Technical Analysis Report

For the terms and conditions of

Construction Permit AQ1539CPT01

Issued to Alaska Gasline Development Corporation

For the Liquefaction Plant

Alaska Department of Environmental Conservation
Air Permits Program

Prepared by Dave Jones

Reviewed by Aaron Simpson

Preliminary – September 11, 2020

1. INTRODUCTION

This Technical Analysis Report (TAR) provides the Alaska Department of Environmental Conservation's (Department's) basis for issuing Construction Permit AQ1539CPT01 to Alaska Gasline Development Corporation (AGDC) for the Liquefaction Plant. The project triggers Prevention of Significant Deterioration (PSD) review under 18 AAC 50.306 for oxides of nitrogen (NOx), sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter (PM), particulate matter with an aerodynamic diameter not exceeding 10 microns (PM-10), particulate matter with an aerodynamic diameter not exceeding 2.5 microns (PM-2.5), volatile organic compounds (VOCs), and greenhouse gases (GHGs). The project is also classified under 18 AAC 50.316 as a major source of Hazardous Air Pollutants (HAPs) for formaldehyde and ethylbenzene.

1.1. Description of Source

The Liquefaction Plant is a new stationary source located in Southcentral Alaska's Kenai Peninsula, approximately 3 miles southwest of Nikiski and 8.5 miles north of Kenai. The facility is classified under Standard Industrial Classification code 4922 for natural gas transmission and under North American Industrial Classification code 221210 for natural gas distribution.

1.2. Application Description

AGDC submitted an initial application for this project on May 1, 2018. They submitted a response to a Department incompleteness finding on September 24, 2018 and ambient monitoring data on October 17, 2019. Additionally, AGDC submitted several addenda through July 1, 2020, including updated Best Available Control Technology (BACT) and increment analysis information. AGDC is requesting authorization to install and operate simple cycle and combined cycle gas-fired turbines, reciprocating internal combustion engines, a thermal oxidizer, flares, and fuel tanks to support the liquefaction of natural gas.

1.3. Project Description

The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaska's North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.

The emissions units (EUs) at the stationary source will include combined cycle gas-fired turbines for power generation, simple cycle gas-fired turbines for gas compression, a diesel fuel-fired fire water pump, a diesel fuel-fired auxiliary air compressor, a thermal oxidizer to control collected hydrocarbon vapors from condensate storage and loading, flares for control of excess gas, and storage tanks for diesel fuel and gas condensates.

The Liquefaction Facility is designed to process an average stream day rate of 2.7 billion standard cubic feet per day of feed gas and would be able to accommodate compositions of natural gas received from the pre-treatment facilities.

A description of the process is as follows:

Heavy Hydrocarbon Removal – After passing through the mercury removal beds and the gas stream is dehydrated, the gas would pass through a scrub column to remove heavy hydrocarbon components from the gas (which would have already passed through the mercury removal beds and dehydration unit). Heavy hydrocarbons are removed because they would freeze during the liquefaction process. The hydrocarbon liquid stream leaving the bottom of the scrub column would be sent to the Fractionation Unit.

Fractionation Unit – A single Fractionation Unit would serve the three LNG trains. The Fractionation Unit would include three distillation columns, a de-ethanizer, a de-propanizer, and a de-butanizer. The columns would be designed to produce ethane, propane, and stabilized condensate product. Ethane and propane would be reinjected into the feed gas to maximize LNG production. A small amount of ethane and propane would also be used for refrigerant. Condensate would be sent to the condensate storage tank and transported by truck to nearby industrial customers.

Liquefaction – The natural gas would be liquefied using the Propane Precooled Mixed Refrigerant (AP_C3MR™) Process, an Air Products and Chemicals Inc. (APCI) patented technology. In this process, the treated natural gas would first be pre-cooled in successive stages of propane chilling. Subsequent cooling and liquefaction would be achieved by heat exchange against mixed refrigerant, and would be accomplished in the main cryogenic heat exchanger (MCHE). Prior to entering the MCHE, the mixed refrigerant would be pre-cooled/partially condensed. The refrigeration for this pre-cooling would also be provided by multiple stages of propane chilling.

Refrigeration Compressors – Each of the three LNG trains would include two refrigerant compression strings installed in parallel, driven by two natural gas turbines. Total capacity of natural gas turbines driving refrigeration compressors for all trains is approximately 800,000 International Standardization Organization (ISO) horsepower.

Cooling System – The propane and mixed refrigerant would be cooled using air coolers. Fans would pull the air over tube bundles, in turn cooling within the tube bundles. The system would involve a number of electric motor and fan assemblies requiring a plant-wide total of approximately 29,000 brake horsepower. Air-cooled LNG plants are influenced by the variation in the air temperature. The Liquefaction Facility air cooler inlet air dry bulb design temperature is expected to vary between a low ambient of 2 degrees Fahrenheit (°F) and a high ambient of 61 °F. Ambient temperatures affect production rates, resulting in a higher achievable liquefaction rate in the winter months than in the summer.

Boil-off-gas (BOG) Compression – All BOG (i.e., vaporized LNG) generated from the LNG lines, LNG loading pumps, and storage tanks, plus vapor return from LNG loading operations would be compressed and routed to the fuel gas system. BOG generated in excess of fuel gas demand would be recycled to the natural gas stream entering the liquefaction process. BOG from the LNG storage tanks and loading berths would provide the majority of the overall plant fuel needs for operations.

LNG Storage Tanks – LNG from the three liquefaction trains would be stored in two LNG storage tanks. Each of the tanks would be capable of storing approximately 240,000 cubic meters. The LNG storage tanks, capable of storing 480,000 cubic meters (total) would provide a storage capacity of three to four days of production. The tanks would be above ground, providing full containment, with the design consisting of a precast concrete inner tank with a 9-percent nickel bottom and a precast concrete outer tank.

LNG Loading Lines – Loading and circulating piping, from the LNG storage tanks to the loading arm would transfer approximately 12,500 cubic meters of LNG per hour. The LNG loading system would consist of two parallel pipe-in-pipe lines each consisting of a 32-inch outer pipe and a 28-inch inner pipe. The outer pipe serves as a liquid and vapor containment system in the unlikely event of a leak from the inner pipe. A 36-inch vapor return line (not pipe-in-pipe) is also provided, carrying vapors from the liquefied natural gas carriers(LNGCs) GCs back to the BOG compressors. The loading system would be designed to load one LNGC at a time.

Marine Terminal – The Marine Terminal would be constructed adjacent to the LNG Plant in Cook Inlet and would allow LNGCs to dock and load LNG. The marine facilities would include:

> Product loading facility (PLF) that would support the piping that delivers LNG from shore to LNGCs and that would include all of the equipment to dock LNGCs; and
>
> Material offloading facility (MOF) that would be a dock used during Project construction to enable direct deliveries of materials, equipment, modules, and other cargo to minimize the transport of large and heavy loads over road infrastructure.

The PLF would be a permanent facility for the duration of the LNG export operations. The MOF would consist of temporary facilities that would be removed during operations of the LNG Plant. The approach and berths at the MOF would need to be dredged to the depths of -30 feet and -32 feet Mean Lower Low Water (MLLW), respectively. An additional allowance of no more than -2 feet may be required for over-dredge.

The design loading rate is proposed to be 12,500 cubic meters of LNG per hour and the facilities would be designed for loading of one LNGC at a time. However, another LNGC may berth or unberth while loading operations are occurring at the other berth. Vessel refueling is not proposed during operations at the facility. Loading berths would be designed for a range of LNGC sizes to accommodate specific marketing requirements. Based on a nominal 176,000-cubic-meter LNGC design vessel, approximately 21 vessel visits per month would be required to export the produced LNG. The LNGCs would range in size between 125,000 cubic meters (approximately 30 vessel visits per month) and 216,000 cubic meters (approximately 17 vessel visits per month).

2. CLASSIFICATION FINDINGS

Based on the review of the application, the Department finds that:

1. This project is classified under 18 AAC 50.306(a) for beginning actual construction of a new stationary source that is PSD major for NOx, CO, VOC, PM, PM-10, PM-2.5, SO_2, and GHG.

2. This project is also classified under 18 AAC 50.316 as a major source of HAPs for formaldehyde and ethylbenzene.

3. APPLICATION REVIEW FINDINGS

Based on the review of the application, the Department finds that:

1. The Liquefaction Plant is classified as a major stationary source under 40 C.F.R. 52.21(b)(1)(i)(b) because the stationary source has the potential to emit 250 tpy or more of a regulated air pollutant.
2. The Liquefaction Plant has potential NOx, CO, PM, PM-10, PM-2.5, SO_2, and VOC emissions that are PSD significant, per 40 C.F.R. 52.21(b)(23)(i). The GHG are subject to regulation per 40 C.F.R. 52.21(b)(49)(iv)(a). Therefore, the project requires a PSD permit under 18 AAC 50.306(a) for these pollutants.
3. AGDC did not model the secondary emissions occurring during the construction phase of the project. Instead, the Department is imposing a requirement to construct and maintain vertical, uncapped exhaust stacks on all temporary camp engines (Condition 9.1), a fugitive dust control plan (Condition 10.1), and a requirement to install and operate PM-10 and PM-2.5 ambient air monitoring stations (Condition 10.2) throughout the construction phase. For more information see the Modeling Report in Appendix D.
4. AGDC included a BACT analysis for all of the applicable emission unit types at the stationary source.
5. For compliance with the BACT emission limits the Department required initial source testing for larger units with add-on controls. BACT limits for EUs 1 through 6 and 7 through 10 require source testing on two like kind units. Smaller units that are not likely to exceed the BACT limits are required to either submit to the Department a manufacturer’s guarantee that the units will meet the BACT limits or source test the units to show they meet the numerical BACT emissions limits.
6. The PTE and BACT limits for all gas-fired EUs use a total sulfur content not to exceed 16 ppmv.

4. EMISSIONS SUMMARY AND PERMIT APPLICABLITY

Table 10 shows the emissions summary and permit applicability with assessable emissions from the stationary source, listed in tons per year (tpy). Emission factors and detailed calculations are provided in Appendix A.

A summary of the potential to emit (PTE) and assessable PTE, as determined by the Department, is shown in Table 10 below.

Table 10: Emissions Summary and Permit Applicability

Parameter	Emissions (tpy)					
	NOx	CO	VOC	PM-2.5	PM-10	SO_2
PTE Authorized Under AQ1539CPT01	3,684.9	11,927.4	24,654.8	1,303.3	1,303.3	182.6
Title V Permit Thresholds	100	100	100	100	100	100
Title V Permit Required?	Yes	Yes	Yes	Yes	Yes	Yes

Parameter	Emissions (tpy)					
	NOx	CO	VOC	PM-2.5	PM-10	SO_2
Assessable Emissions	3,685	11,927	24,655	1,303	1,303	183
	41,753					

Table Notes:
41,753 tons is a conservative estimate that includes flaring at maximum capacity for 500 hours per year for the wet and dry flares and 144 hours per year for the low pressure flare. Without the inclusion of maximum flaring the total assessable emissions is 2,204 tons.
PM-10 emissions include PM-2.5 emissions. Therefore, PM-2.5 is not counted in total assessable emissions.
Fuel Gas Sulfur Content: 16 ppmv used for calculating SO_2 emissions from all gas-fired EUs.
Diesel Fuel Sulfur Content: 15 ppmw used for calculating SO_2 emissions from all diesel-fired EUs

Table 11: Major Source and PSD Review Applicability

Parameter	NOx	CO	VOC	PM-2.5	PM-10	PM	SO_2	CO_2e[1]
PTE for AQ1539CPT01 excluding fugitive emissions	3,684.9	11,927.4	24,636.8	1,303.3	1,303.3	1,303.3	182.6	8,572,968
PSD Major Source Threshold	250	250	250	250	250	250	250	N/A
Major Source Triggered?	Yes	Yes	Yes	Yes	Yes	Yes	No	No
PSD Significant Emissions Rates	40	100	40[3]	10[2]	15	25	40	75,000
PSD Review Triggered?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Table Notes:
[1] GHG are subject to regulation because the stationary source is major for a non-GHG pollutant and the carbon dioxide equivalent (CO_2e) is at least 75,000 tpy.
[2] PSD review for PM-2.5 can also be triggered by NOx and SO_2 precursor emissions, as specified under 40 C.F.R. 52.21(b)(23)(i).
[3] VOC acts as a surrogate for ozone (O_3). In addition to the VOC emissions trigger, PSD review for O_3 can also be triggered by NOx emissions, as specified under 40 C.F.R. 52.21(b)(23)(i).

5. PERMIT CONDITIONS

The bases for the standard and general conditions imposed in Construction Permit AQ1539CPT01 are described below.

Section 1: Emissions Unit Inventory

The EUs authorized and/or restricted by this permit are listed in Table 1 of the permit. Unless otherwise noted in the permit, the information in Table 1 is for identification purposes only. Condition 1 is a general requirement to comply with AS 46.14 and 18 AAC 50 when installing a replacement EU.

Section 2: Emission Fees

Condition 3, Fee Requirements

18 AAC 50.306(d)(2) requires the Department to include a requirement to pay fees in accordance with 18 AAC 50.400 – 18 AAC 50.420 in each PSD permit issued under 18 AAC 50.306.

Conditions 4 and 5, Assessable Emissions

18 AAC 50.346(b)(1) requires the Department to include the Standard Permit Condition (SPC) I language for construction permits. However, for Construction Permit AQ1539CPT01 the Department modified the SPC I language to include a website address for submitting emission estimates through the Air Online Services (AOS) System. The Department also updated its mailing/delivery addresses.

As indicated by Footnote 2, if the stationary source has not commenced construction or operation on or before March 31, the Permittee is required to submit a transmittal letter certified by the responsible official under 18 AAC 50.205 indicating that the assessable emissions for the source are zero for the previous fiscal year.

Section 3: State Emission Standards

Condition 6, Visible Emissions

Visible emissions, excluding condensed water vapor, from an industrial process or fuel-burning equipment may not reduce visibility through the effluent by more than 20 percent averaged over six consecutive minutes, under 18 AAC 50.055(a)(1). Per 18 AAC 50.990(39), “fuel-burning equipment” does not include mobile internal combustion engines (e.g., NREs).

The Department is requiring an initial compliance demonstration within 60 days of startup of the new diesel-fired EUs 11 and 12. For the fuel gas-fired EUs 1 through 10 and 13, the Department is requiring a statement in each operating report that the EUs fired only fuel gas as fuel. For the flaring EUs 14 through 20 the Department is requiring an initial Method 9 observation during the first daylight flare event.

Conditions 7, Particulate Matter (PM)

Particulate Matter emitted from an industrial process or fuel burning equipment may not exceed 0.05 grains per cubic foot of exhaust gas (gr/dscf), averaged over three hours, under 18 AAC 50.055(b).

Experience has shown there is a correlation between opacity and particulate matter. 20 percent visible emissions would normally comply with the 0.05 gr/dscf. As such, compliance with opacity limits is included as a surrogate method of assuring compliance with the PM standards. With the exception of the limited use diesel engines EUs 11 and 12, all other fuel burning EUs at the stationary source will combust natural gas with a total sulfur content not to exceed 16 ppmv. Particulate emissions from the combustion of low sulfur natural gas is relatively insignificant. Therefore, the Department did not impose testing and MR&R conditions for these units, other than reporting that natural gas was the only fuel combusted in the EU during the reporting period.

Condition 8, Sulfur Compound Emissions

Sulfur compound emissions from an industrial process or fuel burning equipment may not exceed 500 ppm averaged over a period of three hours, under 18 AAC 50.055(c).

Calculations show that fuel oil with sulfur content less than 0.74 percent by weight will comply with the state emissions standard. Calculations show that fuel gas with sulfur content less than 4,000 parts per million by volume will comply with the state standards. The Permittee demonstrates compliance with Condition 8 by complying with the ambient air quality protection requirement Conditions 11.1 and 11.2, which require combusting only ULSD (0.0015 percent sulfur by weight) and firing only fuel gas with a total sulfur content of no more than 16 ppmv.

Section 4: Ambient Air Quality Protection Requirements

Conditions 9 – 12

18 AAC 50.010 contains the ambient air quality standards, and the Department will include conditions to protect these standards when warranted. The Department determined that conditions are warranted to protect the 1-hour and annual NO_2; 24-hour PM-10; 24-hour and annual PM-2.5; 1-hour and 8-hour CO; and 1-hour, 3-hour, 24-hour, and annual SO_2 AAAQS for the reasons described in Appendix D of this TAR.

Section 5: Best Available Control Technology

Conditions 13 – 18

The project triggers PSD review under 18 AAC 50.306 for NOx, SO_2, CO, PM, PM-10, PM-2.5, VOCs, and GHGs. The Department performed a BACT analysis of all the available control options for equipment emitting the triggered pollutants listed above. The BACT evaluation process selects the best pollutant control option based on feasibility, economics, energy, and other impacts. The full BACT analysis is contained in Appendix B of this TAR and a summary of the BACT analysis is contained in Appendix C of this TAR.

Section 6: General Recordkeeping, Reporting, and Certification Requirements

Condition 19, Certification

18 AAC 50.205 requires the Permittee to certify any permit application, report, affirmation, or compliance certification submitted to the Department. This requirement is reiterated as a standard permit condition in 18 AAC 50.345(j). Construction Permit AQ1539CPT01 uses the standard condition language, but also expands it by allowing the Permittee to provide electronic signatures.

Condition 20, Submittals

Condition 20 clarifies where the Permittee should send their reports, certifications, and other submittals required by the permit. The Department included this condition from a practical perspective rather than a regulatory obligation.

Condition 21, Information Requests

AS 46.14.020(b) allows the Department to obtain a wide variety of emissions, design and operational information from the owner and operator of a stationary source. This statutory provision is reiterated as a standard permit condition in 18 AAC 50.345(i). The Department used the standard language in Construction Permit AQ1539CPT01.

Condition 22, Recordkeeping Requirements

The condition restates the regulatory requirements for recordkeeping, and supplements the recordkeeping defined for specific conditions in the permit. The records being kept provide an evidence of compliance with this requirement.

Condition 23, Excess Emission and Permit Deviation Reports

This condition reiterates the notification requirements in 18 AAC 50.235(a)(2) and 18 AAC 50.240 regarding unavoidable emergencies, malfunctions, and excess emissions. Also, the Permittee is required to notify the Department when emissions or operations deviate from the requirements of the permit. The Department used the Standard Condition III language, but with updated web-links.

Condition 24, Operating Reports

The Department mostly used the Standard Operating Permit Condition VII language for the operating report condition. However, the Department modified or eliminated the Title V only aspects in order to make the language applicable for a construction permit.

Condition 25, Air Pollution Prohibited

18 AAC 50.110 prohibits any emission which is injurious to human health or welfare, animal or plant life, or property, or which would unreasonably interfere with the enjoyment of life or property. Condition 25 reiterates this prohibition as a permit condition. The Department used the Standard Permit Condition II language for Minor Permit AQ1539CPT01.

Condition 26, Emission Inventory Reporting

18 AAC 50.346(b)(8) requires the Department to include the SPC XV emission inventory language for construction permits. 18 AAC 50.346(b)(9) requires the Department to include the SPC XVI Emission Inventory Form (Attachment 3) for construction permits. The Department used the language in SPC XV for the permit condition, but corrected the emissions threshold amount for Pb in Condition 26.2a, from 5 TPY to 0.5 TPY actual emissions. The Department has also added Conditions 26.4a, 26.4b, and updated the submittal requirements in the Emission Inventory Form to clarify the requirements for report submittal using the Department's Air Online Services (AOS) system, or using email, or mailing out a hard copy if the AOS system is not available.

Section 7: Standard Permit Conditions

Conditions 27 – 32

As required under 18 AAC 50.345, the Department may include the standard permit conditions set out in subsections (c)(1) and (2), and (d) through (o), as applicable for a minor or construction permit. As required under 18 AAC 50.346, the Department will include the standard permit conditions set out in this subsection in each construction permit or Title V permit, unless the Department determines that emissions unit-specific or stationary source-specific conditions more adequately meet the requirements of this chapter, or that no comparable condition is appropriate for the stationary source or emissions unit.

The Department included all of the minor permit-related standard conditions of 18 AAC 50.345 in Construction Permit AQ1539CPT01. The Department incorporated these standard conditions as follows:

- 18 AAC 50.345(c)(1) and (2) is incorporated as Condition 27 of Section 7 (Standard Permit Conditions);
- 18 AAC 50.345(d) through (h) is incorporated as Conditions 28 through 32, respectively, of Section 7 (Standard Permit Conditions);
- As previously discussed, 18 AAC 50.345(i) is incorporated as Condition 21 and 18 AAC 50.345(j) is incorporated as Condition 19 of Section 6 (Recordkeeping, Reporting, and Certification Requirements); and
- 18 AAC 50.345(k) is incorporated as Condition 33, and 18 AAC 50.345(l) through (o) is incorporated as Conditions 36 through 39, respectively, of Section 8 (General Source Testing Requirements). See the following discussion.

Section 8: General Source Test Requirements

Conditions 33 – 39

AS 46.14.180 states that monitoring requirements must be, "based on test methods, analytical procedures, and statistical conventions approved by the federal administrator or the department or otherwise generally accepted as scientifically competent." The Department incorporated this requirement as follows:

- Condition 34 requires the Permittee to conduct their source tests under conditions that reflects the actual discharge to ambient air; and
- Condition 35 requires the Permittee to use specific EPA reference methods when conducting a source test.

Section 8 also includes the previously discussed standard conditions for source testing.

6. PERMIT ADMINISTRATION

Construction Permit AQ1539CPT01 is the initial permit for the Liquefaction Plant. Alaska Gasline Development Corporation may therefore operate in accordance with Construction Permit AQ1539CPT01 upon issuance.

Appendix A: Emissions Calculations

Table 12 presents details of the EUs, their characteristics, and emissions. Potential emissions are estimated using maximum annual operation for all fuel burning equipment as defined in 18 AAC 50.990(39) subject to any operating limits.

