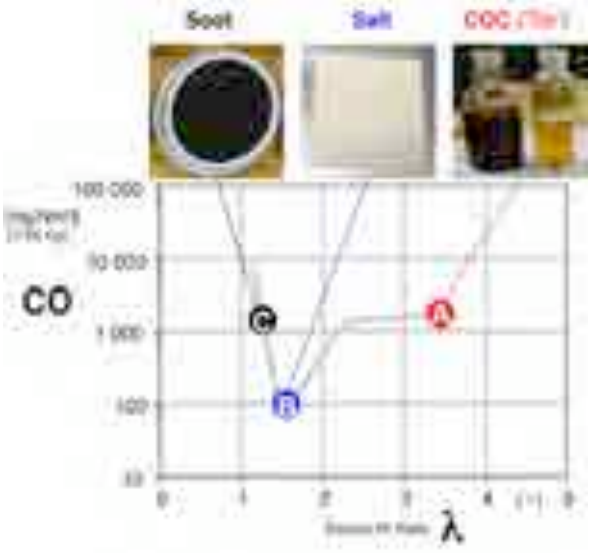


Figure 5: Three regimes of biomass combustion shown in the diagram CO as function of excess air lambda acc. to [11]. The three combustion regimes are related to three different types of combustion particles, i.e., soot, salts, and COC, depending on the level of excess air and other parameters.

4.2 Particle properties

According to the chemical composition and the physical properties, salts are expected to be suitable for ESP operation, while soot may result in re-entrainment and COC may be related to back-corona (Table 1). Due to the release of hydrogen during soot formation, a significantly different molar ratio of soot and COC is expected, thus enabling to identify and distinguish the two types of aerosols from incomplete combustion (Table 1).

Figure 6 shows the combustion conditions and indicated by emissions, temperature, and excess air as well as the resulting particle composition, table 2 shows the results from the chemical analysis, while Figure 7 shows the electrical particle properties. The results confirm, that the particle properties are influenced by the excess air ratio (λ), which enables to distinguish three different combustion regimes.

- At λ = 1.2, a lack of oxygen results in high soot formation (but low content of CO and HC), which leads to re-entrainment of agglomarated particles.
- For λ = 1.55, almost complete combustion is achieved in the pellet boiler thus resulting in mainly inorganic particles.
- By increasing the excess air ratio to 3.5, stable operation at high concentrations of CO and HC is achieved, resulting in COC an leading to back-ionisation, which leads to a slightly reduced precipitation efficiency.

Figure 7 shows the results of analyses of the electrical conductivity as function of the temperature measured from four different types of combustion particles, i.e., soot, salt, and COC from the laboratory equipment, and dust collected in the ESP from a 1 MW industrial wood combustion plant and referred to as "Reference".

As expected, salt particles and reference dust exhibit a favourable conductivity in a relatively broad range of application and hence are potentially well suited for precipitation in ESP. However, the moisture content in the flue gas strongly influences the conductivity of the particle layer and needs to be considered for the design and operation of the ESP. Although measurements are recommended for specific applications, the results in Figure 6 enable a qualitative indication for optimised operation of ESP for different particle types:

Dry flue gas is favourable for salts in the most relevant temperature range up to 200°C, while for COC, reasonable conditions in dry flue gas are only expected at temperatures above 170°C. In wet flue gas, the precipitation of salts becomes critical for temperatures below 120°C. Consequently, a relatively narrow range of optimum operation may result for practical conditions of biomass combustion with varying excess air and varying fuel moisture content.

4.3 Precipitation mechanisms

Since the electrical conductivity influences the formation of dust layers in the electric field, different dust layers may be formed depending on the particle properties. Soot leads to dendritic build-up with a weak adhesion of the agglomerates as shown in Figure 8, which can cause re-entrainment of agglomerated soot particles. Salt forms a homogeneous layer, which can be safely removed by state-of-the-art dedusters. COC may form a homogeneous, but sticky layer, which is difficult to be removed and may cause operational problems.