Table 12: Detailed Permanent EU Inventory and Potential to Emit (tpy)

EU ID	Emissions Unit Description	Rating		Annual Operating Hours	NOx CO EF Units	NO_x		CO		VOC PM-2.5 PM-10 EF Units	VOC		PM_{10}		$PM_{2.5}$		SO_2	CO_2e
						EF	tpy	EF	tpy		EF	tpy	EF	tpy	EF	tpy	tpy	1,000 tpy
1[1]	Train 1a Simple Cycle Treated Gas Compressor Turbine	1,113	MMBtu/hr	8760	ppmv	9	156.74	5	53.01	lb/MMBtu	0.0022	10.91	0.0070	34.29	0.0070	34.29	12.15	570.84
2[1]	Train 1b Simple Cycle Treated Gas Compressor Turbine	1,113	MMBtu/hr	8760	ppmv	9	156.74	5	53.01	lb/MMBtu	0.0022	10.91	0.0070	34.29	0.0070	34.29	12.15	570.84
3[1]	Train 2a Simple Cycle Treated Gas Compressor Turbine	1,113	MMBtu/hr	8760	ppmv	9	156.74	5	53.01	lb/MMBtu	0.0022	10.91	0.0070	34.29	0.0070	34.29	12.15	570.84
4[1]	Train 2b Simple Cycle Treated Gas Compressor Turbine	1,113	MMBtu/hr	8760	ppmv	9	156.74	5	53.01	lb/MMBtu	0.0022	10.91	0.0070	34.29	0.0070	34.29	12.15	570.84
5[1]	Train 3a Simple Cycle Treated Gas Compressor Turbine	1,113	MMBtu/hr	8760	ppmv	9	156.74	5	53.01	lb/MMBtu	0.0022	10.91	0.0070	34.29	0.0070	34.29	12.15	570.84
6[1]	Train3b Simple Cycle Treated Gas Compressor Turbine	1,113	MMBtu/hr	8760	ppmv	9	156.74	5	53.01	lb/MMBtu	0.0022	10.91	0.0070	34.29	0.0070	34.29	12.15	570.84
7[2]	Power Generation Turbines	384	MMBtu/hr	8760	ppmv	9	52.89	5	17.89	lb/MMBtu	0.0022	3.76	0.0070	11.83	0.0070	11.83	4.19	196.95
8[2]	Power Generation Turbines	384	MMBtu/hr	8760	ppmv	9	52.89	5	17.89	lb/MMBtu	0.0022	3.76	0.0070	11.83	0.0070	11.83	4.19	196.95
9[2]	Power Generation Turbines	384	MMBtu/hr	8760	ppmv	9	52.89	5	17.89	lb/MMBtu	0.0022	3.76	0.0070	11.83	0.0070	11.83	4.19	196.95
10[2]	Power Generation Turbines	384	MMBtu/hr	8760	ppmv	9	52.89	5	17.89	lb/MMBtu	0.0022	3.76	0.0070	11.83	0.0070	11.83	4.19	196.95
11[3]	Diesel Firewater Pump Engine	575	hp	500	g/hp-hr	3.56	1.13	3.25	1.03	g/hp-hr	0.19	0.059	0.19	0.059	0.19	0.059	0.0014	0.16
12[4]	Auxiliary Air Compressor Engine	300	hp	500	g/hp-hr	0.45	0.74	3.26	0.54	g/hp-hr	0.21	0.035	0.022	0.004	0.022	0.004	0.0007	0.086
13[5]	Thermal Oxidizer	6.0	MMBtu/hr	8760	g/hp-hr	0.55	1.45	0.082	2.17	g/hp-hr	0.0054	0.14	0.0075	0.20	0.0075	0.20	0.072	3.08
14[6]	Dry Ground Flare #1 (Pilot/Purge)	7.15	MMBtu/hr	8760	lb/MMBtu	0.068	2.13	0.31	9.71	lb/MMBtu	0.66	20.67	0.028	0.88	0.028	0.88	0.076	3.67
	Dry Ground Flare #1 (Maximum)	59,992	MMBtu/hr	500	lb/MMBtu	0.068	1,019.86	0.31	4,649.38	lb/MMBtu	0.66	9,898.68	0.028	423.25	0.028	423.25	37.38	1,756.22
15[6]	Wet Ground Flare #1 (Pilot/Purge)	2.25	MMBtu/hr	8760	lb/MMBtu	0.068	0.67	0.31	3.06	lb/MMBtu	0.66	6.50	0.028	0.28	0.028	0.28	0.025	1.15
	Wet Ground Flare #1 (Maximum)	14,020	MMBtu/hr	500	lb/MMBtu	0.068	238.34	0.31	1,086.55	lb/MMBtu	0.66	2,313.30	0.028	98.91	0.028	98.91	8.74	410.43
16[6]	Dry Ground Flare #2 (Pilot/Purge)	7.15	MMBtu/hr	8760	lb/MMBtu	0.068	2.13	0.31	9.71	lb/MMBtu	0.66	20.67	0.028	0.88	0.028	0.88	0.076	3.67

	Dry Ground Flare #2 (Maximum)	59,992	MMBtu/hr	500	lb/MMBtu	0.068	1,019.86	0.31	4,649.38	lb/MMBtu	0.66	9,898.68	0.028	423.25	0.028	423.25	37.38	1,756.22
17[6]	Wet Ground Flare #2 (Pilot/Purge)	2.25	MMBtu/hr	8760	lb/MMBtu	0.068	0.67	0.31	3.06	lb/MMBtu	0.66	6.50	0.028	0.28	0.028	0.28	0.025	1.15
	Wet Ground Flare #2 (Maximum)	14,020	MMBtu/hr	500	lb/MMBtu	0.068	238.34	0.31	1,086.55	lb/MMBtu	0.66	2,313.30	0.028	98.91	0.028	98.91	8.74	410.43
18[6]	Dry Ground Flare #3 (Pilot/Purge)	7.15	MMBtu/hr	8760	lb/MMBtu	0.068	2.13	0.31	9.71	lb/MMBtu	0.66	20.67	0.028	0.88	0.028	0.88	0.076	3.67
	Dry Ground Flare #3 (Maximum)	59,992	MMBtu/hr	500	lb/MMBtu	0.068	1,019.86	0.31	4,649.38	lb/MMBtu	0.66	9,898.68	0.028	423.25	0.028	423.25	37.38	1,756.22
19[6]	Wet Ground Flare #3 (Pilot/Purge)	2.25	MMBtu/hr	8760	lb/MMBtu	0.068	0.67	0.31	3.06	lb/MMBtu	0.66	6.50	0.028	0.28	0.028	0.28	0.025	1.15
	Wet Ground Flare #3 (Maximum)	14,020	MMBtu/hr	500	lb/MMBtu	0.068	238.34	0.31	1,086.55	lb/MMBtu	0.66	2,313.30	0.028	98.91	0.028	98.91	8.74	410.43
20[6]	Elevated LP Flare (Pilot/Purge)	10.5	MMBtu/hr	8760	lb/MMBtu	0.068	3.13	0.31	14.26	lb/MMBtu	0.66	30.35	0.028	1.30	0.028	1.30	0.22	5.39
	Elevated LP Flare (Maximum)	997.5	MMBtu/hr	144	lb/MMBtu	0.068	5.14	0.31	22.42	lb/MMBtu	0.66	47.40	0.028	2.03	0.028	2.03	0.20	8.77
21[7]	Gas Condensate Storage Tank	457,890	gal	N/A	N/A													
22[7]	Off-Spec Gas Condensate Storage Tank	126,904	gal	N/A	N/A													
23[7]	Gas Condensate Loading System	1,000	gal	N/A	N/A													
24 – 26[8]	Diesel Storage Tanks	4,204	gal (total)	N/A	N/A							0.0015						
N/A	Other Fugitive Emissions	N/A	N/A	N/A	N/A							17.96						2.39
Total Emissions (Without Maximum Flare)							**1,168.5**		**455.6**			**230.8**		**259.0**		**259.0**	**90.4**	**4,242.31**
Total Emissions (With Maximum Flare)							**3,684.9**		**11,927.4**			**24,654.8**		**1,303.3**		**1,303.3**	**182.6**	**8,575.64**

Table Notes:
Fuel Gas Heat Content (HHV): 1,087 Btu/scf
Fuel Gas Sulfur Content: 16 ppmv used for calculating SO_2 emissions from all gas-fired EUs.
Diesel Fuel Sulfur Content: 15 ppmw used for calculating SO_2 emissions from all diesel-fired EUs.
CO_2e emissions calculated using the emission factors for burning natural gas and diesel fuel in 40 CFR Part 98: Mandatory Greenhouse Gas Reporting. The total CO_2e emissions rate is calculated with the equation $CO_2(1) + CH_4(25) + N_2O(298)$.
[1] NOx EF provided by Permittee. CO EF selected from RBLC research for large simple cycle gas-fired turbines with oxidation catalysts. PM-10 and PM-2.5 EFs are the total particulate EF for gas turbines from AP-42 Table 3.1-2a. VOC EF from AP-42 Table 3.1-2a.
[2] NOx EF provided by Permittee. CO emission factor selected from RBLC research for large combined cycle gas-fired turbines with oxidation catalysts. PM-10 and PM-2.5 EFs are the total particulate EF for gas turbines from AP-42 Table 3.1-2a. VOC EF from AP-42 Table 3.1-2a.
[3] NOx, CO, VOC, PM-10, and PM-2.5 EFs are EPA Tier 3 with a 25% not to exceed factor of safety. NOx is assumed to be 95% of NMHC + NOx, and VOC is 5% of NMHC + NOx.
[4] EFs are from EPA Tier 4 Final. NOx, VOC (NMHC), PM-10, and PM-2.5 use a 50% not to exceed factor of safety. CO uses a 25% not to exceed factor of safety. See 40 C.F.R. 1039.101(e) for when to use 50% not to exceed factor of safety.
[5] NOx EF is average EF of low NOx burner equipped thermal oxidizers in the RBLC. VOC EF from Texas Commission on Environmental Quality (TCEQ) NSR Emission Calculations for Vapor Oxidizers guidance document. CO, PM-10, and PM-2.5 EFs are from AP-42, Tables 1.4-1 and 1.4-2, for natural gas combustion in external combustion sources, referenced in TCEQ NSR Emission Calculations for Vapor Oxidizers guidance document.

[6] NOx EF from AP-42 Table 13.5-1. PM-10, and PM-2.5 EFs from AP-42 Table 13.5-1 for soot (lightly smoking flare). CO and VOC EF from AP-42 Table 13.5-1.
[7] Emissions from the condensate storage tanks and loading system are captured and routed to the thermal oxidizer EU 13.
[8] VOC PTE calculated using EPA's Tanks software.

Appendix B: Best available Control Technology

1.0 INTRODUCTION

The Alaska Gasline Development Corporation's (AGDC's) Liquefaction Plant triggered Prevention of Significant Deterioration (PSD) requirements for carbon monoxide (CO), oxides of nitrogen (NOx), sulfur dioxide (SO_2), particulate matter (PM), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM-10), particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers (PM-2.5), volatile organic compounds (VOC), and greenhouse gases (GHG). This appendix includes the Department of Environmental Conservation's (Department's) review of AKLNG Liquefaction Plant's Best Available Control Technology (BACT) analysis for CO, NOx, SO_2, PM, PM-10, PM-2.5 (the Department will refer to PM, PM-10, and PM-2.5 collectively as particulates in this BACT analysis), VOC, and GHG for its technical accuracy and adherence to accepted engineering cost estimation practices.

2.0 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 C.F.R. 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 Liquefaction Plant that emit CO, NOx, SO_2, particulates, VOC, and GHG, establish emission limits which represent BACT, and assess the level of monitoring, recordkeeping, and reporting requirements (MR&Rs) necessary to ensure AGDC 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 2-1 presents the EUs subject to BACT review.

Table 2-1: EUs Subject to BACT Review

EUs	Description of EU
1 – 6	Compressor Turbines (Simple Cycle)
7 – 10	Power Generation Turbines (Combined Cycle)
11 – 12	Compression Ignition Engines
13 – 20	Vent Gas Disposal (Flare/Thermal Oxidizer)
21 – 26	Fuel Tanks (Diesel and Condensates)

Five-Step BACT Determinations

The following sections explain the steps used to determine BACT for CO, NOx, SO_2, Particulates, VOC, and GHG for the applicable equipment.

Step 1 Identify All Potentially Available Control Options

The Department identifies all available control options 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, CO, SO_2, Particulates, VOC, and GHG emissions from equipment similar to those listed in Table 2-1.

Step 2 Eliminate Technically Infeasible Control Options:
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 options deemed technically infeasible due to physical, chemical, and engineering difficulties.

Step 3 Rank Remaining Control Technologies by Control Effectiveness
The Department ranks the remaining control options 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 permit application about the control efficiency, emission rate, emission reduction, cost, environmental, and energy impacts for each option to decide the final level of control. The applicant must present an objective evaluation of both the beneficial and adverse energy, environmental, and economic impacts. An applicant proposing 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.

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 Liquefaction Plant’s BACT analysis and made BACT determinations for NOx, CO, SO_2, Particulates, VOC, and GHG for various EUs based on the information submitted by AGDC in their application, information from vendors, suppliers, sub-contractors, RBLC, and a comprehensive internet search.

3.0 COMPRESSOR TURBINES

The Liquefaction Plant will use six simple cycle natural gas-fired turbines (EUs 1 – 6, make and model yet to be selected) for the three compressors trains (LNG trains), with two turbines used for each LNG train. Each turbine is planned to have a nominal capacity of approximately 1,113 MMBtu/hr heat input, for a total heat input rating of 6,678 MMBtu/hr. The compressor turbines will emit CO, NOx, SO_2, particulates, VOC, and GHG. The following sections provide the BACT review for each of these pollutants.

3.1 NOx

Possible NOx emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.110: large simple cycle natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 3-1.

Table 3-1: NOx Controls for Large Simple Cycle Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits (ppmv)
Selective Catalytic Reduction	11	2.5 – 5
Dry Low NOx Combustors	38	9 – 25
Water Injection	5	20 – 25

Step 1 – Identify NOx Control Technologies for Compressor Turbines

From research, the Department identified the following technologies as available for control of NOx emissions from gas-fired simple cycle combustion turbines rated at 25 MW or greater:

(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. The operating temperature of conventional SCR systems ranges from 400 degrees Fahrenheit (°F) to 800°F. High temperature SCR relies on special material reaction grids and can operate at higher temperature ranges between 700°F to 1,075°F. High temperature SCR is most frequently installed on simple cycle turbines. Depending on the overall NH_3-to-NOx ratio, removal efficiencies are generally 80 to 90 percent. The Department considers SCR a technically feasible control technology for large simple cycle gas-fired turbines.

(b) Dry Low NOx (DLN)

DLN combustors (marketed under many similar names such as SoLoNOx or DLE) utilize multistage premix combustors where the air and fuel is mixed at a lean (high oxygen) fuel-to-air ratio. The excess air in the lean mixture acts as a heat sink, which lowers peak combustion temperatures and also ensures a more homogeneous mixture avoiding localized “hot spots”, both resulting in greatly reduced NOx formation rates. DLN combustors have the potential to reduce NOx emissions by 40 to 60%. In the Department’s search of the RBLC database, the majority of large simple cycle natural gas-fired combustion turbines used DLN as the primary control method for NOx emissions and contained a BACT limit of 9 parts per million by volume (ppmv). Note that 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 considers DLN a technically feasible control technology for large simple cycle gas-fired turbines.

(c) Water/Steam Injection (ULSD)
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, incurring additional costs. Water/steam injection also increases CO emissions as it lowers the combustion temperature. Depending on baseline uncontrolled NOx levels, water or steam injection can reduce NOx by 60% or more. Water/steam injection is a proven technology for NOx emissions reduction from turbines. The Department considers water/steam injection a technically feasible control technology for large simple cycle gas-fired turbines.

(d) 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 simple cycle turbines exhaust gas normally ranges from 800°F to 1,000°F, achieving the required reaction temperature is the main difficulty for application of SNCR to turbines. The Department's research did not identify SNCR as a technology used to control NOx emissions from turbines installed at any facility. Hence the Department considers SNCR as a technically infeasible control technology for the large simple cycle gas-fired turbines.

(e) 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. 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. Turbines 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 turbines installed at any facility. Hence the Department considers NSCR as a technically infeasible control technology for the large simple cycle gas-fired turbines.

(f) SCONOX™

SCONOX™ is a new catalytic absorption technology developed by Goal Line Environmental Technologies, Inc. to treat exhaust gas with a potassium carbonate coated catalyst, reducing NOx to N_2. The catalyst also oxidizes CO to CO_2, and NO and NO_2 to potassium nitrates (KNO_3). The catalyst is regenerated by passing dilute H_2 over it which converts the KNO_2 and KNO_3 to K_2CO_3, water, and N_2. One disadvantage of SCONOX™ is that the catalyst is very sensitive to sulfur in the fuel. For fuel gas sulfur content exceeding 30 ppmv, a sulfur adsorption catalyst must be installed upstream of the SCONOX™ catalyst to remove sulfur. No known installations exist in low ambient temperature settings or on turbine arrangements in industrial settings. The Department's research did not identify facilities using SCONOX™ to control NOx for turbines. Therefore, the Department considers this technology technically infeasible for the large simple cycle gas-fired turbines.

(g) XONON™
XONON™ is a catalytic technology developed by Catalytica Energy Systems, Inc. and now owned by Kawasaki. XONON™ uses flameless fuel combustion to lower NOx emissions. The combustion chamber of a gas turbine completely contains the XONON™ system. XONON™ completely combusts fuel to produce a high-temperature mixture typically about 2,400 °F. Dilution air is added to shape the temperature profile required at the turbine inlet. General Electric and Solar Turbines are testing this new catalyst technology, and the Department's research did not identify facilities using XONON™. The Department considers XONON™ a technically infeasible control technology for the large simple cycle gas-fired turbines because it is not commercially available.

Step 2 – Eliminate Technically Infeasible NOx Control Options for Compressor Turbines
As explained in Step 1, SNCR, NSCR, SCONOX™, and XONON™ are not feasible technologies to control NO_x emissions from simple cycle gas-fired turbines larger than 25 MW.

Step 3 – Rank Remaining NOx Control Options for Compressor Turbines
The following control technologies have been identified and ranked for control of NOx from the compressor turbines:

(a) SCR	(70% - 90% Control)
(b) DLN	(40% - 60% Control)
(c) Water/Steam Injection	(20% - 40% Control)

Step 4 – Evaluate the Most Effective Controls
SCR is the most effective NOx control for large simple cycle turbines. No unusual energy impacts were identified with the addition of SCR to the turbines. Environmental impacts include the disposal of the spent SCR catalyst when replacement becomes necessary, as well as ammonia slip from the SCR system. Neither the ammonia slip nor the waste disposal of the catalyst would preclude the use of SCR as a potential NOx control device.

RBLC Review
A review of similar units in the RBLC indicates that DLN is the principle NOx control technology, followed by SCR for large simple cycle gas-fired turbines.

Applicant Proposal

AGDC provided economic analyses using the 6th edition (2002) and 7th edition (2019) of the EPA Cost Control Manual (CCM) for installing SCR on the compressor turbines to demonstrate that it is not economically feasible on these units. AGDC noted that both economic analyses showed the costs for SCR installation to be economically infeasible, especially when using the 6th edition of the EPA CCM which considers more site-specific conditions, resulting in higher costs. Summaries of AGDC's analyses using the 6th and 7th editions of the CCM analyses are shown in Table 3-2 and Table 3-3 respectively.

Table 3-2: AGDC Economic Analysis (6th Edition) for Technically Feasible NOx Controls (EUs 1 – 6)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	37.4	242.8	$18,989,354	$4,410,481	$18,164
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

Table 3-3: AGDC Economic Analysis (7th Edition) for Technically Feasible NOx Controls (EUs 1 – 6)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	37.5	244.3	$11,582,176	$2,852,930	$11,677
Capital Recovery Factor = 0.0837 (5.5% interest rate for a 20 year equipment life)					

AGDC contends that the economic analyses indicate the level of NOx reduction from SCR does not justify the use of SCR for the large simple cycle gas-fired turbines based on the excessive cost per ton of NOx removed per year.

AGDC proposes the following as BACT for NOx emissions from the large simple cycle gas-fired turbines:

(a) NOx emissions from the operation of the large simple cycle gas-fired turbines will be controlled with the use of DLN combustors; and

(b) NOx emissions from the large simple cycle gas-fired turbines will not exceed 9 ppmv @ 15% O_2.

Department Evaluation of BACT for NOx Emissions from Large Simple Cycle Gas-Fired Turbines

The Department revised the cost analyses to reflect the current bank prime interest rate of 3.25% and revised the equipment life up to 25 years. The Department included the same assumption used by AGDC that DLN is an inherent design feature of new gas-fired combustion turbines and is therefore considered baseline for determining cost effectiveness. The Department did not modify the other assumptions used by AGDC in the cost analyses, including an 86.7% NOx control which reduced the NOx concentration from 15 ppmv to 2 ppmv, an unrestricted potential to emit of approximately 281 tpy, an aqueous ammonia cost of $2.24/gallon ($0.30/pound, Weekly Fertilizer Review, 4/2015), and the 0.16 $/kWh for electricity cost (average cost of electricity delivered to industrial customers in Alaska). Summaries of the Department's cost analyses using the 6th and 7th editions of the CCM analyses are shown in Table 3-4 and Table 3-5 respectively.

Table 3-4: Department Economic Analysis (6th Edition) for Technically Feasible NOx Controls (EUs 1 – 6)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	37.4	242.8	$18,989,354	$3,739,139	$15,399
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 3-5: Department Economic Analysis (7th Edition) for Technically Feasible NOx Controls (EUs 1 – 6)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	37.5	244.3	$11,582,176	$2,570,091	$10,519
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analyses using the 6th and 7th editions of the CCM indicates the level of NOx reduction does not justify the use of SCR as BACT for the large simple cycle gas-fired combustion turbines at the Liquefaction Plant.

Step 5 – Preliminary Selection of NOx BACT for Compressor Turbines

The Department's preliminary finding is that BACT for NOx emissions from the simple cycle gas-fired combustion turbines greater than 25 MW is as follows:

(a) NOx emissions from EUs 1 – 6 shall be controlled by operating and maintaining DLN combustors and good combustion practices at all times the units are in operation;

(b) NOx emissions from EUs 1 – 6 shall not exceed 9 ppmv @ 15% O_2 averaged over a 3-hour period; and

(c) Initial compliance with the proposed NOx emission limit will be demonstrated by submitting a vendor verification at least 60 prior to turbine startup and subsequently conducting a performance test to obtain an emission rate in accordance with 40 C.F.R. 60.8.

3.2 CO

Possible CO emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.110: large simple cycle natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 3-6.

Table 3-6: CO Control for Large Simple Cycle Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits (ppmv)
Oxidation Catalyst	10	1.5 – 10
Good Combustion & Clean Fuel	30	4 – 29
No Control	1	63

Step 1 – Identify CO Control Technologies for Compressor Turbines

From research, the Department identified the following technologies as available for CO control of large simple cycle natural gas-fired combustion turbines rated at greater than 25 MW:

(a) CO Oxidation Catalyst

Catalytic oxidation is a flue gas control that oxidizes CO and hydrocarbon compounds to carbon dioxide and water vapor in the presence of a noble metal catalyst; no reaction reagent is necessary. The reaction is spontaneous and no reactants are required. Catalytic oxidizers can provide oxidation efficiencies of up to 90% at temperatures between 750°F and 1,000°F; the efficiency of the oxidation temperature quickly deteriorates as the temperature decreases. The temperature of the turbine is expected to exhaust at approximately 1,000°F or less, remaining within the temperature range for CO oxidation catalysts. The Department considers oxidation catalysts a technically feasible control technology for large simple cycle gas-fired turbines.

(b) Good Combustion Practices (GCP) and Clean Fuel

GCP 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;
5. Proper fuel gas supply system designed to minimize effects of contaminants or fluctuations in pressure and flow on the fuel gas delivered.

Combustion efficiency is dependent on the gas residence time, the combustion temperature, and the amount of mixing in the combustion zone. GCP is accomplished primarily through combustion chamber design as it relates to residence time, combustion temperature, air-to-fuel mixing, and excess oxygen levels. In the Department’s search of the RBLC database, the majority of large simple cycle natural gas-fired combustion turbines used GCP and clean fuels as the primary control method for CO emissions. Therefore, the Department considers GCP and clean fuels a technically feasible control technology for large simple cycle gas-fired turbines.

(c) SCONOx™
As discussed in detail in the NOx BACT Section 3.1, SCONOx™ reduces CO emissions by oxidizing the CO to CO_2. This technology combines catalytic conversion of CO with an absorption and regeneration process without using ammonia reagent. SCONOx™ catalyst must operate in a temperature range of 300°F to 700°F, and therefore, turbine exhaust temperature must be reduced through the installation of a cooling system prior to entry to the SCONOx™ system. The Department's research did not identify facilities using SCONOX™ to control CO for turbines. Therefore, the Department considers this technology technically infeasible for the large simple cycle gas-fired turbines.

(d) Non-Selective Catalytic Reduction (NSCR)
NSCR uses a catalyst reaction to reduce CO to CO_2. The catalyst is usually a noble metal. The operating temperature for NSCR system ranges from about 700°F to 1,500°F, depending on the catalyst. NSCR requires a low excess oxygen concentration in the exhaust gas stream (typically less than 1%) to be effective because the oxygen must be depleted before the reduction chemistry can proceed. As such, NSCR is only effective with rich-burn gas-fired units that operate at all times with an air-to-fuel (A/F) ratio controller at or close to stoichiometric conditions. The Department's research did not identify NSCR as a control technology used to control CO emissions from turbines installed at any facility in the RBLC database. Therefore, the Department considers NSCR a technically infeasible control technology for the large simple cycle gas-fired turbines.

Step 2 – Eliminate Technically Infeasible CO Control Options for Compressor Turbines
As explained in Step 1, NSCR and SCONOX™ are not feasible technologies to control CO emissions from simple cycle gas-fired turbines larger than 25 MW.

Step 3 – Rank Remaining CO Control Options for Compressor Turbines
The following control technologies have been identified and ranked for control of CO from the compressor turbines:

(a)	Oxidation Catalyst	(90% Control)
(b)	GCP & Clean Fuels	(Less than 90%)

Step 4 – Evaluate the Most Effective Controls
An oxidation catalyst will reduce CO emissions from EUs 1 - 6 while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary. Turbine efficiency will be minimally impacted by the oxidation catalyst.

RBLC Review
A review of similar units in the RBLC indicates that an oxidation catalyst and good combustion practices are the principle CO control technologies used for simple cycle gas-fired turbines larger than 25 MW.

Applicant Proposal

AGDC proposed to install an oxidation catalyst and maintain good combustion practices for the compression turbine EUs 1 - 6 as BACT for reducing CO emissions. CO emissions from EUs 1 – 6 will not exceed 10 ppmv @ 15% O_2.

Department Evaluation of BACT for CO Emissions from Compressor Turbines
AGDC proposed to install oxidation catalyst with an emission rate of 10 ppmv @ 15% O_2, which would match the highest value found in the RBLC for CO emissions from large simple cycle turbines. This emission rate was set in a July 2010 permit for the Pueblo Airport Generating Station (RBLC ID No. CO-0073). The Department finds that a newly constructed simple cycle turbine with oxidation catalyst controls would be able to achieve a lower emission rate than what was proposed by AGDC. According to the Department's search of the RBLC going back ten years, the mean emission rate for large simple cycle turbines is 5.15 ppmv @ 15% O_2.

Step 5 – Preliminary Selection of CO BACT for Compressor Turbines
The Department's preliminary finding is that BACT for CO emissions from the simple cycle gas-fired combustion turbines greater than 25 MW is as follows:

(a) CO emissions from EUs 1 – 6 shall be controlled by operating and maintaining an oxidation catalyst and following good combustion practices at all times the units are in operation;

(b) CO emissions from EUs 1 – 6 shall not exceed 5 ppmv @ 15% O_2 averaged over a 3-hour period; and

(c) Initial compliance with the proposed CO emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

3.3 Particulates
Possible particulate emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.110: large simple cycle natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 3-7.

Table 3-7: Particulate Control for Large Simple Cycle Natural Gas Combustion Turbines

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Good Combustion & Clean Fuel	25	0.0033 – 0.013

Step 1 – Identify Particulate Control Technologies for Compressor Turbines
From research, the Department identified the following technologies as available for particulate control of large simple cycle natural gas-fired combustion turbines rated at greater than 25 MW:

(a) Fuel Specifications
Natural gas combustion turbines are among the cleanest fossil-fuel fired power generation equipment commercially available. Particulate emissions from combustion turbines fired with low sulfur natural gas are relatively insignificant and marginally significant using a liquid fuel. Particulate matter in the exhaust of liquid or gas-fired turbines are directly related to the levels of ash and metallic additives in fuel. As such,

fuel specifications are the primary method of particulate matter control and are a feasible control technology for the large simple cycle gas-fired turbines.

(b) Good Combustion Practices
As discussed in detail in the CO BACT Section 3.2, Proper management of the combustion process will result in a reduction of particulates. Therefore good combustion practices is a feasible control option for the large simple cycle gas-fired turbines.

Step 2 – Eliminate Technically Infeasible Particulate Control Options for Compressor Turbines
All control technologies identified are technically feasible for simple cycle gas-fired turbines larger than 25 MW.

Step 3 – Rank Remaining Particulate Control Options for Compressor Turbines
AGDC has accepted the only feasible control options. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
According to the RBLC clean fuels and good combustion practices are the applicable controls for particulates for EUs 1 – 6. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and clean fuels are the only particulate control technologies installed on simple cycle gas-fired turbines larger than 25 MW.

Applicant Proposal
AGDC proposed to use clean fuel and good combustion practices for the compressor turbines EUs 1 – 6 as BACT for reducing particulate emissions. Particulate emissions from EUs 1 – 6 will not exceed 0.0070 lb/MMBtu.

Step 5 – Preliminary Selection of Particulate BACT for Compressor Turbines
The Department's preliminary finding is that BACT for particulate emissions from the simple cycle gas-fired combustion turbines greater than 25 MW is as follows:

(a) Particulate emissions from EUs 1 – 6 shall be minimized by maintaining good combustion practices and burning clean fuels at all times the units are in operation;

(b) Particulate emissions from EUs 1 – 6 shall not exceed 0.0070 lb/MMBtu averaged over a 3-hour period (AP-42 Table 3.1-2a, particulate (total) emissions rate for gas-fired turbines); and

(c) Initial compliance with the proposed particulate emission limit will be demonstrated by conducting a performance test to obtain an emission rate, or supplying the Department with a vendor verification that the EUs will comply with the BACT limit.

3.4 SO_2

Possible SO_2 emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.110: large simple cycle natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 3-8.

Table 3-8: SO_2 Control for Large Simple Cycle Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits[11](Sulfur in Fuel)
Good Combustion & Clean Fuel	8	1 – 2 gr/100 dscf 16.9 – 33.8 ppmv
No Control	2	1 – 2 gr/100 dscf 16.9 – 33.8 ppmv

Step 1 – Identify SO_2 Control Technologies for Compressor Turbines

From research, the Department identified the following technologies as available for SO_2 control of large simple cycle natural gas-fired combustion turbines rated at greater than 25 MW:

(a) Good Combustion Practices (GCP) and Clean Fuels
As discussed in detail in CO BACT Section 3.2, as well as the fuel specifications portion of particulate BACT Section 3.3, GCP and clean fuels is a common technique for controlling SO_2 emissions. SO_2 emissions in the exhaust of liquid or gas-fired turbines are directly related to the levels of sulfur in fuel. As such, fuel specifications are the primary method of SO_2 emissions control and are a feasible control technology for the combustion turbines.

Step 2 – Eliminate Technically Infeasible SO_2 Control Options for Compressor Turbines

All control technologies identified are technically feasible for simple cycle gas-fired turbines larger than 25 MW.

Step 3 – Rank Remaining SO_2 Control Options for Compressor Turbines

AGDC has accepted the only feasible control options. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls

According to the RBLC clean fuels and good combustion practices are the applicable controls for SO_2 emissions for EUs 1 – 6. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review

A review of similar units in the RBLC indicates that good combustion practices and clean fuels are the only SO_2 emission control technologies installed on simple cycle gas-fired turbines larger than 25 MW.

Applicant Proposal

[11] The RBLC listed the emission limits in grains per 100 dry standard cubic feet (gr/100 dscf), which the Department converted to ppmv sulfur using Galvanic Applied Sciences Inc.'s Sulfur Measurement Handbook stating 1 gr/dscf = 16.92 ppmv sulfur at standard temperature and pressure.

AGDC proposed to use clean fuels and good combustion practices for the compressor turbines EUs 1 – 6 as BACT for reducing SO_2 emissions. AGDC will utilize only pipeline quality natural gas in the combustion turbines EUs 1 – 6 with a total sulfur content not to exceed 16 ppmv (1 grain/100 dscf).

Step 5 – Preliminary Selection of SO_2 BACT for Compressor Turbines
The Department's preliminary finding is that BACT for SO_2 emissions from the simple cycle gas-fired combustion turbines greater than 25 MW is as follows:

(a) SO_2 emissions from EUs 1 – 6 shall be minimized by maintaining good combustion practices and burning pipeline quality natural gas with a total sulfur content not to exceed 16 ppmv at all times the units are in operation; and

(b) Compliance with the proposed fuel sulfur content limit will be demonstrated with fuel shipment receipts and/or fuel test results for total sulfur content.

3.5 VOC
Possible VOC emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.110: large simple cycle natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 3-9.

Table 3-9: VOC Control for Large Simple Cycle Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits
Good Combustion & Clean Fuel	10	1.4 – 5 ppmv 0.0018 – 0.014 lb/MMBtu
Oxidation Catalyst	7	2 – 3 ppmv

Step 1 – Identify VOC Control Technologies for Compressor Turbines
From research, the Department identified the following technologies as available for VOC control of large simple cycle natural gas-fired combustion turbines rated at greater than 25 MW:

(a) Oxidation Catalyst
Oxidation catalyst can control VOC emissions in the exhaust gas with the proper selection of catalyst. The oxidation reaction is spontaneous and does not require addition reagents. Formaldehyde and other organic HAPs can see reductions of 85% to 90%. The Department considers oxidation catalysts a technically feasible control technology for large simple cycle gas-fired turbines.

(b) Good Combustion Practices
VOC emissions in gas combustion turbines result from incomplete combustion. These VOCs can contain a wide variety of organic compounds, some of which are hazardous air pollutants. VOCs are discharged into the atmosphere when some of the fuel is un-combusted or only partially combusted. VOCs can be trace constituents of the fuel or products of pyrolysis of heavier hydrocarbons in the gas. In that complete combustion will reduce VOC emissions, good combustion practices are a feasible control method for large simple cycle gas-fired turbines.

Step 2 – Eliminate Technically Infeasible VOC Control Options for Compressor Turbines
All control technologies identified are technically feasible for simple cycle gas-fired turbines larger than 25 MW.

Step 3 – Rank Remaining VOC Control Options for Compressor Turbines
The following control technologies have been identified and ranked for control of VOC from the compressor turbines:

(a) Oxidation Catalyst (85% to 90% Control)
(b) Good Combustion Practices (Less than 85% Control)

Step 4 – Evaluate the Most Effective Controls
An oxidation catalyst will reduce VOC emissions from EUs 1 - 6 while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary. Turbine efficiency will be minimally impacted by the oxidation catalyst.

RBLC Review
A review of similar units in the RBLC indicates that an oxidation catalyst and good combustion practices are the principle VOC control technologies used on simple cycle gas-fired turbines larger than 25 MW.

Applicant Proposal
AGDC proposed to install an oxidation catalyst and use good combustion practices for the compressor turbines EUs 1 – 6 as BACT for reducing VOC emissions. VOC emissions from EUs 1 – 6 will not exceed 0.0022 lb/MMBtu.

Step 5 – Preliminary Selection of VOC BACT for Compressor Turbines
The Department's preliminary finding is that BACT for VOC emissions from the simple cycle gas-fired combustion turbines greater than 25 MW is as follows:

(a) VOC emissions from EUs 1 – 6 shall be controlled by operating and maintaining an oxidation catalyst and good combustion practices at all times the units are in operation;
(b) VOC emissions from EUs 1 – 6 shall not exceed 0.0022 lb/MMBtu averaged over a 3-hour period (AP-42 VOC emission rate for gas-fired turbines); and
(c) Initial compliance with the proposed VOC emission limit will be demonstrated by conducting a performance test to obtain an emission rate, or supplying the Department with a vendor verification that the EUs will comply with the BACT limit.

3.6 GHG
Possible GHG emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.110: large simple cycle natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 3-10.

Table 3-10: GHG Control for Large Simple Cycle Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits
Good Combustion & Clean Fuel	11	884 – 1,707 lb/MWh 117.0 – 120.0 lb/MMBtu
Carbon Capture and Sequestration (CCS)	0	N/A
No Control	10	1030 – 1,461 lb/MWh

CO_2 and N_2O emissions are produced during natural gas combustion in gas turbines. Nearly all of the fuel carbon is converted to CO_2 during the combustion process, regardless of the firing configuration. CH_4 is also present in the exhaust gas and is thought to be unburned fuel in the case of natural gas.

Step 1 – Identify GHG Control Technologies for Compressor Turbines
From research, the Department identified the following technologies as available for GHG control of large simple cycle natural gas-fired combustion turbines rated at greater than 25 MW:

(a) Thermal Efficiency and the Utilization of Thermal Energy and Electricity
The EPA Guidance states that options that improve the overall efficiency of the source or modification must be evaluated in the BACT analysis. These options can include technologies, processes, and practices at the emitting unit that allows the plant to operate more efficiently. In general, an efficient process requires less fuel for process heat, and therefore reduces the amount of CO_2 produced. In addition to energy efficiency of the individual emitting units, process improvements that impact the facility's higher-energy-using equipment, processes or operations could lead to reductions in emissions. There are a number of cycle configurations of a turbine as well as turbine designs that improves the efficiency of the operation.

1. Simple Cycle Gas-Fired Turbine (Baseline)
In the baseline case, each turbine would operate in a simple cycle, which includes a single gas turbine to generate power. This configuration uses air as a diluent to reduce combustion flame temperatures. Fuel and air are pre-mixed in an initial stage resulting in a uniform, lean, unburned fuel/air mixture, which is then delivered to the combustor. The efficient combustion resulting from the process reduces the fuel consumption and CO_2 emissions.

2. Turbine with Waste Heat Recovery (Combined Cycle or Combined Heat and Power)
In a combined cycle turbine, waste heat recovery units are added to the exhausts of the turbines, and recover previously unused energy to drive a steam turbine generator (STG). In a Combined Heat and Power (also known as cogeneration) turbine, waste heat from the turbine exhaust is put to a productive use such as heating a building, or used for a process that requires heat inputs. Utilizing waste heat in turbines leads to a more energy efficient operation because the additional power produced by the STG and heat produced by the turbine does not require additional fuel consumption. Besides the STG, this configuration requires additional equipment such as condensers, deaerator, and boiler feed pump, which increases the footprint and the cost of the facility. Furthermore, the additional steam turbine generation in a fixed

electrical demand application forces gas turbine load reductions, increasing the gas turbine heat rates, and offsetting CO_2 reduction benefits.

3. Aeroderivative Turbine
Aeroderivative turbines are similar to industrial turbines (also known as heavy duty or frame turbines) except their design is derived from aviation turbines, causing them to be lighter and generally smaller. Aeroderivative turbines have been used in gas compression and electrical power generation operations due to their ability to be shut down and handle load changes quickly. These turbines are also used in the marine industry due to their reduced weight. In addition to being lighter weight than traditional industrial turbines, these turbines are generally more efficient than industrial turbines of comparable size and capacity. This leads to less fuel consumption to achieve the same power output, resulting in a reduction of GHG emissions in the 4% to 12% range.

4. Organic Rankine Cycle (ORC)
ORC uses a refrigerant working fluid that is heated by engine exhaust gas from the natural gas fired turbines, and expands through a turbine connected to the engine shaft. The ORC system involves the same components as in a conventional steam power plant; however, instead of using water as a working fluid, ORC uses a refrigerant with a boiling point lower than that of water, and enables recovery of heat from lower-temperature heat sources. The ORC offers reduced equipment size compared to the steam cycle. This equipment is at their best in air-cooled applications where the heat source is below approximately 400ºF. The heat source for this application is the gas turbine exhaust, and is approximately 800 to 1,000 ºF, which would require an additional thermal fluid loop.

   A disadvantage of the ORC is that, the configuration requires more fuel consumption compared to the steam cycle, and operation when ambient temperature is below 40ºF (approximately 50% of the year) makes the system less efficient. Also, additional heat exchangers may be needed to preheat the ORC working fluid and the combustion air, which would increase the cost and complexity of the system. The Department does not consider ORC as a technically feasible technology for control of GHGs.

(b) Carbon Capture and Sequestration (CCS)
The EPA Guidance classifies CCS as "an add-on pollution control technology that is 'available' for facilities emitting CO_2 in large amounts." AGDC has included a description of CCS, and a review of the technology in their permit application.

CCS is a broad term that includes a number of technologies that involves three general steps: 1) capturing the carbon dioxide directly at its source and compressing it, 2) transporting, and 3) storing it in non-atmospheric reservoirs. Capture, the most energy-intensive of all the processes, can be done either through pre-combustion methods or post-combustion methods. Pre-combustion requires the use of oxygen instead of air to combust the fuel. In general, pre-combustion reduces the energy required and the cost to remove CO_2 emissions from the combustion process. The concentration of CO_2 in the untreated gas stream is higher in pre-combustion capture, thereby requiring less and cheaper equipment. The other method is post-combustion, applied to conventional combustion techniques using air and carbon-containing fuels in order to isolate CO_2 from the combustion exhaust gases.

After capture, the CO_2 is compressed to a near-liquid state, and transported via pipeline to a designated storage area. These reservoirs are deep enough for the pressure of the earth to keep it in a liquidized form where it will be sequestered for thousands of years. Depleted oil and gas reservoirs are the most practical places for storing CO_2 emissions that would otherwise be emitted back into the atmosphere. Other options for storage include deep saline formations, un-mineable coal seams, and even offshore storage. The stored CO_2 is expected to remain underground for as long as thousands, even millions of years.

The Department's research did not identify CCS as a control technology used to control GHG emissions from turbines installed at any facility in the RBLC database. However, AGDC submitted an economic analysis for CCS on the gas-fired turbines that will be advanced to the next step and evaluated.

(c) Good Combustion Practices (GCP) and Clean Fuels
Discussed in detail in CO BACT Section 3.2, as well as the fuel specifications portion of particulate BACT Section 3.3. GCP and clean fuels is a common technique for controlling GHG emissions. GHG emissions in the exhaust of liquid or gas-fired turbines are directly related to the carbon content in the fuel. Natural gas has the lowest amount of GHG emissions per Btu of energy of any fossil fuel, and is considered a feasible control technology for the compressor turbines.

Step 2 – Eliminate Technically Infeasible GHG Control Options for Compressor Turbines
As explained in Step 1, ORC is not a feasible technology to control GHG emissions from simple cycle gas-fired turbines larger than 25 MW.

Turbine with Waste Heat Recovery (Combined Cycle or Combined Heat and Power): the facility is currently designed to use six simple cycle turbines as the mechanical drivers for the refrigeration process of the natural gas, and will be using separate combined cycle turbines for the power generation aspect of the LNG Plant. Combined heat and power from the compressor turbines will not be useful for the LNG Plant as the proposed facility will already be supplied with gas treated at the Gas Treatment Plant, greatly reducing the need for heat within the facility. Requiring the compressor turbines to include a waste heat recovery system would fundamentally redefine the nature of the proposed stationary source, and is therefore not considered as an option in the BACT analysis.

Aeroderivative turbine: the facility is currently designed to use six simple cycle turbines as the mechanical drivers for the refrigeration process of the natural gas. Requiring the compressor turbines to be aeroderivative models would fundamentally redefine the project, and is therefore not considered as an option in the BACT analysis.

Step 3 – Rank Remaining GHG Control Options for Compressor Turbines
The following control technologies have been identified and ranked for control of GHG from the compressor turbines:

(a) CCS (80% - 90% Control)
(b) GCP and Clean Fuels (<80% Control)

Step 4 – Evaluate the Most Effective Controls
According to the RBLC, clean fuels and good combustion practices are the applicable controls for GHG emissions for EUs 1 – 6. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and clean fuels are the only GHG emission control technologies currently installed on simple cycle gas-fired turbines larger than 25 MW.

Applicant Proposal
AGDC provided an economic analysis of the top most effective control technology CCS for a combination of the simple cycle compressor turbines EUs 1 – 6 and the combined cycle power generation turbines EUs 7 – 10 to demonstrate that the use of the most effective control (CCS) is not economically feasible. The economic analysis included cost data from a study conducted by URS Corporation for AGDC's Gas Treatment Plant in 2010 titled, "Alaska Pipeline Project Gas Treatment Plant: CO_2 Capture Study" as well as cost data from the Golden Pass LNG Project PSD Permit Application. AGDC noted that the cost for CCS alone for the turbines at the Liquefaction Plant would be more than 5 billion dollars. AGDC calculated that a 90% control of emissions would avoid 3.8 million tons of CO_2 per year at the cost of more than $165/ton. A summary of AGDC's analysis is shown in Table 3-11.

Table 3-11: AGDC Economic Analysis for Technically Feasible GHG Controls (EUs 1 – 10)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
CCS	419,970	3,779,734	$5,018,084,403	$623,269,718	$165
Capital Recovery Factor = 0.0858 (7.00% interest rate for a 25 year equipment life)					

AGDC proposed to use clean fuels (pipeline quality natural gas) and good combustion practices for the compressor turbines EUs 1 – 6 as BACT for reducing GHG emissions. GHG emissions from EUs 1 – 6 will not exceed 117.1 lb/MMBtu, which is the CO_2 equivalent (CO_2e) emissions rates for burning natural gas in 40 CFR Part 98: Mandatory Greenhouse Gas Reporting. The total CO_2e emissions rate is calculated with the equation $CO_2(1) + CH_4(25) + N_2O(298)$.

Department Evaluation of BACT for GHG Emissions from Gas-Fired Turbines
The Department used the lower capital investment cost from the CO_2 Capture Study for the Gas Treatment Plant of $3.6 billion to create an economic analysis. The Department's economic

analysis used the current bank prime interest rate of 3.25%, an equipment life of 25 years, and assumed a 90% control of CO_2 emissions. A summary of the Department's cost analysis for all turbines EUs 1-10 combined is shown in Table 3-12.

Table 3-12: Department Economic Analysis for Technically Feasible GHG Controls (EUs 1 – 10)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
CCS	421,287.0	3,791,583.4	$3,631,800,000	$534,314,775	$140.9
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analysis, combined with the fact that there are no examples of CCS being used to control GHG emissions from any facility in the RBLC, indicates the level of GHG reduction does not justify the use of CCS as BACT for the turbines at the Liquefaction Plant.

Step 5 – Preliminary Selection of GHG BACT for Compressor Turbines
The Department's preliminary finding is that BACT for GHG emissions from the simple cycle gas-fired combustion turbines greater than 25 MW is as follows:

(a) GHG emissions from EUs 1 – 6 shall be minimized by maintaining good combustion practices and burning clean fuels at all times the units are in operation; and

(b) GHG emissions from EUs 1 – 6 shall not exceed 117.1 lb/MMBtu averaged over a 3-hour period.

4.0 POWER GENERATION TURBINES

The Liquefaction Plant will use four combined cycle natural gas-fired turbines (EUs 7 – 10), make and model yet to be selected) to supply power for the facility. Each turbine is planned to have a nominal capacity of approximately 384 MMBtu/hr, for a total of 1,536 MMBtu/hr. The power generation turbines will emit CO, NOx, SO_2, particulates, VOC, and GHG. The following sections provide the BACT review for each of these pollutants.

4.1 NOx

Possible NOx emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.210: large combined cycle and cogeneration natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 4-1.

Table 4-1: NOx Controls for Large Combined Cycle Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits (ppmv)
Selective Catalytic Reduction	67	2 – 9
Dry DLN Low NOx Combustors	3	5 – 25

Step 1 – Identify NOx Control Technologies for Power Generation Turbines

From research, the Department identified the following technologies as available for control of NOx emissions from gas-fired combined cycle combustion turbines rated at 25 MW or greater:

(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. The operating temperature of conventional SCR systems ranges from 400 degrees Fahrenheit (°F) to 800°F. High temperature SCR relies on special material reaction grids and can operate at higher temperature ranges between 700°F to 1,075°F. High temperature SCR is most frequently installed on simple cycle turbines. Depending on the overall NH_3-to-NOx ratio, removal efficiencies are generally 80 to 90 percent. In the Department's search of the RBLC database, the majority of large combined cycle natural gas-fired combustion turbines used SCR as the primary control method for NOx emissions and contained a BACT limit of 2 ppmv. Hence, the Department considers SCR a technically feasible control technology for large combined cycle gas-fired turbines.

(b) Dry Low NOx (DLN)

DLN combustors (marketed under many similar names such as SoLoNOx or DLE) utilize multistage premix combustors where the air and fuel is mixed at a lean (high oxygen) fuel-to-air ratio. The excess air in the lean mixture acts as a heat sink, which lowers peak combustion temperatures and also ensures a more homogeneous mixture avoiding localized "hot spots", both resulting in greatly reduced NOx formation rates. DLN combustors have the potential to reduce NOx emissions by 40 to 60%. Note that 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 considers DLN a technically feasible control technology for large combined cycle gas-fired turbines.

(c) Water/Steam Injection (ULSD)

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, incurring additional costs. Water/steam injection also increases CO emissions as it lowers the combustion temperature. Depending on baseline uncontrolled NOx levels, water or steam injection can reduce NOx by 60% or more. Generally speaking the Department considers water/steam injection a technically feasible control technology for large combined cycle gas-fired turbines. However, the base model turbine selected by ADGC already comes equipped with DLN technology which is not compatible with water/steam injection, and has lower NOx emission rates than water/steam injection. Additionally, the Department's research did not identify water/steam injection as a technology used to control NOx emissions from large combined cycle turbines installed at any facility in the RBLC database. Hence the Department considers water/steam injection as a technically infeasible control technology for the large combined cycle gas-fired turbines.

(d) 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 combined cycle turbines exhaust gas normally ranges from 800°F to 1,000°F, achieving the required reaction temperature is the main difficulty for application of SNCR to turbines. The Department's research did not identify SNCR as a technology used to control NOx emissions from turbines installed at any facility. Hence the Department considers SNCR as a technically infeasible control technology for the large combined cycle gas-fired turbines.

(e) 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. 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. Turbines 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 turbines installed at any facility. Hence the Department considers NSCR as a technically infeasible control technology for the large combined cycle gas-fired turbines.

(f) SCONOX™
SCONOX™ is a new catalytic absorption technology developed by Goal Line Environmental Technologies, Inc. to treat exhaust gas with a potassium carbonate coated catalyst, reducing NOx to N_2. The catalyst also oxidizes CO to CO_2, and NO and NO_2 to potassium nitrates (KNO_3). The catalyst is regenerated by passing dilute H_2 over it which converts the KNO_2 and KNO_3 to K_2CO_3, water, and N_2. One disadvantage of SCONOX™ is that the catalyst is very sensitive to sulfur in the fuel. For fuel gas sulfur content exceeding 30 ppmv, a sulfur adsorption catalyst must be installed upstream of the

SCONOX™ catalyst to remove sulfur. No known installations exist in low ambient temperature settings or on turbine arrangements in industrial settings. The Department's research did not identify facilities using SCONOX™ to control NOx for turbines. Therefore, the Department considers this technology technically infeasible for the large combined cycle gas-fired turbines.

(g) XONON™
XONON™ is a catalytic technology developed by Catalytica Energy Systems, Inc. and now owned by Kawasaki. XONON™ uses flameless fuel combustion to lower NOx emissions. The combustion chamber of a gas turbine completely contains the XONON™ system. XONON™ completely combusts fuel to produce a high-temperature mixture typically about 2,400 °F. Dilution air is added to shape the temperature profile required at the turbine inlet. General Electric and Solar Turbines are testing this new catalyst technology, and the Department's research did not identify facilities using XONON™. The Department considers XONON™ a technically infeasible control technology for the large combined cycle gas-fired turbines because it is not commercially available.

Step 2 – Eliminate Technically Infeasible NOx Control Options for Power Generation Turbines
As explained in Step 1, water/steam injection, SNCR, NSCR, SCONOX™, and XONON™ are not feasible technologies to control NO_x emissions from the combined cycle gas-fired turbines larger than 25 MW.

Step 3 – Rank Remaining NOx Control Options for Power Generation Turbines
The following control technologies have been identified and ranked for control of NOx from the power generation turbines:

(a) SCR (70% - 90% Control)
(b) DLN (40% - 60% Control)

Step 4 – Evaluate the Most Effective Controls
SCR is the most effective NOx control for large combined cycle turbines. No unusual energy impacts were identified with the addition of SCR to the turbines. Environmental impacts include the disposal of the spent SCR catalyst when replacement becomes necessary, as well as ammonia slip from the SCR system. Neither the ammonia slip nor the waste disposal of the catalyst would preclude the use of SCR as a potential NOx control device.

RBLC Review
A review of similar units in the RBLC indicates that SCR is the principle NOx control technology, followed by DLN combustors for large combined cycle gas-fired turbines.

Applicant Proposal
AGDC provided economic analyses using the 6th edition (2002) and 7th edition (2019) of the EPA Cost Control Manual (CCM) for installing SCR on the power generation turbines to demonstrate that it is not economically feasible on these units. AGDC noted that both economic analyses showed the costs for SCR installation to be economically infeasible, especially when using the 6th edition of the EPA CCM which considers more site-specific conditions, resulting in

higher costs. Summaries of AGDC's analyses using the 6th and 7th editions of the CCM analyses are shown in Table 4-2 and Table 4-3 respectively.

Table 4-2: AGDC Economic Analysis (6th Edition) for Technically Feasible NOx Controls (EUs 7 – 10)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	13.8	89.7	$10,004,899	$2,205,510	$24,588
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

Table 4-3: AGDC Economic Analysis (7th Edition) for Technically Feasible NOx Controls (EUs 7 – 10)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	13.8	90.3	$6,062,828	$1,040,007	$11,522
Capital Recovery Factor = 0.0837 (5.5% interest rate for a 20 year equipment life)					

AGDC contends that the economic analyses indicate the level of NOx reduction from SCR does not justify the use of SCR for the large combined cycle gas-fired turbines based on the excessive cost per ton of NOx removed per year.