4.4 Precipitation efficency

Table 3 and Figure 9 show the precipitation efficiencies achieved for the three different particle types. While the expected precipitation of 90% can be easily achieved for salt particles, the precipitation of COC is slightly reduced due to back-corona resulting in a limitation of the electric field or the maximum allowable voltage respectively. For soot, slightly reduced precipitation efficiency is achieved indicated by particle number concentration. However, the precipitation efficiency for soot indicated by mass concentration is far lower (i.e., 22%) than the precipitation efficiency indicated by number concentration, which is due to re-entrainment of agglomerated particles.

The particle size distribution in Figure 10 shows that the distribution mode is reduced by about an order of magnitude with the ESP, while the ESP leads to an increase by almost one order of magnitude of the particles larger than 0.5 micron. This confirms the effect of re-entrainment of agglomerated soot particles. Hence the ESP acts partly as an agglomerator and partly as a precipitator. This effect can be relevant for small-scale ESP for wood stoves and boilers, where precipitation efficiencies by mass of less than 80% are common and where measurements of particle mass concentrations can result in unreliable precipitation efficiencies. With respect to health effects, the re-entrainment of coarse particles can be seen as an improvement in comparison to the emission of primary combustion particles in the size range smaller than 10 micron. Nevertheless, the emission of agglomerated soot particles may have negative local impacts and hence needs to be restricted as well. This effect can potentially limit the applicability of ESP for small scale wood combustion related to high soot concentration in the flue gas.

4.5 Electrical behaviour of ESP

In ESP operation at wood combustion plants, the operator usually has no information about the electric dust conductivity. By looking at the current density as a function of the voltage, conclusions can be drawn about the electric conductivity in case of high resistivity. As shown in Figure 11, back corona can occur for COC, characterized by simultaneous increase of the current at constant or even decreasing voltage. Low resistivity from soot cannot be detected by this method.

Table 1: Chemical and electrical properties and suitability for precipitation in ESP of the three particle types as expected from theory and experiences [1,8,9]. *primary tar: isolating, secondary tar and PAH: semiconductiv.

Particle type Property	Salts	Soot	COC
Molar ratio C/H	–	> 6 – 8	≈1 (< 2)
Electrical conductivity	medium	high	low (electrically insulating)*
Suitability for ESP	ideal	re-entrainment	back-corona

Table 2: Carbon content (1) and elemental composition (2) of the particles
(1) thermal carbon analyses and (2) elemental analyses.

			Soot	Salt	COC
1	**C (Total C)**	**wt.-%**	**51.4**	**15.211**	**45.214**
2	**C**	**wt.-%**	**41.0**	**14.5**	**36.0**
	H	**wt.-%**	0.53	0.45	2.41
	N	**wt.-%**	0.28	0.53	0.73
	S	**wt.-%**	3.12	5.12	1.53
	C/H	[Mol/Mol]	6.44		1.24

Table 3: Precipitation efficiencies measured by mass and number concentration of 'soot', 'salt', and 'COC' as resulting combustion particles for the three different combustion regimes, i.e., low excess air, ideal excess air, and high excess air.

	[Dim.]	low excess air & high temperature	ideal excess air & high temperature	high excess air & low temperature
Particle type		**Soot**	**Salt**	**COC**
Excess air lambda	[–]	1.2	1.55	3.5
CO	[mg/m_n^3] at 13 vol.-% O_2	1000	70	4000
THC	[mg/m_n^3] at 13 vol.-% O_2	20	2	400
PM mass conc. before ESP	[mg/m_n^3] at 13 vol.-% O_2	50	30	50
PM mass conc. after ESP	[mg/m_n^3] at 13 vol.-% O_2	42	3	7
Precipitation efficiency by mass	**[%]**	**16**	**90**	**86**
PM number conc. before ESP	[cm_n^{-3}]	$6.0\ 10^7$	$6.0\ 10^7$	$9.6\ 10^7$
PM number conc. after ESP	[cm_n^{-3}]	$7.5\ 10^6$	$4.8\ 10^6$	$9.0\ 10^6$
Precipitation efficiency by number	**[%]**	**88**	**92**	**90**