AGDC proposes the following as BACT for NOx emissions from the large combined cycle gas-fired turbines:

(a) NOx emissions from the operation of the large combined cycle gas-fired turbines will be controlled with the use of DLN combustors; and

(b) NOx emissions from the large combined cycle gas-fired turbines will not exceed 9 ppmv @ 15% O_2.

Department Evaluation of BACT for NOx Emissions from Large Combined Cycle Gas-Fired Turbines

The Department revised the cost analyses to reflect the current bank prime interest rate of 3.25% and revised the equipment life up to 25 years. The Department included the same assumption used by AGDC that DLN is an inherent design feature of new gas-fired combustion turbines and is therefore considered baseline for determining cost effectiveness. The Department did not modify the other assumptions used by AGDC in the cost analyses, including an 86.7% NOx control which reduced the NOx concentration from 15 ppmv to 2 ppmv, an unrestricted potential to emit of approximately 104 tpy, an aqueous ammonia cost of $2.24/gallon ($0.30/pound, Weekly Fertilizer Review, 4/2015), and the 0.16 $/kWh for electricity cost (average cost of electricity delivered to industrial customers in Alaska). Summaries of the Department's cost analyses using the 6th and 7th editions of the CCM analyses are shown in Table 4-4 and Table 4-5 respectively.

Table 4-4: Department Economic Analysis (6th Edition) for Technically Feasible NOx Controls (EUs 7 – 10)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	13.8	89.7	$10,004,899	$1,851,801	$20,645
Capital Recovery Factor =0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 4-5: Department Economic Analysis (7th Edition) for Technically Feasible NOx Controls (EUs 7 – 10)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	13.8	90.3	$6,062,828	$891,555	$9,878
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analyses using the 6th and 7th editions of the CCM indicates the level of NOx reduction does not justify the use of SCR as BACT for the large combined cycle gas-fired combustion turbines at the Liquefaction Plant.

Step 5 – Preliminary Selection of NOx BACT for Power Generation Turbines
The Department's preliminary finding is that BACT for NOx emissions from the combined cycle gas-fired combustion turbines greater than 25 MW is as follows:

(a) NOx emissions from EUs 7 – 10 shall be controlled by operating and maintaining DLN combustors at all times the units are in operation;

(b) NOx emissions from EUs 7 – 10 shall not exceed 9ppmv @ 15% O_2 averaged over a 3-hour period; and

(c) Initial compliance with the proposed NOx emission limit will be demonstrated by submitting a vendor verification at least 60 prior to turbine startup and subsequently conducting a performance test to obtain an emission rate in accordance with 40 C.F.R. 60.8.

4.2 CO

Possible CO emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.210: large combined cycle and cogeneration natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 4-6.

Table 4-6: CO Control for Large Combined Cycle Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits (ppmv)

Oxidation Catalyst	78	0.9 – 15
Good Combustion & Clean Fuel	17	2 – 50

Step 1 – Identify CO Control Technologies for Power Generation Turbines
From research, the Department identified the following technologies as available for CO control of large combined cycle natural gas-fired combustion turbines rated at greater than 25 MW:

(a) CO Oxidation Catalyst
Catalytic oxidation is a flue gas control that oxidizes CO and hydrocarbon compounds to carbon dioxide and water vapor in the presence of a noble metal catalyst; no reaction reagent is necessary. The reaction is spontaneous and no reactants are required. Catalytic oxidizers can provide oxidation efficiencies of up to 90% at temperatures between 750°F and 1,000°F; the efficiency of the oxidation temperature quickly deteriorates as the temperature decreases. The temperature of the turbine is expected to exhaust at approximately 1,000°F or less, remaining within the temperature range for CO oxidation catalysts. In the Department's search of the RBLC database, the majority of large combined cycle natural gas-fired combustion turbines used an oxidation catalyst as the primary control method for CO emissions and contained a BACT limit between 1.5 - 3 ppmv. Therefore, the Department considers oxidation catalysts a technically feasible control technology for large combined cycle gas-fired turbines.

(b) Good Combustion Practices (GCP) and Clean Fuel
GCP 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;
5. Proper fuel gas supply system designed to minimize effects of contaminants or fluctuations in pressure and flow on the fuel gas delivered.

Combustion efficiency is dependent on the gas residence time, the combustion temperature, and the amount of mixing in the combustion zone. GCP is 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 GCP and clean fuels a technically feasible control technology for large combined cycle gas-fired turbines.

(c) SCONOx™
As discussed in detail in the NOx BACT Section 4.1, SCONOx™ reduces CO emissions by oxidizing the CO to CO_2. This technology combines catalytic conversion of CO with an absorption and regeneration process without using ammonia reagent. SCONOx™ catalyst must operate in a temperature range of 300°F to 700°F, and therefore, turbine exhaust temperature must be reduced through the installation of a cooling system prior to entry to the SCONOx™ system. The Department's research did not identify facilities

using SCONOX™ to control CO for turbines. Therefore, the Department considers this technology technically infeasible for the large combined cycle gas-fired turbines.

(d) Non-Selective Catalytic Reduction (NSCR)
NSCR uses a catalyst reaction to reduce CO to CO_2. The catalyst is usually a noble metal. The operating temperature for NSCR system ranges from about 700°F to 1,500°F, depending on the catalyst. NSCR requires a low excess oxygen concentration in the exhaust gas stream (typically less than 1%) to be effective because the oxygen must be depleted before the reduction chemistry can proceed. As such, NSCR is only effective with rich-burn gas-fired units that operate at all times with an air-to-fuel (A/F) ratio controller at or close to stoichiometric conditions. The Department's research did not identify NSCR as a control technology used to control CO emissions from turbines installed at any facility in the RBLC database. Therefore, the Department considers NSCR a technically infeasible control technology for the large combined cycle gas-fired turbines.

Step 2 – Eliminate Technically Infeasible CO Control Options for Power Generation Turbines
As explained in Step 1, NSCR and SCONOX™ are not feasible technologies to control CO emissions from combined cycle gas-fired turbines larger than 25 MW.

Step 3 – Rank Remaining CO Control Options for Power Generation Turbines
The following control technologies have been identified and ranked for control of CO from the power generation turbines:

(a) Oxidation Catalyst	(90% Control)
(b) GCP & Clean Fuels	(Less than 90% Control)

Step 4 – Evaluate the Most Effective Controls
An oxidation catalyst will reduce CO emissions from EUs 7 - 10 while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary. Turbine efficiency will be minimally impacted by the oxidation catalyst.

RBLC Review
A review of similar units in the RBLC indicates that an oxidation catalyst and good combustion practices are the principle CO control technologies used for combined cycle gas-fired turbines larger than 25 MW.

Applicant Proposal
AGDC proposed to install an oxidation catalyst and maintain good combustion practices for the power generation turbine EUs 7 - 10 as BACT for reducing CO emissions. CO emissions from EUs 7 – 10 will not exceed 10 ppmv @ 15% O_2.

Department Evaluation of BACT for CO Emissions from Compressor Turbines
AGDC proposed to install oxidation catalyst with an emission rate of 10 ppmv @ 15% O_2, which would be one of the highest values in the RBLC for CO emissions from large combined cycle turbines. The Department finds that a newly constructed combined cycle turbine with oxidation

catalyst controls would be able to achieve a lower emission rate than what was proposed by AGDC. According to the Department's search of the RBLC going back ten years, the mean emission rate for large combined cycle turbines is 2.6 ppmv @ 15% O_2.

Step 5 – Preliminary Selection of CO BACT for Power Generation Turbines
The Department's preliminary finding is that BACT for CO emissions from the combined cycle gas-fired combustion turbines greater than 25 MW is as follows:

(a) CO emissions from EUs 7 – 10 shall be controlled by operating and maintaining an oxidation catalyst at all times the units are in operation;

(b) CO emissions from EUs 7 – 10 shall not exceed 5 ppmv @ 15% O_2 averaged over a 3-hour period; and

(c) Initial compliance with the proposed CO emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

4.3 Particulates

Possible particulate emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.210: large combined cycle and cogeneration natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 4-7.

Table 4-7: Particulate Control for Large Combined Cycle Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Good Combustion & Clean Fuel	70	0.0025 – 0.044

Step 1 – Identify Particulate Control Technologies for Power Generation Turbines
From research, the Department identified the following technologies as available for particulate control of large combined cycle natural gas-fired combustion turbines rated at greater than 25 MW:

(a) Fuel Specifications
Natural gas combustion turbines are among the cleanest fossil-fuel fired power generation equipment commercially available. Particulate emissions from combustion turbines fired with low sulfur natural gas are relatively insignificant and marginally significant using a liquid fuel. Particulate matter in the exhaust of liquid or gas-fired turbines are directly related to the levels of ash and metallic additives in fuel. As such, fuel specifications are the primary method of particulate matter control and are a feasible control technology for the large combined cycle gas-fired turbines.

(b) Good Combustion Practices
As discussed in detail in the CO BACT Section 3.2, proper management of the combustion process will result in a reduction of particulates. Therefore good combustion practices is a feasible control option for the large combined cycle gas-fired turbines.

Step 2 – Eliminate Technically Infeasible Particulate Control Options for Power Generation Turbines
All control technologies identified are technically feasible for combined cycle gas-fired turbines larger than 25 MW.

Step 3 – Rank Remaining Particulate Control Options for Power Generation Turbines
AGDC has accepted the only feasible control options. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
According to the RBLC clean fuels and good combustion practices are the applicable controls for particulates for EUs 7 – 10. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and clean fuels are the only particulate control technologies installed on combined cycle gas-fired turbines larger than 25 MW.

Applicant Proposal
AGDC proposed to use clean fuel and good combustion practices for the power generation turbines EUs 7 – 10 as BACT for reducing particulate emissions. Particulate emissions from EUs 7 – 10 will not exceed 0.0070 lb/MMBtu.

Step 5 – Preliminary Selection of Particulate BACT for Power Generation Turbines
The Department's preliminary finding is that BACT for particulate emissions from the combined cycle gas-fired combustion turbines greater than 25 MW is as follows:

(a) Particulate emissions from EUs 7 – 10 shall be minimized by maintaining good combustion practices and burning clean fuels at all times the units are in operation;

(b) Particulate emissions from EUs 7 – 10 shall not exceed 0.0070 lb/MMBtu averaged over a 3-hour period (AP-42 particulate (total) emissions rate for gas-fired turbines); and

(c) Initial compliance with the proposed particulate emission limit will be demonstrated by conducting a performance test to obtain an emission rate, or supplying the Department with a vendor verification that the EUs will comply with the BACT limit.

4.4 SO_2
Possible SO_2 emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.210: large combined cycle and cogeneration natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 4-8.

Table 4-8: SO_2 Control for Large Combined Cycle Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits[11] (Sulfur in Fuel)
Good Combustion & Clean Fuel	10	0.75 – 5 gr/100 dscf 12.7 – 84.6 ppmv
No Control	1	2 gr/100 dscf

		33.8 ppmv

Step 1 – Identify SO_2 Control Technologies for Power Generation Turbines
From research, the Department identified the following technologies as available for SO_2 control of large combined cycle natural gas-fired combustion turbines rated at greater than 25 MW:

(a) Good Combustion Practices (GCP) and Clean Fuels
As discussed in detail in CO BACT Section 3.2, as well as the fuel specifications portion of particulate BACT Section 3.3, GCP and clean fuels is a common technique for controlling SO_2 emissions. SO_2 emissions in the exhaust of liquid or gas-fired turbines are directly related to the levels of sulfur in fuel. As such, fuel specifications are the primary method of SO_2 emissions control and are a feasible control technology for the combustion turbines.

Step 2 – Eliminate Technically Infeasible SO_2 Control Options for Power Generation Turbines
All control technologies identified are technically feasible for combined cycle gas-fired turbines larger than 25 MW.

Step 3 – Rank Remaining SO_2 Control Options for Power Generation Turbines
AGDC has accepted the only feasible control options. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
According to the RBLC, clean fuels and good combustion practices are the applicable controls for SO_2 emissions for EUs 7 – 10. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and clean fuels are the only SO_2 emission control technologies installed on large combined cycle gas-fired turbines larger than 25 MW.

Applicant Proposal
AGDC proposed to use clean fuels and good combustion practices for the power generation turbines EUs 7 – 10 as BACT for reducing SO_2 emissions. AGDC will utilize only pipeline quality natural gas in the power generation turbines EUs 7 – 10 with a total sulfur content not to exceed 16 ppmv (1 grain/100 dscf).

Step 5 – Preliminary Selection of SO_2 BACT for Power Generation Turbines
The Department's preliminary finding is that BACT for SO_2 emissions from the combined cycle gas-fired combustion turbines greater than 25 MW is as follows:

(a) SO_2 emissions from EUs 7 – 10 shall be minimized by maintaining good combustion practices and burning pipeline quality natural gas with total sulfur content not to exceed 16 ppmv at all times the units are in operation; and

(b) Compliance with the proposed fuel sulfur content limit will be demonstrated with fuel shipment receipts and/or fuel test results for total sulfur content.

4.5 VOC

Possible VOC emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.210: large combined cycle and cogeneration natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 4-9.

Table 4-9: VOC Control for Large Combined Cycle Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits
Good Combustion & Clean Fuel	13	0.3 – 4 ppmv 0.0018 – 0.004 lb/MMBtu
Oxidation Catalyst	46	0.7 – 5 ppmv 0.0022 – 0.004 lb/MMBtu
No Controls	6	1 – 4 ppmv

Step 1 – Identify VOC Control Technologies for Power Generation Turbines

From research, the Department identified the following technologies as available for VOC control of large combined cycle natural gas-fired combustion turbines rated at greater than 25 MW:

(a) Oxidation Catalyst
Oxidation catalyst can control VOC emissions in the exhaust gas with the proper selection of catalyst. The oxidation reaction is spontaneous and does not require addition reagents. Formaldehyde and other organic HAPs can see reductions of 85% to 90%. The Department considers oxidation catalysts a technically feasible control technology for large combined cycle gas-fired turbines.

(b) Good Combustion Practices
VOC emissions in gas combustion turbines result from incomplete combustion. These VOCs can contain a wide variety of organic compounds, some of which are hazardous air pollutants. VOCs are discharged into the atmosphere when some of the fuel is un-combusted or only partially combusted. VOCs can be trace constituents of the fuel or products of pyrolysis of heavier hydrocarbons in the gas. In that complete combustion will reduce VOC emissions, good combustion practices are a feasible control method for large combined cycle gas-fired turbines.

Step 2 – Eliminate Technically Infeasible VOC Control Options for Power Generation Turbines

All control technologies identified are technically feasible for combined cycle gas-fired turbines larger than 25 MW.

Step 3 – Rank Remaining VOC Control Options for Power Generation Turbines

The following control technologies have been identified and ranked for control of VOC from the power generation turbines:

(a) Oxidation Catalyst (85% to 90% Control)
(b) Good Combustion Practices (Less than 85% Control)

Step 4 – Evaluate the Most Effective Controls
An oxidation catalyst will reduce VOC emissions from EUs 7 – 10 while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary. Turbine efficiency will be minimally impacted by the oxidation catalyst.

RBLC Review
A review of similar units in the RBLC indicates that an oxidation catalyst and good combustion practices are the principle VOC control technologies used on combined cycle gas-fired turbines larger than 25 MW.

Applicant Proposal
AGDC proposed to install an oxidation catalyst and use good combustion practices for the power generation turbines EUs 7 – 10 as BACT for reducing VOC emissions. VOC emissions from EUs 7 – 10 will not exceed 0.0022 lb/MMBtu.

Step 5 – Preliminary Selection of VOC BACT for Power Generation Turbines
The Department's preliminary finding is that BACT for VOC emissions from the combined cycle gas-fired combustion turbines greater than 25 MW is as follows:

(a) VOC emissions from EUs 7 – 10 shall be controlled by operating and maintaining an oxidation catalyst and good combustion practices at all times the units are in operation;

(b) VOC emissions from EUs 7 – 10 shall not exceed 0.0022 lb/MMBtu averaged over a 3-hour period (AP-42 VOC emission rate for gas-fired turbines); and

(c) Initial compliance with the proposed VOC emission limit will be demonstrated by conducting a performance test to obtain an emission rate, or supplying the Department with a vendor verification that the EUs will comply with the BACT limit.

4.6 GHG
Possible GHG emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.210: large combined cycle and cogeneration natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 4-10.

Table 4-10: GHG Control for Large Combined Cycle Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits
Good Combustion & Clean Fuel	30	850 – 1800 lb/MWh 112.6 – 151.2 lb/MMBtu
Carbon Capture and Sequestration (CCS)	0	N/A
No Control	5	774 – 1000 MWh

CO_2 and N_2O emissions are produced during natural gas combustion in gas turbines. Nearly all of the fuel carbon is converted to CO_2 during the combustion process, regardless of the firing configuration. CH_4 is also present in the exhaust gas and is thought to be unburned fuel in the case of natural gas.

Step 1 – Identify GHG Control Technologies for Power Generation Turbines
From research, the Department identified the following technologies as available for GHG control of large combined cycle natural gas-fired combustion turbines rated at greater than 25 MW:

(a) Thermal Efficiency and the Utilization of Thermal Energy and Electricity
The EPA Guidance states that options that improve the overall efficiency of the source or modification must be evaluated in the BACT analysis. These options can include technologies, processes, and practices at the emitting unit that allows the plant to operate more efficiently. In general, an efficient process requires less fuel for process heat, and therefore reduces the amount of CO_2 produced. In addition to energy efficiency of the individual emitting units, process improvements that impact the facility's higher-energy-using equipment, processes or operations could lead to reductions in emissions. There are a number of cycle configurations of a turbine as well as turbine designs that improves the efficiency of the operation.

1. Simple Cycle Gas-Fired Turbine (Baseline)
   In the baseline case, each turbine would operate in a simple cycle, which includes a single gas turbine to generate power. This configuration uses air as a diluent to reduce combustion flame temperatures. Fuel and air are pre-mixed in an initial stage resulting in a uniform, lean, unburned fuel/air mixture, which is then delivered to the combustor. The efficient combustion resulting from the process reduces the fuel consumption and CO_2 emissions.

2. Turbine with Waste Heat Recovery (Combined Cycle or Combined Heat and Power)
   In a combined cycle turbine, waste heat recovery units are added to the exhausts of the turbines, and recover previously unused energy to drive a steam turbine generator (STG). In a Combined Heat and Power (also known as cogeneration) turbine, waste heat from the turbine exhaust is put to a productive use such as heating a building, or used for a process that requires heat inputs. Utilizing waste heat in turbines leads to a more energy efficient operation because the additional power produced by the STG and heat produced by the turbine does not require additional fuel consumption. Besides the STG, this configuration requires additional equipment such as condensers, deaerator, and boiler feed pump, which increases the footprint and the cost of the facility. Furthermore, the additional steam turbine generation in a fixed electrical demand application forces gas turbine load reductions, increasing the gas turbine heat rates, and offsetting CO_2 reduction benefits.

3. Aeroderivative Turbine
   Aeroderivative turbines are similar to industrial turbines (also known as heavy duty or frame turbines) except their design is derived from aviation turbines, causing them to be lighter and generally smaller. Aeroderivative turbines have been used in gas compression and electrical power generation operations due to their ability to be shut

down and handle load changes quickly. These turbines are also used in the marine industry due to their reduced weight. In addition to being lighter weight than traditional industrial turbines, these turbines are generally more efficient than industrial turbines of comparable size and capacity. This leads to less fuel consumption to achieve the same power output, resulting in a reduction of GHG emissions in the 4% to 12% range.

4. Organic Rankine Cycle (ORC)
ORC uses a refrigerant working fluid that is heated by engine exhaust gas from the natural gas fired turbines, and expands through a turbine connected to the engine shaft. The ORC system involves the same components as in a conventional steam power plant; however, instead of using water as a working fluid, ORC uses a refrigerant with a boiling point lower than that of water, and enables recovery of heat from lower-temperature heat sources. The ORC offers reduced equipment size compared to the steam cycle. This equipment is at their best in air-cooled applications where the heat source is below approximately 400ºF. The heat source for this application is the gas turbine exhaust, and is approximately 800 to 1,000 ºF, which would require an additional thermal fluid loop.

   A disadvantage of the ORC is that, the configuration requires more fuel consumption compared to the steam cycle, and operation when ambient temperature is below 40ºF (approximately 50% of the year) makes the system less efficient. Also, additional heat exchangers may be needed to preheat the ORC working fluid and the combustion air, which would increase the cost and complexity of the system. The Department does not consider ORC as a technically feasible technology for control of GHGs.

(b) Carbon Capture and Sequestration (CCS)
The EPA Guidance classifies CCS as "an add-on pollution control technology that is 'available' for facilities emitting CO_2 in large amounts." AGDC has included a description of CCS, and a review of the technology in their permit application.

CCS is a broad term that includes a number of technologies that involves three general steps: 1) capturing the carbon dioxide directly at its source and compressing it, 2) transporting, and 3) storing it in non-atmospheric reservoirs. Capture, the most energy-intensive of all the processes, can be done either through pre-combustion methods or post-combustion methods. Pre-combustion requires the use of oxygen instead of air to combust the fuel. In general, pre-combustion reduces the energy required and the cost to remove CO_2 emissions from the combustion process. The concentration of CO_2 in the untreated gas stream is higher in pre-combustion capture, thereby requiring less and cheaper equipment. The other method is post-combustion, applied to conventional combustion techniques using air and carbon-containing fuels in order to isolate CO_2 from the combustion exhaust gases.

After capture, the CO_2 is compressed to a near-liquid state, and transported via pipeline to a designated storage area. These reservoirs are deep enough for the pressure of the earth to keep it in a liquidized form where it will be sequestered for thousands of years.

Depleted oil and gas reservoirs are the most practical places for storing CO_2 emissions that would otherwise be emitted back into the atmosphere. Other options for storage include deep saline formations, un-mineable coal seams, and even offshore storage. The stored CO_2 is expected to remain underground for as long as thousands, even millions of years.

The Department's research did not identify CCS as a control technology used to control GHG emissions from turbines installed at any facility in the RBLC database. However, AGDC submitted an economic analysis for CCS on the gas-fired turbines that will be advanced to the next step and evaluated.

(c) Good Combustion Practices (GCP) and Clean Fuels
☑ Discussed in detail in CO BACT Section 3.2, as well as the fuel specifications portion of particulate BACT Section 3.3. GCP and clean fuels is a common technique for controlling GHG emissions. GHG emissions in the exhaust of liquid or gas-fired turbines are directly related to the carbon content in the fuel. Natural gas has the lowest amount of GHG emissions per Btu of energy of any fossil fuel, and is considered a feasible control technology for the power generation turbines.

Step 2 – Eliminate Technically Infeasible GHG Control Options for Power Generation Turbines
As explained in Step 1, ORC is not a feasible technology to control GHG emissions from combined cycle gas-fired turbines larger than 25 MW.

Aeroderivative turbine: the facility is currently designed to use four simple cycle turbines to generate power for the facility. Requiring the power generation turbines to be aeroderivative models would fundamentally redefine the project, and is therefore not considered as an option in the BACT analysis.

Step 3 – Rank Remaining GHG Control Options for Power Generation Turbines
The following control technologies have been identified and ranked for control of GHG from the power generation turbines:

(a) CCS (80% - 90% Control)
(b) GCP and Clean Fuels (<80% Control)

Step 4 – Evaluate the Most Effective Controls
According to the RBLC clean fuels and good combustion practices are the applicable controls for GHG emissions for EUs 7 – 10. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and clean fuels are the only GHG emission control technologies currently installed on combined cycle gas-fired turbines larger than 25 MW.

Applicant Proposal

AGDC provided an economic analysis of the top most effective control technology CCS for a combination of the simple cycle compressor turbines EUs 1 – 6 and the combined cycle power generation turbines EUs 7 – 10 to demonstrate that the use of the most effective control (CCS) is not economically feasible. The economic analysis included cost data from a study conducted for AGDC's Gast Treatment Plant by URS Corporation in 2010 titled, "Alaska Pipeline Project Gas Treatment Plant: CO_2 Capture Study" as well as cost data from the Golden Pass LNG Project PSD Permit Application. AGDC noted that the cost for CCS alone for the turbines at the Liquefaction Plant would be more than 5 billion dollars. AGDC calculated that a 90% control of emissions would avoid 3.8 million tons of CO_2 per year at the cost of more than $165/ton. A summary of AGDC's analysis is shown in Table 4-11.

Table 4-11: AGDC Economic Analysis for Technically Feasible GHG Controls (EUs 1 – 10)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
CCS	419,970	3,779,734	$5,018,084,403	$623,269,718	$165
Capital Recovery Factor = 0.0858 (7.00% interest rate for a 25 year equipment life)					

AGDC proposed to use clean fuels (pipeline quality natural gas) and good combustion practices for the power generation turbines EUs 7 – 10 as BACT for reducing GHG emissions. GHG emissions from EUs 7 – 10 will not exceed 117.1 lb/MMBtu, which is the CO_2 equivalent (CO_2e) emissions rates for burning natural gas in 40 CFR Part 98: Mandatory Greenhouse Gas Reporting. The total CO_2e emissions rate is calculated with the equation $CO_2(1) + CH_4(25) + N_2O(298)$.

Department Evaluation of BACT for GHG Emissions from Gas-Fired Turbines

The Department used the lower capital investment cost from the CO_2 Capture Study for the Gas Treatment Plant of $3.6 billion to create an economic analysis. The Department's economic analysis used the current bank prime interest rate of 3.25%, an equipment life of 25 years, and assumed a 90% control of CO_2 emissions. A summary of the Department's cost analysis for all turbines EUs 1-10 combined is shown in Table 4-12.

Table 4-12: Department Economic Analysis for Technically Feasible GHG Controls (EUs 1 – 10)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
CCS	421,287.0	3,791,583.4	$3,631,800,000	$534,314,775	$140.9
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analysis, combined with the fact that there are no examples of CCS being used to control GHG emissions from any facility in the RBLC, indicates the level of GHG reduction does not justify the use of CCS as BACT for the turbines at the Liquefaction Plant.

Step 5 – Preliminary Selection of GHG BACT for Power Generation Turbines
The Department's preliminary finding is that BACT for GHG emissions from the combined cycle gas-fired combustion turbines greater than 25 MW is as follows:

(a) GHG emissions from EUs 7 – 10 shall be minimized by maintaining good combustion practices and burning clean fuels at all times the units are in operation; and

(b) GHG emissions from EUs 7 – 10 shall not exceed 117.1 lb/MMBtu averaged over a 3-hour period.

5.0 LIMITED USE DIESEL-FIRED ENGINES

The Liquefaction Plant will have two engines on site, including one 575 hp diesel fire pump engine (EU 11), and one 300 hp diesel-fired auxiliary air compressor engine (EU 12). Both of EUs 11 and 12 are considered limited use diesel-fired engines. The fire pump, and auxiliary air compressor engines will emit CO, NOx, SO_2, particulates, VOC, and GHG. The following sections provide the BACT review for each of these pollutants.

5.1 NOx

Possible NOx emission control technologies for limited use diesel engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17:110 to 17.190: Large Internal Combustion Engines (>500 hp) and 17:210: Small Fuel Oil-Fired Internal Combustion Engines (<500 hp). The search results for the engines greater than 500 hp and smaller than 500 hp are contained in Tables 5-1 and 5-2 respectively.

Table 5-1: 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

Table 5-2: NOx Controls 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 good combustion practices and Federal emissions standards are the principle NOx control technologies installed on diesel-fired engines. The lowest emission rate listed in the RBLC is 0.5 g/hp-hr for large diesel engines and 2.0 g/hp-hr for small diesel engines.

Step 1 – Identify NOx Control Technologies for Diesel-Fired Engines

From research, the Department identified the following technologies as available for NOx control of diesel engines:

(a) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT Section 3.1 for the large combined cycle natural gas-fired combustion turbines and will not be repeated here. The Department considers SCR a technically feasible control technology for both the large and small 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. Today, manufacturers typically design new diesel engines with a turbocharger and aftercooler technology as part of standard equipment. The Department considers turbocharger and aftercooler a technically feasible control technology for both the large and small 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, 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 both the large and small diesel-fired engines.

(f) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. As stated above in Section 5.0, all of the diesel-fired engines at the Liquefaction Plant are considered limited use engines. The Department considers limited operation a technically feasible control technology for both the large and small diesel-fired engines.

(g) Good Combustion Practices
The theory of GCPs was discussed in detail in the CO BACT Section 3.2 for the simple cycle natural gas-fired turbines and will not be repeated here. The Department considers GCPs a technically feasible control technology for both the large and small diesel-fired engines.

Step 2 – Eliminate Technically Infeasible NOx Control Options for Diesel-Fired Engines
As explained in Step 1, the Department does not consider fuel injection timing retard and ignition timing retard as technically feasible technologies to control NOx emissions from the diesel-fired engines.

Step 3 – Rank Remaining NOx Control Options for Diesel-Fired Engines
The following control technologies have been identified and ranked for control of NOx from the engines:

(a) Limited Operation	(94% Control)
(b) Selective Catalytic Reduction	(90% Control)
(c) Good Combustion Practices	(Less than 40% Control)
(d) Turbocharger and Aftercooler	(6% – 12% Control)
(e) Federal Emission Standards	(Baseline)

Step 4 – Evaluate the Most Effective Controls
SCR is the most effective NOx control for diesel-fired engines after limited operation. Environmental impacts include the SCR system increasing exhaust back pressure which decreases the engine’s efficiency requiring additional fuel consumption, the disposal of the spent SCR catalyst when replacement becomes necessary, as well as ammonia slip from the SCR system.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices is the principle NOx control technology used on diesel-fired engines.

Applicant Proposal
AGDC provided an economic analysis of the topmost effective control technology SCR combined with limited operation of 500 hours per year assumed for the largest engine (EU 11), to demonstrate that the use of the most effective control (SCR) is not economically feasible for

these limited use diesel engines. A summary of the analyses for the diesel firewater pump EU 11 can be found in Table 5-3.

Table 5-3: AGDC Economic Analysis for Technically Feasible NOx Controls (EU 11)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.06	.90	$101,211	$67,554	$80,320
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

AGDC contends that the economic analysis indicates the level of NOx reduction from SCR does not justify the use of SCR for the limited use diesel engines based on the excessive cost per ton of NOx removed per year.

AGDC proposes the following as BACT for NOx emissions from the diesel engines:

(a) NOx emissions from the operation of the diesel engines EUs 11 and 12 will be controlled through limited operation of 500 hours per 12-month rolling period per unit and by utilizing good combustion practices;

(b) NOx emissions from the diesel firewater pump engine EU 11 will not exceed 3.56 g/hp-hr @ 15% O_2; and

(c) NOx emissions from the auxiliary air compressor diesel engine EU 12 will not exceed 0.45 g/hp-hr @ 15% O_2.

Department Evaluation of BACT for NOx Emissions from Diesel-Fired Engines
The Department revised the cost analysis to reflect the equipment life revised to a 25-year lifespan, to account for differences in PTE, and adjusted the interest rate to the current bank prime interest rate of 3.25%. A summary of the analysis for the diesel firewater pump EU 11 can be found in Table 5-4.

Table 5-4: Department Economic Analysis for Technically Feasible NOx Controls (EU 11)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.08	1.1	$101,211	$63,923	$60,881
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analysis indicates the level of NOx reduction does not justify the use of SCR as BACT for any of the limited use diesel engines at the Liquefaction Plant.

Step 5 – Selection of NOx BACT for Diesel-Fired Engines
The Department's finding is that BACT for NOx emissions from the limited use diesel engines is as follows:

(a) NOx emissions from the operation of the diesel engine EUs 11 and 12 shall be controlled by maintaining good combustion practices at all times the units are in operation;

(b) Limit operation of the diesel-fired engines EUs 11 and 12 to no more than 500 hours per 12-month rolling period per engine;

(c) NOx emissions from diesel firewater pump engine EU 11 will not exceed 3.6 g/hp-hr @ 15% O_2 ((95% of NMHC + NOx from Table 4 of NSPS Subpart IIII, also equivalent to EPA Tier 3, includes 25% not to exceed factor of safety); EPA Tier 4 Final, includes 25% not to exceed factor of safety);

(d) NOx emissions from the auxiliary air compressor diesel engine EU 12 will not exceed 0.45 g/hp-hr @ 15% O_2 (EPA Tier 4 Final, includes 50% not to exceed factor of safety); and

(e) Initial compliance with the proposed NOx emission limits will be demonstrated by purchasing engines certified to meet the appropriate EPA Tier emissions standards.

5.2 CO

Possible CO emission control technologies for limited use diesel engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110 to 17:190: Large Internal Combustion Engines (>500 hp) and 17.210: Small Fuel Oil-Fired Internal Combustion Engines (<500 hp). The search results for the diesel engines greater than 500 hp and smaller than 500 hp are contained in Tables 5-5 and 5-6 respectively.

Table 5-5: CO Controls for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Oxidation Catalyst	1	0.13
Federal Emission Standards, Clean Fuel, & Good Combustion Practices	56	0.31 - 8.5
Operational Limit	1	2.6
No Control Specified	15	0.26 – 2.6

Table 5-6: CO Controls for Small Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Federal Emission Standards, Clean Fuel, & Good Combustion Practices	43	0.53 - 3.7
Operational Limit	2	2.6 - 4.1
Turbocharger & Intercooler	1	0.45
No Control Specified	16	0.5 - 3.1

Step 1 – Identify CO Control Technologies for Diesel-Fired Engines

From research, the Department identified the following technologies as available for CO control of diesel-fired engines:

(a) Oxidation Catalyst
The theory of oxidation catalysts were discussed in detail in the CO BACT section 3.2 for the large simple cycle natural gas-fired combustion turbines. Oxidation catalysts oxidize CO and hydrocarbon compounds to carbon dioxide and water vapor. The reaction is

spontaneous and no reactants are required. CO catalysts can achieve up to 90% reduction in CO emissions. The Department considers oxidation catalysts to be a technically feasible control technology for both the large and small sized diesel engines.

(b) Good Combustion Practices (GCP) and clean fuel
The theory of GCPs and clean fuel was discussed in detail in CO BACT section 3.2 for the large simple cycle natural gas-fired combustion turbines and will not be repeated here. The Department's search of the RBLC database indicated that GCPs and clean fuel are commonly used to control CO emissions for diesel engines. Therefore, the Department considers GCPs and clean fuel to be a technically feasible control technology for both the large and small sized diesel engines.

(c) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. As stated above in Section 5.0, all of the diesel-fired engines at the Liquefaction Plant are considered limited use engines. The Department considers limited operation a technically feasible control technology for both the large and small diesel-fired engines.

(d) Federal Emission Standards
RBLC CO 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, 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 of Subpart IIII as a technically feasible control technology for both the large and small diesel-fired engines.

Step 2 – Eliminate Technically Infeasible CO Control Options for Diesel-Fired Engines
All of the control technologies identified are technically feasible for the diesel engines.

Step 3 – Rank Remaining CO Control Options for Diesel-Fired Engines
The following control technologies have been identified and ranked for control of CO from the diesel-fired engines:

(a) Limited Operation	(94% Control)
(b) Oxidation Catalyst	(90% Control)
(c) Good Combustion Practices	(Less than 90% Control)
(d) Federal Emission Standards	(Baseline)

Step 4 – Evaluate the Most Effective Controls
An oxidation catalyst will reduce CO emissions from EUs 11 and 12 while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary. Engine efficiency will be minimally impacted by the oxidation catalyst.

RBLC Review
A review of similar units in the RBLC indicates good combustion practices with clean fuel and following Federal emissions standards are the principle CO control for both large and small sized diesel engines.

Applicant Proposal
AGDC provided economic analyses of the most effective control technology - oxidation catalyst with limited operation of 500 hours per year assumed for each engine to demonstrate that the use of an oxidation catalyst is not economically feasible for these limited use diesel engines. A summary of the analyses for the diesel firewater pump engine EU 11 can be found in Table 5-7 and the auxiliary air compressor diesel engine EU 12 in Table 5-8.

Table 5-7: AGDC Economic Analysis for Technically Feasible CO Controls (EU 11)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.25	0.58	$25,507	$6,857	$11,883
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

Table 5-8: AGDC Economic Analysis for Technically Feasible CO Controls (EU 12)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.13	0.30	$25,507	$6,857	$22,671
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

AGDC contends that the economic analysis indicates the level of CO reduction from an oxidation catalyst does not justify the use of an oxidation catalyst for the engine EUs 11 and 12 based on the excessive cost per ton of CO removed per year.

AGDC proposes the following as BACT for CO emissions from the diesel engines:

(a) CO emissions from the operation of the diesel engines EUs 11 and 12 shall be controlled through limited operation of 500 hours per 12-month rolling period per unit and by maintaining good combustion control practices at all times the units are in operation;

(b) CO emissions from the diesel firewater pump engine EU 11 will not exceed 3.25 g/hp-hr @ 15% O_2; and

(c) NOx emissions from the auxiliary air compressor diesel engine EU 12 will not exceed 3.26 g/hp-hr @ 15% O_2.

Department Evaluation of BACT for CO Emissions from Diesel-Fired Engines
The Department revised the cost analyses to include the CO and VOC emissions removed into one cost calculation, to reflect the equipment life revised to a 25 year lifespan, to account for

differences in PTE and greater reduction efficiency achievable with catalytic oxidation, and adjusted the interest rate to the current bank prime interest rate of 3.25%. A summary of the analyses for the diesel firewater pump engine EU 11 can be found in Table 5-9 and the auxiliary air compressor diesel engine EU 12 in Table 5-10.

Table 5-9: Department Economic Analysis for Technically Feasible CO Controls (EU 11)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.22	0.87	$25,507	$5,956	$6,836
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 5-10: Department Economic Analysis for Technically Feasible CO Controls (EU 12)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.11	0.46	$25,507	$5,956	$12,970
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analysis indicates the level of CO and VOC reduction does not justify the use of an oxidation catalyst as BACT for the auxiliary air compressor diesel engine EU 12. The Department finds that the removal cost of $6,836 per ton for the installation of an oxidation catalyst on the diesel firewater pump engine EU 11 is reasonable, and the RBLC does contain an example of a large diesel engine with oxidation catalyst used to control CO emissions. However, that single case of a large diesel engine with an oxidation catalyst in the RBLC was from the Donlin Gold Project in Alaska, which is permitted for considerably larger 17 MW diesel engines used for continuous power production, as opposed to a firewater pump engine limited to 500 hours per year at the Liquefaction Plant. Therefore, the Department considers the 500 hour per year limit on EU 11 BACT for CO emissions.

Step 5 – Selection of CO BACT for Diesel-Fired Engines

The Department's finding is that BACT for CO emissions from the limited use diesel engines is as follows:

(a) CO emissions from the operation of the diesel-fired engines EUs 11 and 12 shall be controlled by maintaining good combustion practices at all times the units are in operation;

(b) Limit operation of the diesel-fired engines EUs 11 and 12 to no more than 500 hours per 12-month rolling period per engine;

(c) CO emissions from the diesel firewater pump engine EU 11 will not exceed 3.3 g/hp-hr @ 15% O_2 (Table 4 from NSPS Subpart IIII, also equivalent to EPA Tier 3, includes 25% not to exceed factor of safety);

(d) CO emissions from the auxiliary air compressor diesel engine EU 12 will not exceed 3.3 g/hp-hr @ 15% O_2 (EPA Tier 4 Final, includes 25% not to exceed factor of safety); and

(e) Initial compliance with the proposed CO emission limits will be demonstrated by purchasing engines certified to meet the appropriate EPA Tier emissions standards.

5.3 Particulates
Possible particulate emission control technologies for limited use diesel engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110 to 17:190: Large Internal Combustion Engines (>500 hp) and 17.210: Small Fuel Oil-Fired Internal Combustion Engines (<500 hp). The search results for the diesel engines greater than 500 hp and smaller than 500 hp are contained in Tables 5-11 and 5-12 respectively.

Table 5-11: Particulate Control for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Diesel Particulate Filter	2	0.15
Federal Emission Standards, Good Combustion Practices, & Clean Fuel	113	0.015 – 0.43
Operational Limit	2	0.15
No Control Specified	32	0.025 – 0.32

Table 5-12: Particulate Control for Small Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Diesel Particulate Filter	2	0.15
Federal Emission Standards, Good Combustion Practices, & Clean Fuel	89	0.075 – 0.40
Operational Limit	2	0.15
No Control Specified	32	0.11 – 1.0

Step 1 – Identify Particulate Control Technologies for Diesel-Fired Engines
From research, the Department identified the following technologies as available for particulate control of diesel engines:

(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 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 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 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 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 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 diesel-fired engines.

(g) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. As stated above in Section 5.0, all of the diesel-fired engines at the Liquefaction Plant are considered limited use engines. The Department considers limited operation a technically feasible control technology for the diesel-fired engines.

(h) Good Combustion Practices
As discussed in detail in the CO BACT Section 3.2, Proper management of the combustion process will result in a reduction of particulates. The Department considers good combustion practices a technically feasible control technology for the diesel-fired engines.

Step 2 – Eliminate Technically Infeasible Particulate Control Options for Diesel-Fired Engines

All control technologies identified are technically feasible to control particulate emissions from the diesel engines.

Step 3 – Rank Remaining Particulate Control Options for Diesel-Fired Engines
The following control technologies have been identified and ranked for control of particulate emissions from the diesel engines.

(a) Limited Operation (94% Control)
(b) Diesel Particulate Filters (85% Control)
(c) Good Combustion Practices (Less than 40% Control)
(d) Diesel Oxidation Catalyst (30% Control)
(e) Low Ash Diesel (25% Control)
(f) Positive Crankcase Ventilation (10% Control)
(g) Federal Emission Standards (Baseline)

Step 4 – Evaluate the Most Effective Controls
Limited operation and diesel particulate filters will reduce particulate emissions from EUs 11 and 12 while having minimal environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that Federal emission standards, good combustion practices, and burning of ULSD fuel are the principle particulate control technologies installed on diesel engines.

Applicant Proposal
AGDC provided an economic analysis of the topmost effective control technology DPF with limited operation of 500 hours per year assumed for the largest engine (EU 11), to demonstrate that the use of a DPF is not economically feasible for these limited use diesel engines. A summary of the analyses for the diesel firewater pump EU 11 can be found in Table 5-13.

Table 5-13: AGDC Economic Analysis for Feasible Particulate Controls (EU 11)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
DPF	0.005	0.05	$43,770	$8,202	$191,617
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

AGDC contends that the economic analysis indicates the level of particulate emissions reduction from a DPF does not justify the use of DPF for the limited use diesel engines based on the excessive cost per ton of particulate emissions removed per year.

AGDC proposes the following as BACT for particulate emissions from the diesel-fired engines:

(a) Particulate emissions from the operation of the diesel engines EUs 11 and 12 shall be controlled through limited operation of 500 hours per 12-month rolling period per unit and by maintaining good combustion control practices;

(b) Particulate emissions from the diesel firewater pump engine EU 11 will not exceed 0.19 g/hp-hr @ 15% O_2; and

(c) Particulate emissions from the auxiliary air compressor diesel engine EU 12 will not exceed 0.022 g/hp-hr @ 15% O_2.

Department Evaluation of BACT for Particulate Emissions from Diesel-Fired Engines
The Department revised the cost analysis to reflect the equipment life revised to a 25-year lifespan, to account for differences in PTE, and adjusted the interest rate to the current bank prime interest rate of 3.25%. A summary of the analyses for the diesel firewater pump EU 11 can be found in Table 5-14.

Table 5-14: Department Economic Analysis for Feasible Particulate Controls (EU 11)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
DPF	0.019	0.17	$43,770	$6,655	$39,331
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analysis indicates the level of particulate emissions reduction does not justify the use of a DPF as BACT for any of the limited use diesel engines at the Liquefaction Plant.

Step 5 – Selection of Particulate BACT for Diesel-Fired Engines
The Department's finding is that BACT for particulate emissions from the limited use diesel engines is as follows:

(a) Particulate emissions from the operation of the diesel engines EUs 11 and 12 shall be controlled by maintaining good combustion practices and burning ULSD fuel at all times the units are in operation;

(b) Limit operation of the diesel-fired engines EUs 11 and 12 to no more than 500 hours per 12-month rolling period per engine;

(c) Particulate emissions from the diesel firewater pump engine EU 11 will not exceed 0.19 g/hp-hr @ 15% O_2 (Table 4 of NSPS Subpart IIII, also equivalent to EPA Tier 3, includes 25% not to exceed factor of safety);

(d) Particulate emissions from the auxiliary air compressor diesel engine EU 12 will not exceed 0.022 g/hp-hr @ 15% O_2 (EPA Tier 4 Final, includes 50% not to exceed factor of safety); and

(e) Initial compliance with the proposed particulate emission limits will be demonstrated by purchasing engines certified to meet the appropriate EPA Tier emissions standards.

5.4 SO_2
Possible SO_2 emission control technologies for limited use 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 to 17:190: Large Internal Combustion Engines (>500 hp) and 17.210: Small Fuel Oil-Fired Internal Combustion Engines (<500 hp). The search results for the diesel engines greater than 500 hp and smaller than 500 hp are contained in Tables 5-15 and 5-16 respectively.

Table 5-15: SO_2 Controls for Large Diesel Engines

Control Technology	Number of Determinations	Emission Limits (sulfur content in fuel, ppm)
Ultra-Low Sulfur Diesel, Limited Operations, and Good Combustion Practices	27	≤15 – 500

Table 5-16: SO_2 Controls for Small Diesel Engines

Control Technology	Number of Determinations	Emission Limits (sulfur content in fuel, ppm)
Ultra-Low Sulfur Diesel, Limited Operations, and Good Combustion Practices	21	≤15 – 500

Step 1 – Identify SO_2 Control Technologies for Diesel-Fired Engines
From research, the Department identified the following technologies as available for control of SO_2 emissions from diesel-fired engines:

(a) Ultra-Low Sulfur Diesel (ULSD) and Federal Emission Standards
SO_2 emissions in the exhaust of fuel-fired engines are directly related to the levels of sulfur in fuel. As such, fuel specifications are the primary method of controlling SO_2 emissions in engines. ULSD has a maximum sulfur content of 15 ppm (0.0015 percent by weight). The federal emission standards require all diesel-fired engines subject to NSPS Subpart IIII with a displacement of less than 30 liters per cylinder to burn ULSD (40 C.F.R. 60.4207(b)). Therefore, the Department considers ULSD a technically feasible control technology for the 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 diesel-fired engines.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the CO BACT Section 3.2 for simple cycle 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 diesel-fired engines.

Step 2 – Eliminate Technically Infeasible SO_2 Control Technologies for the Diesel Engines
All identified control technologies identified are technically feasible for the diesel-fired engines.

Step 3 – Rank Remaining SO_2 Control Technologies for Diesel-Fired Engines
The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from the diesel-fired engines.

(a) ULSD (including Federal Standards) (99% Control)
(b) Limited Operation (94% Control)
(c) Good Combustion Practices (Less than 40% Control)

Step 4 – Evaluate the Most Effective Controls
According to the RBLC, ULSD and good combustion practices are the applicable controls for SO_2 emissions for the diesel engines EUs 11 and 12. Since these are not add-on controls, there are no additional environmental impacts.

Applicant Proposal
AGDC proposed to use ULSD, limit operations of each engine to 500 hours per 12-month rolling period per unit, and maintain good combustion control practices for the limited use diesel engines EUs 11 and 12 as BACT for reducing SO_2 emissions.

Step 5 – Selection of SO_2 BACT for Diesel-Fired Engines
The Department's finding is that BACT for SO_2 emissions from the limited use diesel-fired engines is as follows:

(a) SO_2 emissions from the operation of the diesel-fired engines EUs 11 and 12 shall be controlled by only combusting ULSD at all times the units are in operation;
(b) Limit operation of the diesel-fired engines EUs 11 and 12 to no more than 500 hours per 12-month rolling period per engine;
(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.

5.5 VOC
Possible VOC emission control technologies for limited use 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 to 17:190: Large Internal Combustion Engines (>500 hp) and 17.210: Small Fuel Oil-Fired Internal Combustion Engines (<500 hp). The search results for the diesel engines greater than 500 hp and smaller than 500 hp are contained in Tables 5-17 and 5-18 respectively.

Table 5-17: VOC Control for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Oxidation Catalyst	1	0.21
NSPS IIII	12	0.03 – 0.3
Good Combustion Practices	17	0.015 – 1.0
No Control Specified	26	0.07 – 0.32

Table 5-18: VOC Control for Small Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Federal Emission Standards	9	0.15 – 0.37
Good Combustion Practices	13	0.05 - 1.6
No Control Specified	8	0.15 - 1.14

Step 1 – Identify VOC Control Technologies for Diesel-Fired Engines
From research, the Department identified the following technologies as available for VOC control of diesel-fired engines:

(a) Oxidation Catalyst
The theory of oxidation catalysts were discussed in detail in the CO BACT section 3.2 for the large simple cycle natural gas-fired combustion turbines. Oxidation catalysts oxidize CO and hydrocarbon compounds to carbon dioxide and water vapor. The reaction is spontaneous and no reactants are required. The Department considers oxidation catalysts to be a technically feasible control technology for both the large and small sized diesel engines.

(b) Good Combustion Practices
The theory of GCPs was discussed in detail in CO BACT section 3.2 for the large simple cycle natural gas-fired combustion turbines and will not be repeated here. The Department's search of the RBLC database indicated that GCPs are commonly used to control VOC emissions for diesel engines. Therefore, the Department considers GCPs and clean fuel to be a technically feasible control technology for both the large and small sized diesel engines.

(c) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. As stated above in Section 5.0, all of the diesel-fired engines at the Liquefaction Plant are considered limited use engines. The Department considers limited operation a technically feasible control technology for both the large and small diesel-fired engines.

(d) Federal Emission Standards
RBLC VOC 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, 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 both the large and small diesel-fired engines.

Step 2 – Eliminate Technically Infeasible VOC Control Options for Diesel-Fired Engines
All of the control technologies identified are technically feasible for the diesel engines.

Step 3 – Rank Remaining VOC Control Options for Diesel-Fired Engines
The following control technologies have been identified and ranked for control of VOCs from the diesel-fired engines:

(a) Limited Operation (94% Control)
(b) Oxidation Catalyst (90% Control)
(c) Good Combustion Practices (Less than 90% Control)
(d) Federal Emissions Standards (Baseline)

Step 4 – Evaluate the Most Effective Controls
A review of similar units in the RBLC indicates add-on control technology (oxidation catalyst) is not practical for limited use engines. Based on the small potential to emit associated with these units (less than 10% when compared to CO emissions for which a cost demonstration is made for oxidation catalysts), it is not a cost effective control technology for the limited use diesel-fired engines.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and following the federal emissions standards are the primary VOC control technologies for diesel-fired engines.