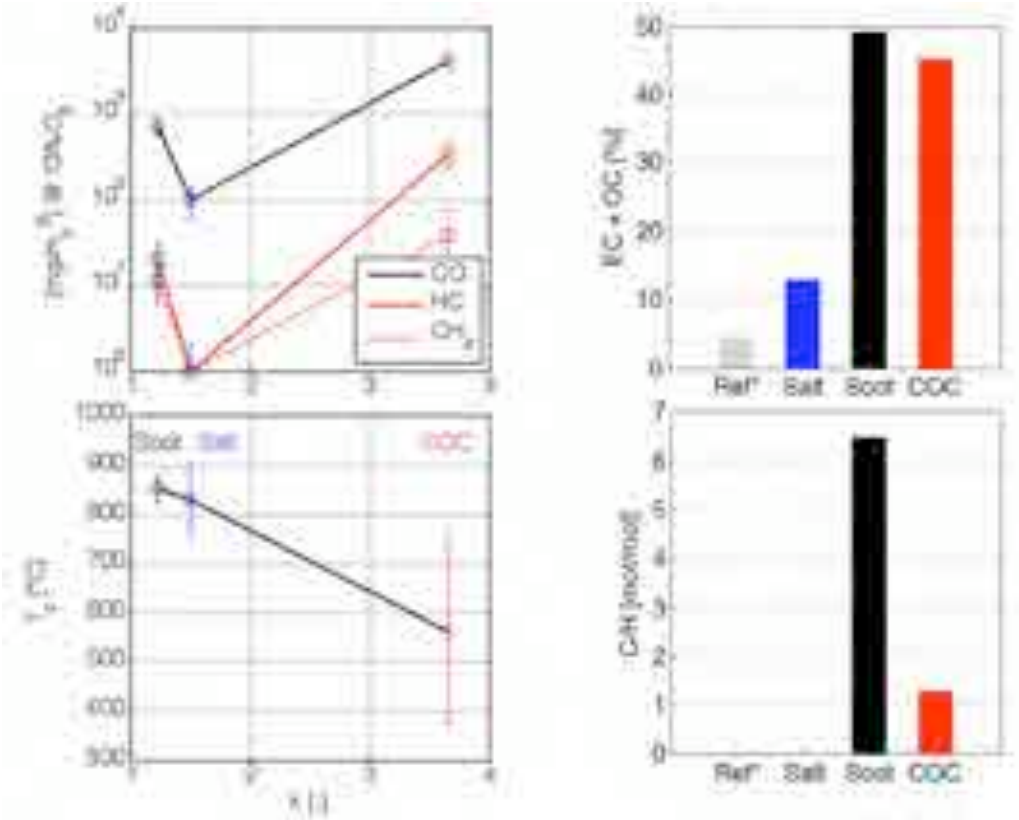


Figure 6: Left: Characteristic of the three operating points maintained with the modified pellet boiler. Right: Results of the chemical analysis of the three particle types. In addition, results from dust sampled in a commercial ESP found after combustion of natural wood chips in an automatic combustion plant are shown and indicated as "Ref" for "Reference".