Applicant Proposal
AGDC proposed to use good combustion practices, limit operations of each engine to 500 hours per year, and install engines certified to meet NSPS Subpart IIII as BACT for VOC emissions. Assuming that 5% of the total NOx plus NMHC (non-methane hydrocarbons) emissions are VOC emissions, this equates to the following emissions rates:

(a) VOC emissions from the operation of the diesel engines EUs 11 and 12 shall be controlled through limited operation of 500 hours per 12-month rolling period per unit and by maintaining good combustion control practices at all times the units are in operation;

(b) VOC emissions from the diesel firewater pump engine EU 11 will not exceed 0.188 g/hp-hr @ 15% O_2;

(c) VOC emissions from the auxiliary air compressor diesel engine EU 12 will not exceed 0.213 g/hp-hr @ 15% O_2; and

Step 5 – Selection of VOC BACT for Diesel-Fired Engines
The Department's finding is that BACT for VOC emissions from the limited use diesel-fired engines is as follows:

(a) VOC emissions from the operation of the diesel-fired engines EUs 11 and 12 shall be controlled by maintaining good combustion practices at all times the units are in operation;

(b) Limit operation of the diesel-fired engines EUs 11 and 12 to no more than 500 hours per 12-month rolling period per engine;

(c) VOC emissions from the diesel firewater pump engine EU 11 will not exceed 0.19 g/hp-hr @ 15% O_2 (5% of NOx + NMHC value from Table 4 from NSPS Subpart IIII, also equivalent to EPA Tier 3, includes 25% not to exceed factor of safety);

(d) VOC emissions from the auxiliary air compressor diesel engine EU 12 will not exceed 0.22 g/hp-hr @ 15% O_2 (EPA Tier 4 Final, includes 50% not to exceed factor of safety); and

(e) Initial compliance with the proposed VOC emission limits will be demonstrated by purchasing engines certified to meet the appropriate EPA Tier emissions standards.

5.6 GHG

Possible GHG emission control technologies for limited use 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 to 17:190: Large Internal Combustion Engines (>500 hp) and 17.210: Small Fuel Oil-Fired Internal Combustion Engines (<500 hp). The search results for the diesel engines greater than 500 hp and smaller than 500 hp are contained in Tables 5-19 and 5-20 respectively.

Table 5-19: GHG Control for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits
Federal Emission Standards	6	37 – 432 tpy
Good Combustion Practices	21	72 – 1,299,630 tpy
No Control Specified	14	14 – 7,194 tpy 162.8 – 163.6 lb/MMBtu

Table 5-20: GHG Control for Small Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits
Good Combustion Practices	26	0.29 – 3,083 tpy
NSPS IIII	3	10 – 72 tpy
Limited Operation	5	5 – 58 tpy
No Control Specified	7	91 – 516 tpy 162.9 – 164.9 lb/MMBtu

Step 1 – Identify GHG Control Technologies for Diesel-Fired Engines

From research, the Department identified the following technologies as available for GHG control of diesel-fired engines:

(a) Carbon Capture and Storage
CCS was discussed in detail in the GHG BACT Section 4.6 for simple cycle turbines, and will not be repeated here. The Department's research did not identify CCS as a control technology used to control GHG emissions from diesel-fired engines or any other emission unit type installed at any facility in the RBLC database. Additionally, the Department performed an economic analysis for CCS on the turbines EUs 1 – 10 at the Liquefaction Plant and found the costs to economically infeasible. Therefore, the Department considers this technology to be both technologically and economically infeasible for controlling GHG emissions from the smaller diesel-fired engines.

(b) Good Combustion Practices
Discussed in detail in CO BACT Section 3.2, as well as the fuel specifications portion of particulate BACT Section 3.3. GCP and clean fuels is a common technique for controlling GHG emissions. GHG emissions in the exhaust of engines are directly related to the carbon content in the fuel. Good combustion practices are considered a feasible control technology for the diesel-fired engines.

Step 2 – Eliminate Technically Infeasible GHG Control Options for Diesel-Fired Engines
As explained in Step 1, CCS is not considered a technically feasible technology to control GHG emissions from diesel-fired engines.

Step 3 – Rank Remaining GHG Control Options for Diesel-Fired Engines
AGDC has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
According to the RBLC, good combustion practices are the applicable controls for GHG emissions for EUs 11 and 12. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices is the principle control method for GHG from diesel-fired engines.

Applicant Proposal
AGDC proposed to use good combustion practices and limited operation of 500 hours per 12-month rolling period for each engine for EUs 11 and 12 as BACT for reducing GHG emissions. GHG emissions from EUs 11 and 12 will not exceed 163.6 lb/MMBtu, which is the CO_2e emissions rates for burning diesel fuel in 40 CFR Part 98: Mandatory Greenhouse Gas Reporting. The total CO_2e emissions rate is calculated with the equation $CO_2(1) + CH_4(25) + N_2O(298)$.

Step 5 – Selection of GHG BACT for Diesel-Fired Engines
The Department's finding is that BACT for GHG emissions from the diesel-fired engines is as follows:

(a) GHG emissions from EUs 11 and 12 shall be controlled by maintaining good combustion practices at all times the units are in operation;

(b) Limit operation of the diesel-fired engines EUs 11 and 12 to no more than 500 hours per 12-month rolling period per engine; and

(c) GHG emissions from EUs 11 and 12 shall not exceed 163.6 lb/MMBtu averaged over a 3-hour period.

6.0 VENT GAS DISPOSAL (THERMAL OXIDIZER)

The Liquefaction Plant will utilize a thermal oxidizer (EU 13) to control off-gas emissions from the condensate tank. The thermal oxidizer will prevent the direct relief to the atmosphere of vent gases that contain VOC and GHG (in the form of CH_4). The thermal oxidizer will emit CO, NOx, SO_2, particulates, VOC, and GHG. The following sections provide the BACT review for each of these pollutants.

6.1 NOx

Possible NOx emission control technologies for the thermal oxidizer were obtained from the RBLC. The RBLC was searched for all processes containing the word thermal oxidizer. The search results were then filtered to include only emissions units with thermal oxidizers. The search results for the thermal oxidizer are summarized in Table 6-1.

Table 6-1: NOx Controls for Thermal Oxidizers

Control Technology	Number of Determinations	Emission Limits
Selective Catalytic Reduction	1	0.025 lb/MMBtu
Low NOx Burners	8	0.05 – 0.06 lb/MMBtu 0.71 – 15.49 lb/hr
Good Combustion Practices & Proper Equipment Design	8	0.02 lb/MMBtu 0.09 – 29.41 lb/hr
No Control Specified	2	0.48 – 2.45 lb/hr

Step 1 – Identify NOx Control Technologies for the Thermal Oxidizer

From research, the Department identified the following technologies as available for NOx control of the flares and thermal oxidizer:

(a) Selective Catalytic Reduction (SCR)
The theory of SCR was discussed in detail in the NOx BACT Section 3.1 for the large simple cycle natural gas-fired combustion turbines and will not be repeated here. The Department's search of the RBLC database indicated that there is one thermal oxidizer equipped with SCR. Therefore, the Department considers SCR to be a technically feasible control technology for the thermal oxidizer.

(b) Low-NOx Burners (LNB)
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 LNBs a technically feasible control technology for the thermal oxidizer.

(c) Good Combustion Practices & Proper Equipment Design
The theory of GCPs was discussed in detail in CO BACT section 3.2 for the large simple cycle natural gas-fired combustion turbines and will not be repeated here. Proper equipment design includes designing a thermal oxidizer in order to maximize complete combustion of the gas stream being sent the EU, while also minimizing secondary emissions from the thermal oxidizer. Proper equipment design also includes designing the thermal oxidizer to meet the federal standards contained in 40 C.F.R. Subpart SS. The Department's search of the RBLC database indicated that GCPs and proper equipment design are commonly used to control emissions from thermal oxidizers. Therefore, the Department considers GCPs and proper equipment design to be a technically feasible control technology for the thermal oxidizer.

Step 2 – Eliminate Technically Infeasible NOx Control Options for the Thermal Oxidizer

All control technologies identified are technically feasible for thermal oxidizers.

Step 3 – Rank Remaining NOx Control Technologies for the Thermal Oxidizer
The following control technologies have been identified and ranked for control of NOx from the thermal oxidizer:

(a) SCR	(70% - 90% Control)
(b) Low NOx Burner	(40 - 60% Control)
(c) GCP & Proper Equipment Design	(<40% Control)

Step 4 – Evaluate the Most Effective Controls
RBLC Review
A review of similar units in the RBLC indicates that low NOx burners as well as good combustion practices and proper equipment design are the principle control methods for Particulate emissions from thermal oxidizers. There was one case in the RBLC of a thermal oxidizer equipped with a SCR. Environmental impacts from SCR include the disposal of the spent SCR catalyst when replacement becomes necessary, as well as ammonia slip from the SCR system.

Applicant Proposal
AGDC proposed to use good combustion practices and proper equipment design for the thermal oxidizer EU 13 as BACT for reducing NOx emissions. NOx emissions from EU 13 will not exceed 0.10 lb/MMBtu.

Department Evaluation of BACT for NOx emissions from Thermal Oxidizer
The Department notes that there is one example in the RBLC of a thermal oxidizer equipped with SCR. However, AGDC calculated NOx PTE for the thermal oxidizer at 2.6 tpy using an emission rate of 0.10 lb/MMBtu. The Department notes that an SCR system would not be cost effective for such a small amount of NOx emissions. However, there are eight examples in the RBLC of thermal oxidizers equipped with low NOx burners. These LNB equipped thermal oxidizers have an emission rate ranging from 0.05 – 0.06 lb/MMBtu. Therefore, the Department has determined that low NOx burners are relatively abundant on thermal oxidizers and should be considered proper equipment design on a newly constructed thermal oxidizer. The Department notes that requiring low NOx burners with an emission rate of 0.055 lb/MMBtu (the average from low NOx burner equipped thermal oxidizers in the RBLC) will give EU 13 a PTE of 1.4 tpy of NOx.

Step 5 – Selection of NOx BACT for the Thermal Oxidizer
The Department's finding is that BACT for NOx emissions from the thermal oxidizer is as follows:

(a) NOx emissions from EU 13 shall be minimized by good combustion practices and proper equipment design to include the installation of low NOx burners; and

(b) NOx emissions from EU 13 shall not exceed 0.055 lb/MMBtu averaged over a 3-hour period.

6.2 CO

Possible CO emission control technologies for the thermal oxidizer were obtained from the RBLC. The RBLC was searched for all processes containing the word thermal oxidizer. The search results were then filtered to include only emissions units with thermal oxidizers. The search results for the thermal oxidizer are summarized in Table 6-2.

Table 6-2. CO Controls for Thermal Oxidizers

Control Technology	Number of Determinations	Emission Limits
Oxidation Catalyst	1	1.5 ppmvd
Good Combustion Practices & Proper Equipment Design	13	0.08 – 0.11 lb/MMBtu 0.51 – 117.99 lb/hr
No Control Specified	2	1.2 – 91.85 lb/hr

Step 1 – Identify CO Control Technologies for the Thermal Oxidizer

From research, the Department identified the following technologies as available for CO control of the thermal oxidizer:

(a) Oxidation Catalyst
The theory of oxidation catalysts were discussed in detail in the CO BACT section 3.2 for the large simple cycle natural gas-fired combustion turbines. Oxidation catalysts oxidize CO and hydrocarbon compounds to carbon dioxide and water vapor. The reaction is spontaneous and no reactants are required. CO catalysts can achieve up to 90% reduction in CO emissions. The Department considers oxidation catalysts to be a technically feasible control technology for the thermal oxidizer.

(b) Good Combustion Practices & Proper Equipment Design
The theory of GCPs was discussed in detail in CO BACT section 3.2 for the large simple cycle natural gas-fired combustion turbines and will not be repeated here. Proper equipment design includes designing a thermal oxidizer in order to maximize complete combustion of the gas stream being sent the EU, while also minimizing secondary emissions from the thermal oxidizer. Proper equipment design also includes designing the thermal oxidizer to meet the federal standards contained in 40 C.F.R. Subpart SS. The Department's search of the RBLC database indicated that GCPs and proper equipment design are commonly used to control emissions from thermal oxidizers. Therefore, the Department considers GCPs and proper equipment design to be a technically feasible control technology for the thermal oxidizer.

Step 2 – Eliminate Technically Infeasible CO Control Options for the Thermal Oxidizer

All control technologies identified are technically feasible for thermal oxidizers.

Step 3 – Rank Remaining CO Control Technologies for the Thermal Oxidizer

The following control technologies have been identified and ranked for control of CO from the thermal oxidizer:

(a) Oxidation Catalyst (90% Control)
(b) GCP & Proper Equipment Design (Less than 90% Control)

Step 4 – Evaluate the Most Effective Controls
RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and proper equipment design are the principle control methods for CO emissions from thermal oxidizers. There was one case in the RBLC of a thermal oxidizer equipped with oxidation catalyst. Oxidation catalysts require no consumables and do not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary.

Applicant Proposal
AGDC proposed to use good combustion practices and proper equipment design for the thermal oxidizer EU 13 as BACT for reducing CO emissions. CO emissions from EU 13 will not exceed 0.082 lb/MMBtu.

Department Evaluation of BACT for CO emissions from Thermal Oxidizer
The Department notes that there is one example in the RBLC of a thermal oxidizer equipped with an oxidation catalyst. However, combined CO and VOC PTE for the thermal oxidizer is calculated at 2.31 tpy. The Department notes that an oxidation catalyst system would not be cost effective for such a small amount of CO and VOC emissions.

Step 5 – Selection of CO BACT for the Thermal Oxidizer
The Department's finding is that BACT for particulate emissions from the thermal oxidizer is as follows:

(a) CO emissions from EU 13 shall be minimized by good combustion practices and proper equipment design; and

(b) CO emissions from EU 13 shall not exceed 0.082 lb/MMBtu averaged over a 3-hour period (AP-42, Table 1.4-1, CO emission rate for natural gas combustion in external combustion sources, referenced in Texas Commission on Environmental Quality (TCEQ) NSR Emission Calculations for Vapor Oxidizers guidance document[12]).

6.3 Particulates
Possible particulate emission control technologies for the thermal oxidizer were obtained from the RBLC. The RBLC was searched for all processes containing the word thermal oxidizer. The search results were then filtered to include only emissions units with thermal oxidizers. The search results for the thermal oxidizer are summarized in Table 6-3.

Table 6-3. Particulate Controls for Thermal Oxidizers

Control Technology	Number of Determinations	Emission Limits
Good Combustion Practices, Clean Fuels & Proper Equipment Design	30	0.0075 – 0.016 lb/MMBtu 0.001 – 2.24 lb/hr
No Control Specified	2	0.1 – 0.3 lb/hr

Step 1 – Identify Particulate Control Technologies for the Thermal Oxidizer
From research, the Department identified the following technologies as available for particulate control of the thermal oxidizer:

[12] https://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/emiss_calc_vaporox.pdf.

(a) Good Combustion Practices, Clean Fuels, & Proper Equipment Design
The theory of GCP and clean fuels was discussed in detail in CO BACT section 3.2 for the large simple cycle natural gas-fired combustion turbines and will not be repeated here. Proper equipment design was discussed in detail in CO BACT section 6.2 for the thermal oxidizer and will not be repeated here. The Department's search of the RBLC database indicated that GCPs and proper equipment design are commonly used to control emissions from thermal oxidizers. Therefore, the Department considers GCPs and proper equipment design to be a technically feasible control technology for the thermal oxidizer.

Step 2 – Eliminate Technically Infeasible Particulate Control Options for the Thermal Oxidizer
All control technologies identified are technically feasible for thermal oxidizers.

Step 3 – Rank Remaining Particulate Control Technologies for the Thermal Oxidizer
AGDC has accepted the only technically feasible control options for the thermal oxidizer EU 13. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and proper equipment design are the principle control methods for particulate emissions from the thermal oxidizer. Since these are not add-on controls, there are no additional environmental impacts.

Applicant Proposal
AGDC proposed to use good combustion practices and proper equipment design for the thermal oxidizer EU 13 as BACT for reducing particulate emissions. Particulate emissions from EU 13 will not exceed 0.007 lb/MMBtu.

Step 5 – Selection of Particulate BACT for the Thermal Oxidizer
The Department's finding is that BACT for particulate emissions from the thermal oxidizer is as follows:

(a) Particulate emissions from EU 13 shall be minimized by good combustion practices and proper equipment design; and
(b) Particulate emissions from EU 13 shall not exceed 0.0075 lb/MMBtu averaged over a 3-hour period (AP-42, Table 1.4-2, PM (Total) emission rate for natural gas combustion in external combustion sources, referenced in TCEQ NSR Emission Calculations for Vapor Oxidizers guidance document[12]).

6.4 SO_2
Possible SO_2 emission control technologies for the thermal oxidizer were obtained from the RBLC. The RBLC was searched for all processes containing the word thermal oxidizer. The search results were then filtered to include only emissions units with thermal oxidizers. The search results for the thermal oxidizer are summarized in Table 6-4.

Table 6-4: SO_2 Controls for Thermal Oxidizer

Control Technology	Number of Determinations	Emission Limits

Good Combustion Practices, Clean Fuels & Proper Equipment Design	8	34 – 250 ppmv 0.001 – 15.1 lb/hr
No Control Specified	1	22.92 lb/hr

Step 1 – Identify SO_2 Control Technologies for the Thermal Oxidizer
From research, the Department identified the following technologies as available for SO_2 control of the flares:

(a) Good Combustion Practices, Clean Fuels, & Proper Equipment Design
The theory of GCP and clean fuels was discussed in detail in CO BACT section 3.2 for the large simple cycle natural gas-fired combustion turbines and will not be repeated here. Proper equipment design was discussed in detail in CO BACT section 6.2 for the thermal oxidizer and will not be repeated here. The Department's search of the RBLC database indicated that GCPs and proper equipment design are commonly used to control emissions from thermal oxidizers. Therefore, the Department considers GCPs and proper equipment design to be a technically feasible control technology for the thermal oxidizer.

Step 2 – Eliminate Technically Infeasible SO_2 Control Options for the Thermal Oxidizer
All control technologies identified are technically feasible for thermal oxidizers.

Step 3 – Rank Remaining SO_2 Control Technologies for the Thermal Oxidizer
AGDC has accepted the only technically feasible control options for the thermal oxidizer EU 13. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and proper equipment design are the principle control methods for SO_2 emissions from the thermal oxidizer. Since these are not add-on controls, there are no additional environmental impacts.

Applicant Proposal
AGDC proposed to use good combustion practices and proper equipment design for the thermal oxidizer EU 13 as BACT for reducing SO_2 emissions. AGDC will utilize only natural gas condensate in the thermal oxidizer EU 13 with a total sulfur content not to exceed 16 ppmv.

Step 5 – Selection of SO_2 BACT for the Thermal Oxidizer
The Department's finding is that BACT for SO_2 emissions from the thermal oxidizer is as follows:

(a) SO_2 emissions from EU 13 shall be minimized by good combustion practices and proper equipment design, and by burning natural gas condensate with a total sulfur content not to exceed 16 ppmv; and

(b) Compliance with the proposed fuel sulfur content limit will be demonstrated with fuel shipment receipts and/or fuel test results for total sulfur content.

6.5 VOC

Possible VOC emission control technologies for the thermal oxidizer were obtained from the RBLC. The RBLC was searched for all processes containing the word thermal oxidizer. The search results were then filtered to include only emissions units with thermal oxidizers. The search results for the thermal oxidizer are summarized in Table 6-5.

Table 6-5: VOC Controls for Thermal Oxidizer

Control Technology	Number of Determinations	Emission Limits
Oxidation Catalyst	1	0.03 lb/hr
Good Combustion Practices, Clean Fuels & Proper Equipment Design	11	0.03 – 442.25 lb/hr 10 ppmv 0.005 lb/MMBtu

Step 1 – Identify VOC Control Technologies for the Thermal Oxidizer

From research, the Department identified the following technologies as available for VOC control of the thermal oxidizers:

(a) Oxidation Catalyst
Oxidation catalyst can control VOC emissions in the exhaust gas with the proper selection of catalyst. The oxidation reaction is spontaneous and does not require addition reagents. Formaldehyde and other organic HAPs can see reductions of 85% to 90%. The Department considers oxidation catalysts to be a technically feasible control technology for the thermal oxidizer.

(b) Good Combustion Practices & Proper Equipment Design
The theory of GCPs was discussed in detail in CO BACT section 3.2 for the large simple cycle natural gas-fired combustion turbines and will not be repeated here. Proper equipment design includes designing a thermal oxidizer in order to maximize complete combustion of the gas stream being sent the EU, while also minimizing secondary emissions from the thermal oxidizer. Proper equipment design also includes designing the thermal oxidizer to meet the federal standards contained in 40 C.F.R. Subpart SS. The Department's search of the RBLC database indicated that GCPs and proper equipment design are commonly used to control emissions from thermal oxidizers. Therefore, the Department considers GCPs and proper equipment design to be a technically feasible control technology for the thermal oxidizer.

Step 2 – Eliminate Technically Infeasible VOC Control Options for the Thermal Oxidizer

All control technologies identified are technically feasible for thermal oxidizers.

Step 3 – Rank Remaining VOC Control Technologies for the Thermal Oxidizer

The following control technologies have been identified and ranked for control of VOC from the thermal oxidizer:

(a) Oxidation Catalyst (85% to 90% Control)
(b) GCP & Proper Equipment Design (Less than 85% Control)

Step 4 – Evaluate the Most Effective Controls

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and proper equipment design are the principle control methods for VOC emissions from thermal oxidizers. There was one case in the RBLC of a thermal oxidizer equipped with oxidation catalyst. Oxidation catalysts require no consumables and do not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary.

Applicant Proposal
AGDC proposed to use good combustion practices and proper equipment design for the thermal oxidizer EU 13 as BACT for reducing VOC emissions. VOC emissions from EU 13 will not exceed 0.005 lb/MMBtu.

Department Evaluation of BACT for VOC emissions from Thermal Oxidizer
The Department notes that there is one example in the RBLC of a thermal oxidizer equipped with an oxidation catalyst. However, combined CO and VOC PTE for the thermal oxidizer is calculated at 2.31 tpy. The Department notes that an oxidation catalyst system would not be cost effective for such a small amount of CO and VOC emissions.

Step 5 – Selection of VOC BACT for the Thermal Oxidizer
The Department's finding is that BACT for VOC emissions from the thermal oxidizer is as follows:

(a) VOC emissions from EU 13 shall be minimized by good combustion practices and proper equipment design; and
(b) VOC emissions from EU 13 shall not exceed 0.0054 lb/MMBtu averaged over a 3-hour period (AP-42, Table 1.4-2, VOC emission rate for natural gas combustion in external combustion sources, referenced in TCEQ NSR Emission Calculations for Vapor Oxidizers guidance document[12]).

6.6 GHG
Possible GHG emission control technologies for the thermal oxidizer were obtained from the RBLC. The RBLC was searched for all processes containing the word thermal oxidizer. The search results were then filtered to include only emissions units with thermal oxidizers. The search results for the thermal oxidizer are summarized in Table 6-6.

Table 6-6. GHG Controls for Thermal Oxidizers

Control Technology	Number of Determinations	Emission Limits
Good Combustion Practices, Clean Fuels & Proper Equipment Design	11	117 lb/MMBtu 236 – 374,114 tpy
No Control Specified	4	36,406 – 215,192 tpy

Step 1 – Identify GHG Control Technologies for the Thermal Oxidizer
From research, the Department identified the following technologies as available for GHG control of the thermal oxidizer:

(a) Good Combustion Practices, Clean Fuels, & Proper Equipment Design
The theory of GCP and clean fuels was discussed in detail in CO BACT section 3.2 for the large simple cycle natural gas-fired combustion turbines and will not be repeated here. Proper equipment design was discussed in detail in CO BACT section 6.2 for the thermal oxidizer and will not be repeated here. The Department's search of the RBLC database indicated that GCPs and proper equipment design are commonly used to control emissions from thermal oxidizers. Therefore, the Department considers GCPs and proper equipment design to be a technically feasible control technology for the thermal oxidizer.

Step 2 – Eliminate Technically Infeasible GHG Control Options for the Thermal Oxidizer
All control technologies identified are technically feasible for thermal oxidizers.

Step 3 – Rank Remaining GHG Control Technologies for the Thermal Oxidizer
AGDC has accepted the only technically feasible control options for the thermal oxidizer EU 13. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and proper equipment design are the principle control methods for Particulate emissions from the thermal oxidizer. Since these are not add-on controls, there are no additional environmental impacts.

Applicant Proposal
AGDC proposed to use good combustion practices and proper equipment design for the thermal oxidizer EU 13 as BACT for reducing GHG emissions. GHG emissions from EU 13 will not exceed 117.1 lb/MMBtu, which is the CO_2e emissions rates for burning natural gas in 40 CFR Part 98: Mandatory Greenhouse Gas Reporting. The total CO_2e emissions rate is calculated with the equation $CO_2(1) + CH_4(25) + N_2O(298)$.

Step 5 – Selection of GHG BACT for the Thermal Oxidizer
The Department's finding is that BACT for GHG emissions from the thermal oxidizer is as follows:

(a) GHG emissions from EU 13 shall be minimized by good combustion practices and proper equipment design; and

(b) GHG emissions from EU 13 shall not exceed 117.1 lb/MMBtu averaged over a 3-hour period.

7.0 VENT GAS DISPOSAL (FLARES)

The Liquefaction Plant will utilize three flare gas systems (i.e., wet, dry, and low-pressure, EUs 14 - 20) to route relief vapors from separate sections of the plant into their respective flare collection headers. The wet flare gas system (EUs 15, 17, and 19) will control waste gas streams containing a significant concentration of water and heavier compounds. The dry flare gas system (EUs 14, 16, and 18) will be used for safe disposal of dry hydrocarbons streams discharged downstream of the dehydration unit. The low-pressure BOG flare gas system (EU 20) will be used for safe disposal of the low-pressure operational release from the LNG storage and loading system and intermittent maintenance purging of inert gas from LNG carriers. These flare systems prevent the direct relief to the atmosphere of vent gases that contain VOC and GHG (in the form of CH_4). The flares will emit CO, NOx, SO_2, particulates, VOC, and GHG. The following sections provide the BACT review for each of these pollutants.