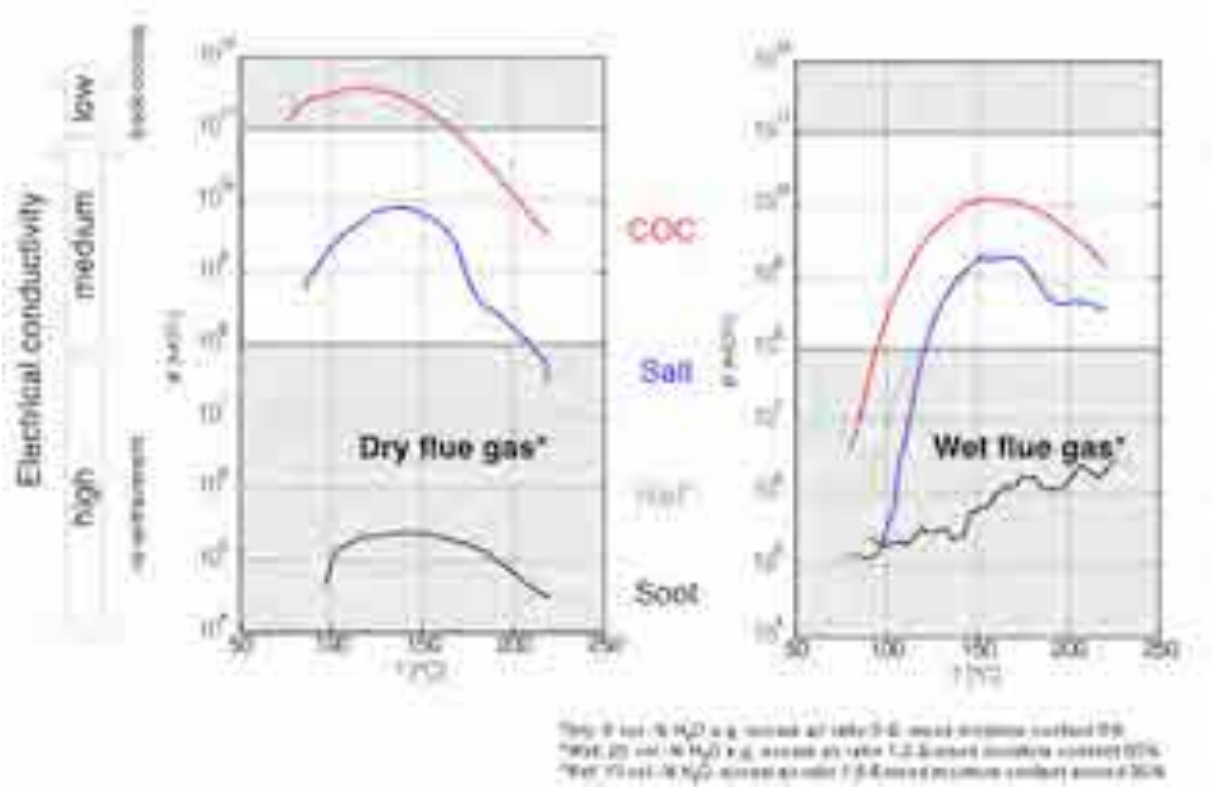


Figure 7: Electrical conductivity measured for soot, salts, and COC sampled in the laboratory equipment during combustion conditions as described. In addition, results from dust sampled in a commercial ESP found after combustion of natural wood chips in an automatic combustion plant are shown and indicated as "Ref" for "Reference". The optimum range for precipitation in ESP is indicated according to Parker [2].

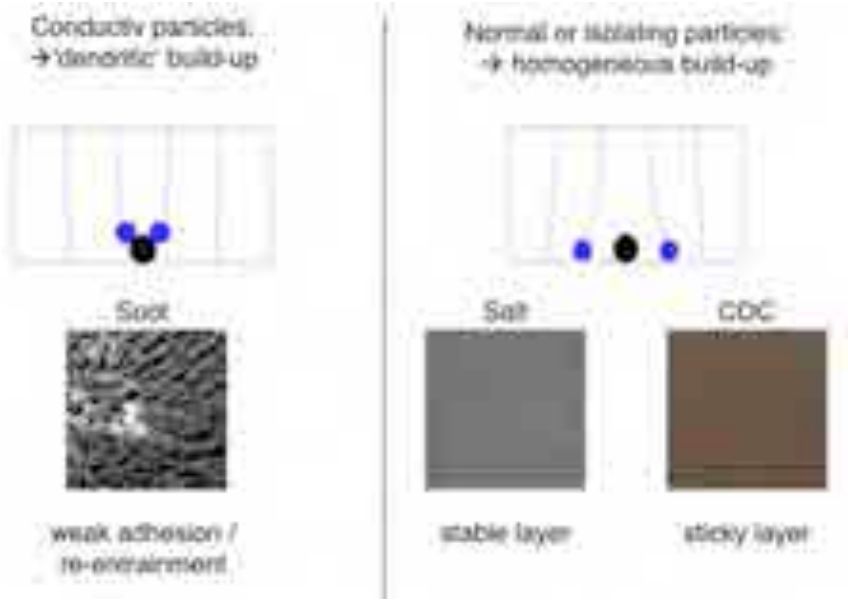


Figure 8: Mechanisms of dust layer built-up due to electric field (acc. to [12]) for conductiv particles (left) and isolating particles (right). The pictures below show the resulting dust layers found in the ESP.
From left to right:
1. Dendritic coarse soot agglomerates from combustion with insufficient air (black carbon, mainly elemental carbon),
2. Homogeneous grey dust layer from combustion with ideal air supply, and
3. Sticky brown dust layer from combustion with high air excess (brown carbon, mainly organic carbon).

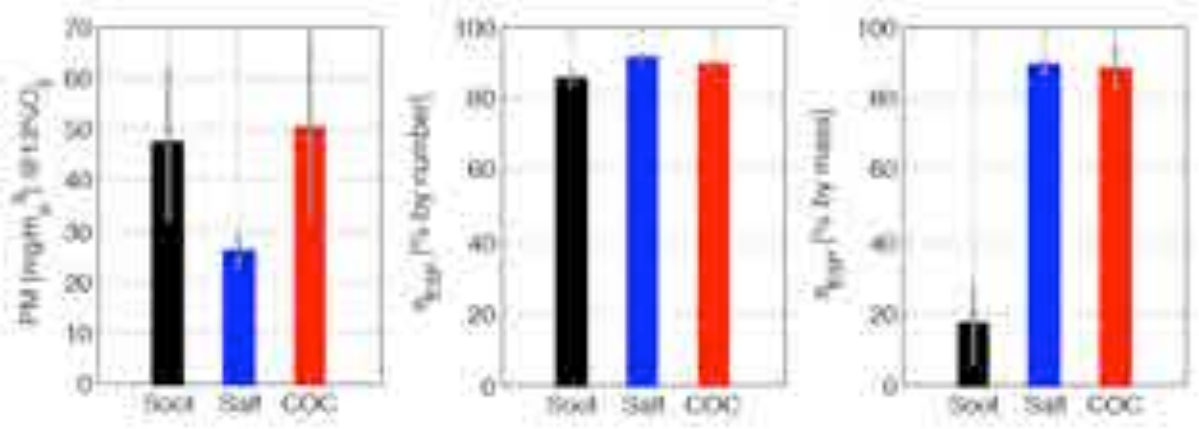


Figure 9: Particle mass concentration in the raw gas from the different combustion regimes measured by gravimetric method, precipitation efficiency measured by particle number concentration, and precipitation efficiency measured by particle mass concentration of 'soot', 'salt' and 'COC'.

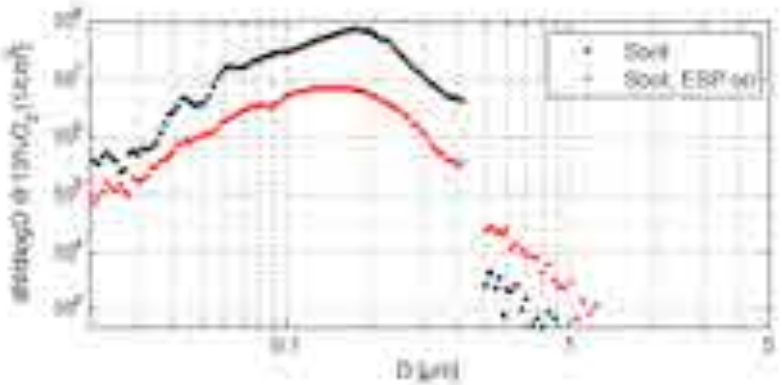


Figure 10: Particle size distribution for soot measured with SMPS and OPC after the laboratory ESP.