7.1 NOx

Possible NOx emission control technologies for the flares were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 19: Miscellaneous combustion (19:300 is specific to flares) and 50: Petroleum/Natural Gas Production and Refining. The search results were then filtered to include only emissions units with flares. The search results for the flares are summarized in Table 7-1.

Table 7-1: NOx Controls for Flares

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Flare Work Practice Requirements	7	0.02 - 0.098
Flaring Minimization Plan	10	0.068
No Control Specified	8	0.05 - 0.068

Step 1 – Identify NOx Control Technologies for the Flares

From research, the Department identified the following technologies as available for NOx control of the flares:

(a) Flare Work Practice Requirements
Flare work practice requirements can be found in 40 CFR 60.18 (c) through (f). Flare design and monitoring are key elements in emissions performance of flares. Flares must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The Department considers proper flare design and good combustion practices as technically feasible control options for the flares.

(b) Flaring Minimization Plan
Flaring minimization plans define the procedures intended to reduce the frequency, magnitude, and duration of flaring events, without compromising plant operations or safety. By limiting the volume of gas going to the flare, all emissions types are minimized. The Department considers flaring minimization plans a technically feasible control options for the flares.

(c) Flare Gas Recovery
Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams, such as petroleum refineries, to reduce gaseous emissions to the atmosphere by recovering waste gas to be reused in the production process. However, flare gas recovery is not part of the Liquefaction Plant flare system design, as there would be no routine and continuous venting of gas to the flare. Therefore, consideration of flare gas recovery is unnecessary as a potential control technology.

Step 2 – Eliminate Technically Infeasible NOx Control Options for the Flares

As explained in Step 1, flare gas recovery is not feasible to control NOx emissions from the flares.

Step 3 – Rank Remaining NOx Control Technologies for the Flares
AGDC has accepted the remaining two technically feasible control options for the flares EUs 14 – 20. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
RBLC Review
A review of similar units in the RBLC indicates that use of flare work practice requirements (including proper flare design and good combustion practices) as well as a flaring minimization plan are the principle control methods for NOx emissions from flares. Since these are not add-on controls, there are no additional environmental impacts.

Applicant Proposal
AGDC proposed to use good combustion practices, proper flare design, and create a flaring minimization plan for the flares EUs 14 – 20 as BACT for reducing NOx emissions. Additionally, the wet and dry flares EUs 14 – 19 will be limited to 500 hours of flaring per 12-month rolling period per flare and the low pressure flare EU 20 will be limited to 144 hours of flaring per 12-month rolling period. NOx emissions from EUs 14 – 20 will not exceed 0.068 lb/MMBtu.

Step 5 – Selection of NOx BACT for the Flares
The Department's finding is that BACT for NOx emissions from the flares is as follows:

(a) NOx emissions from EUs 14 – 20 shall be minimized by proper flare work practice requirements and establishing a flaring minimization plan;

(b) Limit the number of hours EUs 14 through 19 flare during startup, shutdown, and maintenance events, to no more than 500 hours per 12 consecutive month period per flare;[13]

(c) Limit the number of hours EU 20 flares during startup, shutdown, and maintenance events, to no more than 144 hours per 12 consecutive month period; [14] and

(d) NOx emissions from EUs 14 – 20 shall not exceed 0.068 lb/MMBtu averaged over a 3-hour period (AP-42 Table 13.5-1, NOx emissions rate for flare operations).

7.2 CO
Possible CO emission control technologies for the flares were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 19: Miscellaneous combustion (19:300 is specific to flares) and 50: Petroleum/Natural Gas Production and Refining. The search results were then filtered to include only emissions units with flares. The search results are summarized in Table 7-2.

Table 7-2. CO Controls for Flares

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Flare Work Practice Requirements	7	0.08 - 0.37
Flaring Minimization Plan	12	0.31 – 0.37

[13] This 500 hour flaring limit does not include pilot and purge, emergency, or process upset flaring.
[14] This 144 hour flaring limit does not include pilot and purge, emergency, or process upset flaring.

No Control Specified	6	0.082 – 0.37

Step 1 – Identify CO Control Technologies for the Flares
From research, the Department identified the following technologies as available for CO control of the flares:

(a) Flare Work Practice Requirements
Flare work practice requirements can be found in 40 CFR 60.18 (c) through (f). Flare design and monitoring are key elements in emissions performance of flares. Flares must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The Department considers proper flare design and good combustion practices as technically feasible control options for the flares.

(b) Flaring Minimization Plan
Flaring minimization plans define the procedures intended to reduce the frequency, magnitude, and duration of flaring events, without compromising plant operations or safety. By limiting the volume of gas going to the flare, all emissions types are minimized. The Department considers flaring minimization plans a technically feasible control options for the flares.

(c) Flare Gas Recovery
Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams, such as petroleum refineries, to reduce gaseous emissions to the atmosphere by recovering waste gas to be reused in the production process. However, flare gas recovery is not part of the Liquefaction Plant flare system design, as there would be no routine and continuous venting of gas to the flare. Therefore, consideration of flare gas recovery is unnecessary as a potential control technology.

Step 2 – Eliminate Technically Infeasible CO Control Options for the Flares
As explained in Step 1, flare gas recovery is not feasible to control CO emissions from the flares.

Step 3 – Rank Remaining CO Control Technologies for the Flares
AGDC has accepted the remaining two technically feasible control options for the flares EUs 14 – 20. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
RBLC Review
A review of similar units in the RBLC indicates that use of flare work practice requirements (including proper flare design and good combustion practices) as well as a flaring minimization plan are the principle control methods for CO emissions from flares. Since these are not add-on controls, there are no additional environmental impacts.

Applicant Proposal
AGDC proposed to use good combustion practices, proper flare design, and create a flaring minimization plan for the flares EUs 14 – 20 as BACT for reducing CO emissions. Additionally, the wet and dry flares EUs 14 – 19 will be limited to 500 hours of flaring per 12-month rolling

period per flare and the low pressure flare EU 20 will be limited to 144 hours of flaring per 12-month rolling period. CO emissions from EUs 14 – 20 will not exceed 0.31 lb/MMBtu.

Step 5 – Selection of CO BACT for the Flares
The Department's finding is that BACT for CO emissions from the flares is as follows:

(a) CO emissions from EUs 14 – 20 shall be minimized by proper flare work practice requirements and establishing a flaring minimization plan;

(b) Limit the number of hours EUs 14 through 19 flare during startup, shutdown, and maintenance events, to no more than 500 hours per 12 consecutive month period per flare;[13]

(c) Limit the number of hours EU 20 flares during startup, shutdown, and maintenance events, to no more than 144 hours per 12 consecutive month period;[14] and

(d) CO emissions from EUs 14 – 20 shall not exceed 0.31 lb/MMBtu averaged over a 3-hour period (AP-42 Table 13.5-2, CO emissions rate for flare operations).

7.3 Particulates

Possible particulate emission control technologies for the flares were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 19: Miscellaneous combustion (19:300 is specific to flares) and 50: Petroleum/Natural Gas Production and Refining. The search results were then filtered to include only emissions units with flares. The search results are summarized in Table 7-3.

Table 7-3: Particulate Controls for Flares

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Flare Work Practice Requirements	10	0.007 – 0.016
Flaring Minimization Plan	25	0.0019 – 0.0075
No Control Specified	9	0.0019 – 0.0264

Step 1 – Identify Particulate Control Technologies for the Flares
From research, the Department identified the following technologies as available for particulate control of the flares:

(a) Flare Work Practice Requirements
Flare work practice requirements can be found in 40 CFR 60.18 (c) through (f). Flare design and monitoring are key elements in emissions performance of flares. Flares must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The Department considers proper flare design and good combustion practices as technically feasible control options for the flares.

(b) Flaring Minimization Plan
Flaring minimization plans define the procedures intended to reduce the frequency, magnitude, and duration of flaring events, without compromising plant operations or safety. By limiting the volume of gas going to the flare, all emissions types are

minimized. The Department considers flaring minimization plans a technically feasible control options for the flares.

(c) Flare Gas Recovery
Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams, such as petroleum refineries, to reduce gaseous emissions to the atmosphere by recovering waste gas to be reused in the production process. However, flare gas recovery is not part of the Liquefaction Plant flare system design, as there would be no routine and continuous venting of gas to the flare. Therefore, consideration of flare gas recovery is unnecessary as a potential control technology.

Step 2 – Eliminate Technically Infeasible Particulate Control Options for the Flares
As explained in Step 1, flare gas recovery is not feasible to control particulate emissions from the flares.

Step 3 – Rank Remaining Particulate Control Technologies for the Flares
AGDC has accepted the remaining two technically feasible control options for the flares EUs 14 – 20. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
RBLC Review
A review of similar units in the RBLC indicates that use of flare work practice requirements (including proper flare design and good combustion practices) as well as a flaring minimization plan are the principle control methods for Particulate emissions from flares. Since these are not add-on controls, there are no additional environmental impacts.

Applicant Proposal
AGDC proposed to use good combustion practices, proper flare design, and create a flaring minimization plan for the flares EUs 14 – 20 as BACT for reducing particulate emissions. Additionally, the wet and dry flares EUs 14 – 19 will be limited to 500 hours of flaring per 12-month rolling period per flare and the low pressure flare EU 20 will be limited to 144 hours of flaring per 12-month rolling period. Particulate emissions from EUs 14 – 20 will not exceed 40 µg/L (equivalent to 0.028 lb/MMBtu).

Step 5 – Selection of Particulate BACT for the Flares
The Department's finding is that BACT for particulate emissions from the flares is as follows:

(a) Particulate emissions from EUs 14 – 20 shall be minimized by proper flare work practice requirements and establishing a flaring minimization plan;

(b) Limit the number of hours EUs 14 through 19 flare during startup, shutdown, and maintenance events, to no more than 500 hours per 12 consecutive month period per flare;[13]

(c) Limit the number of hours EU 20 flares during startup, shutdown, and maintenance events, to no more than 144 hours per 12 consecutive month period;[14] and

(d) Particulate emissions from EUs 14 – 20 shall not exceed 40 µg/L (0.028 lb/MMBtu) averaged over a 3-hour period (AP-42 Table 13.5-1, particulate emissions rate for lightly smoking flares).

7.4 SO_2

Possible SO_2 emission control technologies for the flares were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 19: Miscellaneous combustion (19:300 is specific to flares) and 50: Petroleum/Natural Gas Production and Refining. The search results were then filtered to include only emissions units with flares. The search results are summarized in Table 7-4.

Table 7-4: SO_2 Controls for Flares

Control Technology	Number of Determinations	Emission Limits
Flare Work Practice Requirements	3	0.0001 – 0.0008 lb/hr
Flaring Minimization Plan	1	13,023.6 lb/hr
GCP & Clean Fuel	3	34 – 1,000 ppmv H_2S in fuel
No Control Specified	4	0.01 – 1,303.99 lb/hr

Step 1 – Identify SO_2 Control Technologies for the Flares

From research, the Department identified the following technologies as available for SO_2 control of the flares:

(a) Flare Work Practice Requirements
Flare work practice requirements can be found in 40 CFR 60.18 (c) through (f). Flare design and monitoring are key elements in emissions performance of flares. Flares must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The Department considers proper flare design and good combustion practices as technically feasible control options for the flares.

(b) Flaring Minimization Plan
Flaring minimization plans define the procedures intended to reduce the frequency, magnitude, and duration of flaring events, without compromising plant operations or safety. By limiting the volume of gas going to the flare, all emissions types are minimized. The Department considers flaring minimization plans a technically feasible control options for the flares.

(c) Flare Gas Recovery
Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams, such as petroleum refineries, to reduce gaseous emissions to the atmosphere by recovering waste gas to be reused in the production process. However, flare gas recovery is not part of the Liquefaction Plant flare system design, as there would be no routine and continuous venting of gas to the flare. Therefore, consideration of flare gas recovery is unnecessary as a potential control technology.

(d) Good Combustion Practices (GCP) and Clean Fuels
As discussed in detail in CO BACT Section 4.2, as well as the fuel specifications portion of particulate BACT Section 4.3, GCP and clean fuels is a common technique for controlling SO_2 emissions. SO_2 emissions in the exhaust of flares are directly related to the levels of sulfur in the fuel. As such, fuel specifications are a primary method of SO_2 emissions control and are a feasible control technology for the flares.

Step 2 – Eliminate Technically Infeasible SO_2 Control Options for the Flares
As explained in Step 1, flare gas recovery is not feasible to control SO_2 emissions from the flares.

Step 3 – Rank Remaining SO_2 Control Technologies for the Flares
AGDC has accepted the remaining three technically feasible control options for the flares EUs 14 – 20. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
RBLC Review
A review of similar units in the RBLC indicates that use of flare work practice requirements (including proper flare design and good combustion practices) as well as a flaring minimization plan are the principle control methods for SO_2 emissions from flares. Since these are not add-on controls, there are no additional environmental impacts.

Applicant Proposal
AGDC proposed to use good combustion practices, proper flare design, and create a flaring minimization plan for the flares EUs 14 – 20 as BACT for reducing SO_2 emissions. Additionally, the wet and dry flares EUs 14 – 19 will be limited to 500 hours of flaring per 12-month rolling period per flare and the low pressure flare EU 20 will be limited to 144 hours of flaring per 12-month rolling period. AGDC will utilize only natural gas in the flares EUs 14 – 20 with a total sulfur content not to exceed 16 ppmv.

Step 5 – Selection of SO_2 BACT for the Flares
The Department's finding is that BACT for SO_2 emissions from the flares is as follows:

(a) SO_2 emissions from EUs 14 – 20 shall be minimized by burning natural gas with a total sulfur content not to exceed 16 ppmv, following proper flare work practice requirements and establishing a flaring minimization plan;
(b) Limit the number of hours EUs 14 through 19 flare during startup, shutdown, and maintenance events, to no more than 500 hours per 12 consecutive month period per flare;[13]
(c) Limit the number of hours EU 20 flares during startup, shutdown, and maintenance events, to no more than 144 hours per 12 consecutive month period;[14] and
(d) Compliance with the proposed fuel sulfur content limit will be demonstrated with fuel shipment receipts and/or fuel test results for total sulfur content.

7.5 VOC
Possible VOC emission control technologies for the flares were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 19: Miscellaneous combustion (19:300 is specific to flares) and 50: Petroleum/Natural Gas Production and Refining. The search results were then filtered to include only emissions units with flares. The search results are summarized in Table 7-5.

Table 7-5: VOC Controls for Flares

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Flare Work Practice Requirements	4	0.0054
Flaring Minimization Plan	9	0.0054
No Control Specified	4	0.0054 – 0.14

Step 1 – Identify VOC Control Technologies for the Flares
From research, the Department identified the following technologies as available for VOC control of the flares:

(a) Flare Work Practice Requirements
Flare work practice requirements can be found in 40 CFR 60.18 (c) through (f). Flare design and monitoring are key elements in emissions performance of flares. Flares must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The Department considers proper flare design and good combustion practices as technically feasible control options for the flares.

(b) Flaring Minimization Plan
Flaring minimization plans define the procedures intended to reduce the frequency, magnitude, and duration of flaring events, without compromising plant operations or safety. By limiting the volume of gas going to the flare, all emissions types are minimized. The Department considers flaring minimization plans a technically feasible control options for the flares.

(c) Flare Gas Recovery
Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams, such as petroleum refineries, to reduce gaseous emissions to the atmosphere by recovering waste gas to be reused in the production process. However, flare gas recovery is not part of the Liquefaction Plant flare system design, as there would be no routine and continuous venting of gas to the flare. Therefore, consideration of flare gas recovery is unnecessary as a potential control technology.

Step 2 – Eliminate Technically Infeasible VOC Control Options for the Flares
As explained in Step 1, flare gas recovery is not feasible to control VOC emissions from flares.

Step 3 – Rank Remaining VOC Control Technologies for the Flares
AGDC has accepted the remaining two technically feasible control options for the flares EUs 14 – 20. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
RBLC Review
A review of similar units in the RBLC indicates that use of flare work practice requirements (including proper flare design and good combustion practices) as well as a flaring minimization plan are the principle control methods for VOC emissions from flares. Since these are not add-on controls, there are no additional environmental impacts.

Applicant Proposal

AGDC proposed to use good combustion practices, proper flare design, and create a flaring minimization plan for the flares EUs 14 – 20 as BACT for reducing VOC emissions. Additionally, the wet and dry flares EUs 14 – 19 will be limited to 500 hours of flaring per 12-month rolling period per flare and the low pressure flare EU 20 will be limited to 144 hours of flaring per 12-month rolling period. VOC emissions from EUs 14 – 20 will not exceed 0.57 lb/MMBtu.

Step 5 – Selection of VOC BACT for the Flares
The Department's finding is that BACT for VOC emissions from the flares is as follows:

(a) VOC emissions from EUs 14 – 20 shall be minimized by proper flare work practice requirements and establishing a flaring minimization plan;

(b) Limit the number of hours EUs 14 through 19 flare during startup, shutdown, and maintenance events, to no more than 500 hours per 12 consecutive month period per flare;[13]

(c) Limit the number of hours EU 20 flares during startup, shutdown, and maintenance events, to no more than 144 hours per 12 consecutive month period;[14] and

(d) VOC emissions from EUs 14 – 20 shall not exceed 0.66 lb/MMBtu averaged over a 3-hour period (AP-42 Table 13.5-2, VOC emissions rate for flare operations).

7.6 GHG
Possible GHG emission control technologies for the flares were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 19: Miscellaneous combustion (19:300 is specific to flares) and 50: Petroleum/Natural Gas Production and Refining. The search results were then filtered to include only emissions units with flares. The search results are summarized in Table 7-6.

Table 7-6: GHG Controls for Flares

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Flare Work Practice Requirements & Flaring Minimization Plan	11	116.89 – 117
No Control Specified	2	116.89

Step 1 – Identify GHG Control Technologies for the Flares
From research, the Department identified the following technologies as available for GHG control of the flares:

(a) Flare Work Practice Requirements
Flare work practice requirements can be found in 40 CFR 60.18 (c) through (f). Flare design and monitoring are key elements in emissions performance of flares. Flares must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The Department considers proper flare design and good combustion practices as technically feasible control options for the flares.

(b) Flaring Minimization Plan
Flaring minimization plans define the procedures intended to reduce the frequency, magnitude, and duration of flaring events, without compromising plant operations or safety. By limiting the volume of gas going to the flare, all emissions types are minimized. The Department considers flaring minimization plans a technically feasible control options for the flares.

(c) Flare Gas Recovery
Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams, such as petroleum refineries, to reduce gaseous emissions to the atmosphere by recovering waste gas to be reused in the production process. However, flare gas recovery is not part of the Liquefaction Plant flare system design, as there would be no routine and continuous venting of gas to the flare. Therefore, consideration of flare gas recovery is unnecessary as a potential control technology.

Step 2 – Eliminate Technically Infeasible GHG Control Options for the Flares
As explained in Step 1, flare gas recovery is not feasible to control GHG emissions from the flares.

Step 3 – Rank Remaining GHG Control Technologies for the Flares
AGDC has accepted the remaining two technically feasible control options for the flares EUs 14 – 20. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
RBLC Review
A review of similar units in the RBLC indicates that use of flare work practice requirements (including proper flare design and good combustion practices) as well as a flaring minimization plan are the principle control methods for GHG emissions from flares. Since these are not add-on controls, there are no additional environmental impacts.

Applicant Proposal
AGDC proposed to use good combustion practices, proper flare design, and create a flaring minimization plan for the flares EUs 14 – 20 as BACT for reducing GHG emissions. Additionally, the wet and dry flares EUs 14 – 19 will be limited to 500 hours of flaring per 12-month rolling period per flare and the low pressure flare EU 20 will be limited to 144 hours of flaring per 12-month rolling period. GHG emissions from EUs 14 – 20 will not exceed 117.1 lb/MMBtu, which is the CO_2e emissions rates for burning natural gas in 40 CFR Part 98: Mandatory Greenhouse Gas Reporting. The total CO_2e emissions rate is calculated with the equation $CO_2(1) + CH_4(25) + N_2O(298)$.

Step 5 – Selection of GHG BACT for the Flares
The Department's finding is that BACT for GHG emissions from the flares is as follows:

(a) GHG emissions from EUs 14 – 20 shall be minimized by proper flare work practice requirements and establishing a flaring minimization plan;

(b) Limit the number of hours EUs 14 through 19 flare during startup, shutdown, and maintenance events, to no more than 500 hours per 12 consecutive month period per flare;[13]

(c) Limit the number of hours EU 20 flares during startup, shutdown, and maintenance events, to no more than 144 hours per 12 consecutive month period;[14] and

(d) GHG emissions from EUs 14 – 20 shall not exceed 117.1 lb/MMBtu averaged over a 3-hour period.

8.0 FUEL TANKS

The Liquefaction Plant will have a total of two gas condensate storage tanks (EUs 21 and 22), a loading system for the gas condensates (EU 23) for transporting the condensate offsite for sales, and three diesel fuel tanks (EUs 24 – 26). EU 21 will hold 457,890 gallons of gas condensate and EU 22 will hold 126,904 gallons of gas condensate. EU 24 will hold 3,520 gallons of diesel fuel, and both EUs 25 and 26 will hold 342 gallons of diesel fuel each. These diesel fuel tanks will be used to supply fuel to the diesel EUs at the facility as well as support equipment and vehicles. The fuel tanks will emit VOCs. The following section provides the BACT review for VOC.

8.1 VOC

Possible VOC emission control technologies for the fuel tanks were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 42.005 Petroleum Liquid Storage in Fixed Roof Tanks and 42.006 Petroleum Liquid Storage in Floating Roof Tanks. The search results are summarized in Table 8-1.

Table 8-1. VOC Control for Fuel Tanks

Control Technology	Number of Determinations	Emission Limits (tpy)
Floating Roof	30	0.88 - 18.57
Submerged Fill	7	0.8 - 72.5
Fixed Roof	5	0.8 - 72.5
Vapor Recovery System	4	3.95 - 7.33
NSPS	3	114.1
Leak Detection and Repair	1	28.3
No Control Specified	15	0.05 - 81.57

Step 1 – Identify VOC Control Technologies for Fuel Tanks

From research, the Department identified the following technologies as available for VOC control of the fuel tanks:

(a) Floating Roof
Floating roof tanks contain a roof that floats on the surface of the liquid that will rise and fall with the liquid level in the level in the tank, creating no vapor space except for when tanks have low liquid levels. External floating roof tanks are designed with a roof consisting of a double deck or pontoon single deck which rests or floats on the liquid being contained. An internal floating roof includes a fixed roof over the floating roof, to protect the floating roof from damage and deterioration. In general, the floating roof covers the entire liquid surface except for a small perimeter rim space. Under normal

floating conditions, the roof floats essentially flat and is centered within the tank shell. The floating roof must be designed with perimeter seals (primary and secondary seals) which slide against the tank wall as the roof moves up and down. The use of perimeter seals minimizes emissions of VOCs from the tank. Sources of emissions from floating roof tanks include standing storage loss and withdrawal losses. Standing losses occur due to improper fits between tank seal and the tank shell. Withdrawal losses occur when liquid is removed from the tank, lowering the floating roof, revealing a liquid on the tank walls which vaporize. The Department considers floating roof tanks as a technically feasible control option for fuel tanks.

(b) Flare or Thermal Oxidizer
Enclosed flares combust the vent gases inside of the stack, avoiding the aesthetic concerns that can accompany visible flames produced by open flares. More burner tips are provided than for the open flare and the burner tips are located low enough inside the stack that there is no visible flame outside the stack. Air is drawn in through an adjustable opening in the bottom of the flare stack. A continuously lit pilot ensures that vent gases are combusted at the flare tip. A properly operated flare can achieve a destruction efficiency of 98 percent or greater. The Department considers a flare of thermal oxidizer as a technically feasible control option for fuel tanks.

(c) Submerged Fill
Submerged filling involves filling a tank through an opening underneath the liquid surface level (pipe opening usually 12" or less from bottom of tank) in order to minimize the production of vapors. The use of submerged fill during tank loading operations can reduce vaporization of the liquid between 40 – 60% from traditional splash loading operations. Note that the use of submerged fill is a control technique specific to the filling of a tank and does not affect the day-to-day emissions of the tank. The Department considers submerged fill as a technically feasible control option for the fuel tanks.

(d) Vapor Recovery System
A vapor recovery system (VRS) can be used to draw vapors out of the storage tank, which are routed through a compressor. Compressed vapors may be used onsite as fuel for combustion units or routed to sales gas compressors for further compression to pipeline specifications. VRSs can recover over 95% of the hydrocarbon emissions that accumulate in the storage tanks.

(e) Leak Detection and Repair
A system of detecting tank leaks for repairs. This can range from a visual inspection to a computerized system with in-tank probes.

Step 2 – Eliminate Technically Infeasible VOC Control Options for Fuel Tanks
The largest of the diesel fuel tanks at the Liquefaction Plant is 3,520 gallons and is expected to be horizontal, square or rectangular in shape. This design is not conducive to a floating roof, which are found in larger round fuel tanks (greater than 20,000 gallons). While the condensate storage tanks are large in design, the vapor pressure of condensate can be quite high (i.e. exceed 11 psia) under certain temperature conditions. This highly volatile liquid would compromise the

integrity of the seal systems on internal and external floating roof tanks. Therefore, a floating roof control system is eliminated from further consideration for both the diesel and condensate tanks.