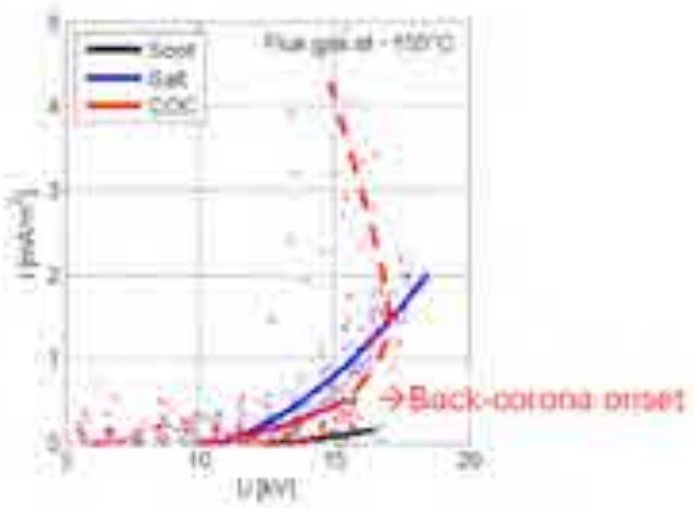


Figure 11: Current density as function of the voltage depending on the particle typ

5 CONCLUSIONS

Particles from different combustion conditions have been collected in a laboratory ESP and were analysed with respect to chemical and electrical properties to deduce recommendations on the ESP design and operation leading to the following conclusions:

- Three different particle types from wood combustion have been identified which correspond to different combustion regimes, i.e.,
  – soot resulting from combustion at high temperature but with low excess air and consequently local lack of oxygen,
  – particles which consist dominantly of mineral matter such as salts found at high combustion temperature and with sufficient local excess air
  – condensable organic compounds (COC) resulting from low temperature combustion conditions at high excess air.
- The three particle types exhibit completely different physical and chemical properties, among which the electrical conductivity is most relevant for ESP operation. The identified properties confirm the particle type and the particle properties as expected from the proposed theory of the particle formation mechanisms.
- Particles from good combustion (mainly inorganic compounds such as salts) exhibit ideal conductivity for ESP.
- Soot reveals high conductivity thus enabling high precipitation efficiency but severe re-entrainment of agglomerated particles
- Condensable organic compounds (COC) exhibit low conductivity thus leading to back-corona which limits ESP operation
- ESP operation for good and stationary conditions during wood combustion with mainly inorganic particles enables uncritical operation, while ESP operation can be critical e.g.
  - during start-up due to COC from low temperatures
  - during throttled air, either due to COC released at low temperatures or due to soot formed at high temperatures in zones with lack of oxygen.
  Both undesired conditions are often found in small scale biomass combustion applications for heating.

These results show, that ESP alone will usually only guarantee low particle emissions when the combustion device is properly operated, while during transient conditions, the clean gas emissions can be increased not only due to increased raw gas concentrations, but additionally due to reduced precipitation efficiency. Detailed information on the influence of combustion conditions on particle characteristics enable improved ESP design and operation for the specific needs for small and medium scale wood combustion devices.

6 RECOMMENDATIONS AND OUTLOOK

ESP availability is crucial and needs to be improved by optimum plant design, system integration, and plant operation based on the following three measures:

1. Optimum design and system integration of combustion and ESP enabling stationary operation, e.g. by plant design with two boilers and two ESP for variable load.
2. Process integrated control of ESP with specific information as indicators for the particle properties
   - flue gas temperature (as today) plus:
   - excess air ratio
   - combustion temperature
   - water content of the fuel
   This increases the operation regime of the ESP.
3. Measures to avoid re-entrainment:
   - Limitation of gas velocity to < 1.5 m/s
   - optimised shape of collecting plates
   - shorter dedusting intervall during re-entrainment regimes.

7 LITERATURE

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Acknowledgments

Swiss Federal Office for Energy (SFOE)
Commission for Technology and Innovation (CTI)

OekoTube Test Report

Tests run August thru September 2013.

Summary

A small scale electrostatic precipitator (ESP) was mounted on the top exterior of a 20 foot tall lined chimney. This chimney was cleaned before use. The charge generator was within a weatherproof box (supplied) that was mounted with adjustable metal bands. A metal "tee" (supplied) of 10" diameter was secured on top of the chimney lining. The collection electrode coming out of the charge generator was centered within the chimney. The collection electrode is approximately 60" long with a weighted end.

A wood boiler connected to the bottom of the chimney was fueled with cord wood at fairly consistent moisture, tree type and quantity. The wood boiler combustion was run at a range of air inlet levels (20%, 40%, 60%, 80%, 100% stoichiometric rates)

A baseline test was run at each range of air inlet level with the electrostatic precipitator "off".

After each test run (both with the ESP off as well as on) the collection electrode was removed with condition and particulate coverage amounts noted. The chimney was also inspected after each run, and condition noted.

Results

More extensive testing is needed; however initial testing demonstrates that with equivalent quantities of wood-the ESP is effective for the capture of particulates for exhausts that are at "starved" stoichiometric levels.

The exhaust flow rate may be too "fast" for more effective particulate capture at the higher "burn" rates.

It is assumed that the increase of resistivity of the ESP collection electrode (or size) would also increase the particulate capture.

Wood Boiler Type

HS Tarm Model 404
Inlet air controlled via valve
Digital temperature probes within firebox and at exhaust
Boiler Pressure Relief Valve (PRV) at 15 PSI- with automatic water recharge

Fuel

2 kg. Hardwood- maple and oak- kindling split to approx.½" either direction.

23 kg. Hardwood- maple and oak
Split wood- no rounds
Typical size- 16" long by 8" square
20% -30% moisture content
No bark

Test Runs

Each start consisted of "warm up" of the wood boiler at room temperature with full air inlet opening- using 2 kg of hardwood kindling- after 30 minutes 23 additional kg of hardwood added to the fuel box and air inlet opening valve adjusted.

Time for each test was noted to nearest 15 minutes- determined when firebox temperature was reduced to 150 degrees F.

The ESP was removed and all particulates lightly brushed with soft cloth to be weighed- and compared against tare weight of cloth.

The ESP and chimney cleaned before each test run.

Outside ambient temperature ranged from 60 to 85 degrees F.

Results

Test	Time	Particulates	Other Notes
20% ESP off	10 hours 30 min.	1.4 grams	Creosote liquid on chimney lining Exhaust Temp at chimney top 120-130 degrees F
20% ESP on	11 hours 5 min.	8.5 grams	Creosote liquid on chimney lining Exhaust Temp at chimney top 120-130 degrees F
40% ESP off	8 hours 15 min.	1.2 grams	Creosote liquid on chimney lining Exhaust Temp at chimney top 125-150 degrees F
40% ESP on	8 hours 15 min.	6.2 grams	Creosote liquid on chimney lining Exhaust Temp at chimney top 125-150 degrees F
60% ESP off	6 hours 45 min.	1.4 grams	No creosote Exhaust Temp at chimney top 140-150 degrees F
60% ESP on	6 hours 30 min.	4.0 grams	No creosote Exhaust Temp at chimney top 140-150 degrees F
80% ESP off	5 hours 15 min.	1.2 grams	No creosote PRV release @ 3 hr. mark Exhaust Temp at chimney top 140-170 degrees F
80% ESP on	5 hours 15 min.	4.8 grams	No creosote PRV release at 3 hr. mark Exhaust Temp at chimney top 140-180 degrees F
100% ESP off	4 hours 15 min.	None observed	No creosote PRV release @ 2 hr. 15 min mark Exhaust Temp at chimney top 150-180 degrees F
100% ESP on	4 hours 30 min.	2 grams (very light)	No creosote PRV release @ 2 hr. mark Exhaust Temp at chimney top 150-180 degrees F