Step 3 – Rank Remaining VOC Control Options for Fuel Tanks
The following control technologies have been identified and ranked for control of VOC from the tanks:

(a) Flare/Thermal Oxidizer (98% Control)
(b) Vapor Recovery System (95% Control)
(c) Submerged Fill (40%-60% Control)
(d) Leak Detection and Repair (40% Control)

Step 4 – Evaluate the Most Effective Controls
A flare/thermal oxidizer and vapor recovery systems are the most effective control technologies for the fuel tanks at the Liquefaction Plant. Flare/thermal oxidizer systems require combustion of the gas stream from the fuel tanks, which will limit VOC emissions at the expense of creating other criteria pollutants. Separately, submerged fill has the best VOC emissions control without requiring an add-on control, other than proper tank design.

RBLC Review
A review of similar units in the RBLC indicates add-on control technology is not practical for small diesel tanks such as those contained at the Liquefaction Plant. Based on the small potential to emit of less than 0.01 tpy of VOCs for all three diesel tanks combined, add on controls are not a cost effective control technology for the diesel tanks at the Liquefaction Plant.

Applicant Proposal
AGDC proposes the following as BACT for VOC emissions from the fuel tanks:

(a) VOC emissions from the operation of the condensate tanks EUs 21 and 22 and associated loading system EU 23will be controlled with the use of capture and recovery through a vapor balance system and combustion of vapors in a thermal oxidizer (EU 13);
(b) VOC emissions from the operation of the diesel fuel tanks EUs 24 – 26 will be controlled with the use of submerged fill; and
(c) VOC emissions from the diesel fuel tanks EUs 24 – 26 will not exceed 0.01 tons per year.

Department Evaluation of BACT for VOC Emissions from Fuel Tank
The Department agrees with AGDC that add on controls are not cost effective for diesel tanks with combined potential to emit for VOC emissions of less than 0.01 tpy.

Step 5 – Selection of VOC BACT for Fuel Tanks
The Department's finding is that BACT for VOC emissions from the fuel tanks is as follows:

(a) VOC emissions from the operation of the condensate tanks EUs 21 and 22 and associated loading system EU 23 will be controlled with the use of capture and recovery through a vapor balance system and combustion of vapors in a thermal oxidizer (EU 13), at all times the units are operating;

(b) VOC emissions from the operation of the diesel fuel tanks EUs 24 – 26 will be controlled with the use of submerged fill; and

(c) VOC emissions from the diesel fuel tanks EUs 24 – 26 will not exceed 0.01 tons per year combined.

Appendix C: BACT Summary

Table C-1. NOx BACT Limits

EU ID	Description	BACT Limit	BACT Control
1 – 6	1,113 MMBtu/hr Simple Cycle Treated Gas Compressor Turbines	9 ppmvd at 15% O_2	Dry Low NOx; Good Combustion Practices
7 – 10	384 MMBtu/hr Combined Cycle Power Generation Combustion Turbines	9 ppmvd at 15% O_2	Dry Low NOx; Good Combustion Practices
11	575 hp Firewater Pump Engine (ULSD)	3.6 g/hp-hr	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
12	300 hp Auxiliary Air Compressor Engine (ULSD)	0.45 g/hp-hr	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
13	Vent Gas Disposal (Thermal Oxidizer) 6.0 MMBtu/hr	0.055 lb/MMBtu	Low NOx Burners; Proper Equipment Design; Good Combustion Practices
14 – 20	Vent Gas Disposal (Flares) 2.1 – 55,000 Mscf/hr	0.068 lb/MMBtu	Limited Operation; Flare Work Practices; Flaring Minimization Plan

Table C-2. CO BACT Limits

EU ID	Description	BACT Limit	BACT Control
1 – 6	1,113 MMBtu/hr Simple Cycle Treated Gas Compressor Turbines	5 ppmvd at 15% O_2	Oxidation Catalyst; Good Combustion Practices
7 – 10	384 MMBtu/hr Combined Cycle Power Generation Combustion Turbines	5 ppmvd at 15% O_2	Oxidation Catalyst; Good Combustion Practices
11	575 hp Firewater Pump Engine (ULSD)	3.3 g/hp-hr	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
12	300 hp Auxiliary Air Compressor Engine (ULSD)	3.3 g/hp-hr	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
13	Vent Gas Disposal (Thermal Oxidizer) 6.0 MMBtu/hr	0.082 lb/MMBtu	Proper Equipment Design; Good Combustion Practices
14 – 20	Vent Gas Disposal (Flares) 2.1 – 55,000 Mscf/hr	0.31 lb/MMBtu	Limited Operation; Flare Work Practices; Flaring Minimization Plan

Table C-3. Particulate BACT Limits

EU ID	Description	BACT Limit	BACT Control
1 – 6	1,113 MMBtu/hr Simple Cycle Treated Gas Compressor Turbines	0.0070 lb/MMBtu	Clean Fuel; Good Combustion Practices
7 – 10	384 MMBtu/hr Combined Cycle Power Generation Combustion Turbines	0.0070 lb/MMBtu	Clean Fuel; Good Combustion Practices
11	575 hp Firewater Pump Engine (ULSD)	0.19 g/hp-hr	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
12	300 hp Auxiliary Air Compressor Engine (ULSD)	0.022 g/hp-hr	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
13	Vent Gas Disposal (Thermal Oxidizer) 6.0 MMBtu/hr	0.0075 lb/MMBtu	Proper Equipment Design; Good Combustion Practices
14 – 20	Vent Gas Disposal (Flares) 2.1 – 55,000 Mscf/hr	40 µg/L 0.028 lb/MMBtu	Limited Operation; Flare Work Practices; Flaring Minimization Plan

Table C-4. SO_2 BACT Limits

EU ID	Description	BACT Limit	BACT Control
1 – 6	1,113 MMBtu/hr Simple Cycle Treated Gas Compressor Turbines	≤16 ppmv sulfur content in natural gas	Clean Fuel; Good Combustion Practices
7 – 10	384 MMBtu/hr Combined Cycle Power Generation Combustion Turbines	≤16 ppmv sulfur content in natural gas	Clean Fuel; Good Combustion Practices
11	575 hp Firewater Pump Engine (ULSD)	≤15 ppmw sulfur content in diesel fuel	Good Combustion Practices & ULSD; Limited Operation; 40 CFR 60 Subpart IIII
12	300 hp Auxiliary Air Compressor Engine (ULSD)	≤15 ppmw sulfur content in diesel fuel	Good Combustion Practices & ULSD; Limited Operation; 40 CFR 60 Subpart IIII
13	Vent Gas Disposal (Thermal Oxidizer) 6.0 MMBtu/hr	≤16 ppmv sulfur content in natural gas	Proper Equipment Design; Good Combustion Practices
14 – 20	Vent Gas Disposal (Flares) 2.1 – 55,000 Mscf/hr	≤16 ppmv sulfur content in natural gas	Limited Operation; Flare Work Practices; Flaring Minimization Plan

VOC BACT Limits

EU ID	Description	BACT Limit	BACT Control
1 – 6	1,113 MMBtu/hr Simple Cycle Treated Gas Compressor Turbines	0.0022 lb/MMBtu	Oxidation Catalyst; Good Combustion Practices
7 – 10	384 MMBtu/hr Combined Cycle Power Generation Combustion Turbines	0.0022 lb/MMBtu	Oxidation Catalyst; Good Combustion Practices
11	575 hp Firewater Pump Engine (ULSD)	0.19 g/hp-hr	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
12	300 hp Auxiliary Air Compressor Engine (ULSD)	0.22 g/hp-hr	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
13	Vent Gas Disposal (Thermal Oxidizer) 6.0 MMBtu/hr	0.0054 lb/MMBtu	Proper Equipment Design; Good Combustion Practices
14 – 20	Vent Gas Disposal (Flares) 2.1 – 55,000 Mscf/hr	0.66 lb/MMBtu	Limited Operation; Flare Work Practices; Flaring Minimization Plan
21 – 23	Gas Condensate Storage Tanks and Loading System (126,904 – 457,890 gallons)	N/A	Vapor Recovery and Routing to Thermal Oxidizer
23 – 25	Diesel Storage Tanks (342 – 3,520 gallons)	0.01 tpy	Submerged Fill

Table C-5. GHG BACT Limits

EU ID	Description	BACT Limit	BACT Control
1 – 6	1,113 MMBtu/hr Simple Cycle Treated Gas Compressor Turbines	117.1 lb/MMBtu	Clean Fuel; Good Combustion Practices
7 – 10	384 MMBtu/hr Combined Cycle Power Generation Combustion Turbines	117.1 lb/MMBtu	Clean Fuel; Good Combustion Practices
11	575 hp Firewater Pump Engine (ULSD)	163.6 lb/MMBtu	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
12	300 hp Auxiliary Air Compressor Engine (ULSD)	163.6 lb/MMBtu	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
13	Vent Gas Disposal (Thermal Oxidizer) 6.0 MMBtu/hr	117.1 lb/MMBtu	Proper Equipment Design; Good Combustion Practices
14 – 20	Vent Gas Disposal (Flares) 2.1 – 55,000 Mscf/hr	117.1 lb/MMBtu	Limited Operation; Flare Work Practices; Flaring Minimization Plan

Appendix D: Modeling Report

Alaska Department of Environmental Conservation
Air Permit Program

Review of
AGDC's Ambient Demonstration
for the
Alaska LNG Project's
Liquefaction Plant

Construction Permit AQ1539CPT01

Prepared by: James Renovatio
14 August, 2020

G:\AQ\PERMITS\AIRFACS\Alaska Gasline Dev Corp (AK LNG Project)\Liquefaction Plant (1539)\Construction\CPT01\Pre\AQ1539CPT01 Modeling Review.docx

Table of Contents

1. INTRODUCTION

This report summarizes the Alaska Department of Environmental Conservation's (Department's) findings regarding the ambient analysis submitted by the Alaska Gasline Development Corporation (AGDC) for the Liquefaction Plant of the Alaska Liquefied Natural Gas Project (AK LNG Project). AGDC submitted this analysis in support of their 1 May, 2018 air quality control permit application (AQ1539CPT01) submitted under the Prevention of Significant Deterioration (PSD) requirements listed in 18 AAC 50.306 and the major source of hazardous air pollutant (HAP) requirements listed in 18 AAC 50.316. The potential emissions for the Liquefaction Plant trigger the PSD permit requirements for the following air pollutants: oxides of nitrogen (NOx), particulate matter with an aerodynamic diameter of 10 microns or less (PM-10), particulate matter with an aerodynamic diameter of 2.5 microns or less (PM-2.5), sulfur dioxide (SO_2), carbon monoxide (CO), volatile organic compounds (VOC), and greenhouse gases (GHG).

AGDC provided the PSD source impact analysis required under 40 CFR 52.21(k), the pre-construction monitoring analysis required under 40 CFR 52.21(m)(1), and the additional impact analysis required under 40 CFR 52.21(o). AGDC demonstrated that operating the Liquefaction Plant emissions units (EUs) within the restrictions listed in this report will not cause or contribute to a violation of the following Alaska Ambient Air Quality Standards (AAAQS) listed in 18 AAC 50.010: one-hour nitrogen dioxide (NO_2), annual NO_2, 24-hour PM-10, 24-hour PM-2.5, annual PM-2.5, one-hour SO_2, three-hour SO_2, 24-hour SO_2, annual SO_2, one-hour CO, eight-hour CO, and eight-hour ozone (O_3). AGDC also demonstrated that the Liquefaction Plant emissions will not cause or contribute to a violation of the following Class I and Class II maximum allowable increases (increments) described in 18 AAC 50.020: annual NO_2, 24-hour PM-10, annual PM-10, 24-hour PM-2.5, annual PM-2.5, three-hour SO_2, 24-hour SO_2, and annual SO_2.[1]

2. PROJECT BACKGROUND

The Liquefaction Plant will be a new stationary source located on the eastern shore of Cook Inlet just south of the existing Agrium fertilizer plant on the Kenai Peninsula. The project scope is fully described in AGDC's *Resource Report 1* (General Project Information) of the AK LNG Project, which AGDC provided as Attachment 2 of their permit application. In summary, the Liquefaction Plant will liquefy gas received from the North Slope via pipeline in order for it to be shipped to market. The Liquefaction Plant will include three parallel liquefaction trains, along with power generation, auxiliary equipment, and a marine terminal. Each train will include two gas-fired Gas Compression turbines. Additional background information regarding the Liquefaction Plant, the ambient demonstration requirements, and various procedural issues, are provided below.

[1] There are no ambient demonstration requirements for GHG emissions since there are no GHG AAAQS or increments.

2.1. Area Classification

The project site is in an area that is unclassified in regards to compliance with the AAAQS. For purposes of increment compliance, the project site is within a Class II area of the Cook Inlet Intrastate Air Quality Control Region. The nearest Class I areas[2] are Tuxedni National Wildlife Refuge (Tuxedni), which is managed by the US Fish and Wildlife Service (FWS), and Denali National Park (Denali), which is managed by the National Park Service (NPS). Tuxedni is located 86 kilometers (km) to the south, and Denali is located approximately 183 km to the north.

2.2. Ambient Demonstration Requirements

The State of Alaska's PSD requirements are described in 18 AAC 50.306. PSD applicants must essentially comply with the federal PSD requirements in 40 CFR 52.21. Except as noted in 40 CFR 52.21(i), the ambient requirements include:

- <u>Stack Height</u> considerations, per 40 CFR 52.21(h);
- A <u>Source Impact Analysis,</u> i.e., an ambient demonstration for the PSD-triggered pollutants with an associated ambient air quality standard or increment, per 40 CFR 52.21(k);
- An <u>Air Quality Analysis</u>, i.e., pre-construction monitoring data, for the PSD-triggered pollutants with an associated ambient air quality standard or increment, per 40 CFR 52.21(m);
- An <u>Additional Impact Analysis</u> per 40 CFR 52.21(o); and
- A <u>Class I Impact Analysis</u>, for stationary sources that may affect a Class I area, per 40 CFR 52.21(p).

40 CFR 52.21(p) also requires the Department to notify the Federal Land Manager (FLM) of a potentially affected Class I area. 40 CFR 52.21(p)(2) states the FLM has "…*an affirmative responsibility to protect the air quality related values (including visibility) of such lands and to consider, in consultation with the [reviewing authority], whether a proposed source or modification will have an adverse impact on such values.*" EPA has elaborated on the FLM notification requirement by saying the permitting authority must provide notification for any PSD project located within 100 km of the Class I area, or for "very large [PSD] sources" located beyond 100 km.[3] The FLMs have defined the large source threshold for stationary sources located greater than 50 km away through an emissions-to-distance (Q/d) evaluation contained in the *Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase 1 Report – Revised (2010)*.[4] Q/d values that are less than 10 indicate the given PSD

---

2 Class I areas are defined as national parks over 6,000 acres and wilderness areas and memorial parks over 5,000 acres, established as of 1977. All other federally managed areas are designated as Class II areas. The Class I areas within Alaska are listed in Table 1 of 18 AAC 50.015(c)(2).

3 EPA has issued several guidance documents over the past few decades that reference the 100 km notification range. EPA summarized this long-standing policy in a 11 January, 2017 letter from Anna Marie Wood (Director, Air Quality Policy Division) to Carol McCoy (Chief, Air Resources Division of the NPS).

4 FLAG information, including the 2010 Phase I Report may be found at: https://www.nature.nps.gov/air/Permits/flag/index.cfm.

project will have negligible impacts with respect to Class I Air Quality Related Values (AQRVs).

Tuxedni is located within the 100 km notification range. The Q/d ratio also exceeds 10 at both Tuexedni and Denali. The Department, therefore, notified the FWS and the NPS of the pending PSD application on 12 October, 2017.[5] The FWS responded the same day by saying they would like to kept informed and that they wanted to discuss the AQRV evaluation.[6] The NPS expressed their interest during a 24 October, 2017 teleconference with the FLMs.

There are no ambient demonstration requirements under the major HAP permit classification. Therefore, AGDC was only required to provide the PSD demonstrations described at the beginning of Section 2.2.

2.3. Increments and Baseline Dates

For air quality modeling purposes, the term "increment" regards the maximum allowed increase in ambient concentration that may occur in a given area. The increment is determined relative to the "baseline concentration," which reflects the concentration that occurred, or was accounted for, at the time of a set baseline date. Congress set 6 January, 1975 as the major source baseline date for the 24-hour and annual PM-10 increments, and the three-hour, 24-hour, and annual SO_2 increments. The U.S. Environmental Protection Agency (EPA) established 8 February, 1988 as the major source baseline date for the annual NO_2 increment, and 20 October, 2010 as the major source baseline date for the 24-hour and annual PM-2.5 increments. There are no one-hour SO_2 or one-hour NO_2 increments. The minor source baseline dates for the Cook Inlet Intrastate Air Quality Control Region are listed in Table 2 of 18 AAC 50.020. All of the combustion-related EUs at the Liquefaction Plant will consume increment for the pollutants and averaging periods described within this paragraph since the emissions will occur after the applicable major source baseline dates.

2.4. Additional Comments Regarding Various Procedural Issues

2.4.1. Interface with the National Environmental Policy Act

AGDC conducted various air quality demonstrations under the National Environmental Policy Act (NEPA) prior to submitting their permit application for the Liquefaction Plant.[7] They therefore relied on these previous demonstrations, to the extent possible, for the ambient analyses required under PSD. This type of coordinated approach is encouraged by EPA under 40 CFR 52.21(s). The Department has not adopted this citation by reference (since it has no control over the federal actions conducted under NEPA), but the Department nevertheless agrees that the analyses should be consistent where possible.

[5] Email from James Renovatio (Department) to Andrea Stacy (NPS) and Catherine Collins (FWS), *Alaska LNG – Liquefaction Class I impacts for proposed PSD permitting*; 12 October, 2017.

[6] Email from Catherine Collins (FWS) to James Renovatio and Alan Schuler (Department), *Re: Alaska LNG – Liquefaction Class I impacts for proposed PSD permitting*; 12 October, 2017.

[7] The Federal Energy Regulatory Commission (FERC) is the lead agency for the NEPA review.

The Department notes, however, that while the PSD and NEPA requirements contain a number of similar air quality provisions, they are not fully identical. This report does not delve into those differences; but AGDC summarized them with respect to the Liquefaction Plant project in Attachment 2 of their PSD modeling protocol.

2.4.2. Modeling Protocol Submittal

AGDC submitted a modeling protocol for the PSD ambient demonstration for Liquefaction Plant on 5 October, 2017. The Department approved the protocol, with comment, on January 17, 2018. The Department issued an erratum on 7 February, 2018 to clarify potentially confusing statements and to address an unintentional omission.

2.4.3. Guideline on Air Quality Models

The ambient demonstrations submitted in support of a permit application must comply with the air quality models, databases, and requirements specified of 40 CFR 51, Appendix W (*Guideline on Air Quality Models*), per 18 AAC 50.215(b), or an alternative modeling approach approved under 18 AAC 50.215(c). This basic requirement is reiterated for PSD applicants in 40 CFR 52.21(l), which the Department has adopted by reference in 18 AAC 50.040(h)(10).

EPA has made a number of updates to the *Guideline on Air Quality Models* (Guideline) over time. The Department used the 2005 version of the Guideline for the Liquefaction Plant modeling review since that was the version adopted by reference in 18 AAC 50.040(f) at the time of the protocol review.[8] EPA had previously promulgated an update to the Guideline on 17 January, 2017, but they also provided a one year transition period for the permitting authorities to incorporate the update into their air permit programs. EPA further stated:

> *During the one year period following promulgation, protocols for modeling analyses bases on the 2005 version of the Guideline, which are submitted in a timely manner, may be approved at the discretion of the reviewing authority*.

The Department approved AGDC's PSD modeling protocol on 17 January, 2018, which is within the one year transition period. The Department's reliance on the 2005 version of the Guideline for the Liquefaction Plant permit is therefore consistent with State rule, and allowed under Federal rule.

2.4.4. Application Submittal

AGDC provided the Department with an application for their permit on 1 May, 2018. The Department requested additional information[9] on 29 June, 2018, 3 December, 2019,

---

[8] At the time of the protocol review, 18 AAC 50.040(f) referred to the version of the Guideline "*revised as of July 1, 2015*." The date refers to the latest version of 40 CFR 51 available when 18 AAC 50.040(f) was last updated. However, the latest version of the Guideline at that time was the version published in the Federal Register on 9 November, 2005.

[9] The Department made additional information requests regarding non-modeling related issues, but they are not discussed in this Modeling Report.

and 28 April, 2020. AGDC provided responses to these requests, including supplemental files, on 24 September, 2018, 10 January, 2020, and 5 May, 2020, respectively.

3. REPORT OUTLINE

The Department's findings regarding AGDC's approach for meeting the pre-construction monitoring requirement in 40 CFR 52.21(m) is described in Section 4 (**Pre-Construction Monitoring Data**) of this report. The Department's findings regarding the additional impact analysis conducted under 40 CFR 52.21(o) is described in Section 9 (**Additional Impact Analysis**) of the report.

AGDC used a variety of means to address the ambient demonstration requirement in 40 CFR 52.21(k). AGDC used computer analyses (modeling) to predict the ambient NO_2, SO_2, PM-10, CO, and direct PM-2.5 air quality impacts; ambient data to represent the existing secondary PM-2.5 impacts; and a qualitative analysis to address the ambient O_3 impacts and project-related secondary PM-2.5 impacts. The Department's findings regarding AGDC's near-field NO_2, SO_2, CO, PM-10, and PM-2.5 modeling analyses are provided in Section 5 (**Near-field Source Impact Analyses**) of this report. The results from the near-field assessments are discussed in Section 6 (**Near-field Modeling Results and Discussion**). The Department's findings regarding AGDC's far-field (Class I increment analysis) are provided in Section 7 (**Class I Analyses**), along with the Department's findings regarding AGDC's Class I AQRV analyses. The Department's findings regarding AGDC's O_3 analysis is in Section 8 (**Ozone Impacts**) of the report.

4. PRE-CONSTRUCTION MONITORING DATA

40 CFR 52.21(m)(1) requires PSD applicants to submit ambient air monitoring data describing the air quality in the vicinity of the project, unless the existing concentration or the project impact is less than the applicable Significant Monitoring Concentration provided in 40 CFR 52.21(i)(5). The requirement only pertains to those pollutants that are subject to PSD review and have a National Ambient Air Quality Standard (NAAQS).[10] If monitoring is required, the data are to be collected prior to construction. Hence, these data are referred as "pre-construction monitoring" data. Ambient "background" data may also be needed to supplement the estimated ambient impact from the proposed project. AGDC's approach for meeting the pre-construction data requirement is discussed below. Their approach for meeting the "background" data needs is described in Section 5.14 (**Off-Site Impacts***)* of this report.

Pre-construction monitoring data must be collected at a location and in a manner that is consistent with the EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA-450/4-87-007), which the Department adopted by reference in 18 AAC 50.035(a)(5). In summary, the data must be collected at the location(s) of existing and

[10] EPA has the authority under 40 CFR 52.21(m)(1)(ii) to require pre-construction monitoring for PSD-triggered pollutants that do not have a NAAQS (when they have shown a need for the data), but they have not made this determination for those pollutants.

proposed maximum impacts, the data must be current, and the data must meet PSD quality assurance requirements. The current quality assurance requirements are described in 18 AAC 50.215(a).

AGDC fulfilled the pre-construction monitoring requirements by collecting 12 months of PSD-quality ambient data for NO_2, SO_2, and CO from 1 September, 2018 through 31 August, 2019. They relied upon 12 months of representative PSD-quality data from Agrium U.S., Inc.'s nearby Nikiski monitoring station, collected between 2013 to 2014, to meet the requirement for PM-10, PM-2.5, and O_3[11].

For their site-specific data collection effort, AGDC provided a Quality Assurance Project Plan (QAPP) for Department review and approval, in order to assure they had an acceptable approach for obtaining ambient data. They also submitted the subsequent data sets for review and approval. The Department requested additional information associated with the resultant data12 on 19 February, 2020. AGDC provided a response to this request on 4 March, 2020. The resulting periods with PSD quality data are listed by pollutant in Table 1. The AAAQS and maximum concentrations, as measured according to the form of the given AAAQS, are also provided. The Department is reporting the gaseous pollutants on a mass basis in micrograms per cubic meter ($\mu g/m^3$) which is the convention used in modeling, rather than on a volumetric basis in parts-per-million (ppm), which is the convention typically used in monitoring reports.

Table 1. AGDC's 2018-2019 Pre-Construction Monitoring Data

Air Pollutant	Avg. Period	Monitoring Period	Max Conc ($\mu g/m^3$)	AAAQS ($\mu g/m^3$)	% of AAAQS
NO_2	1-hour	2018-2019	**59.4**	188	31.6
	Annual		**7.5**	100	7.5
SO_2	1-hour		**20.4**	196	10.4
	3-hour		**0.0**	1,300	≈ 0
	24-hour		**0.0**	365	≈ 0
	Annual		**0.0**	80	≈ 0
CO	1-hour		**2,291**	40,000	5.7
	8-hour		**1,145**	10,000	11.5

Table Notes:
Some of the tabular values are slightly different from the values reported in AGDC's data. The differences are due to variation in rounding practices when converting values from a volumetric basis to a mass basis. None of the differences are substantive, nor do they alter the conclusion that the measured concentrations currently demonstrate compliance with the AAAQS.

[11] The Department provided its tacit approval for this representative approach by e-mail; *ADEC Response Re Nikiski Pre-Construction Monitoring*; 13 June, 2017.
[12] This information generally pertains to the precision of monitored three-hour, 24-hour, and annual SO_2 data and CO instrumentation. It is detailed in an e-mail; *AK LNG Nikiski Preconstruction Monitoring Annual Data Report action items*; 19 February, 2020.

Data germane to AGDC's use of representative PSD-quality data from Agrium U.S., Inc.'s nearby Nikiski monitoring station are presented in Table 2. These data include the AAAQS and maximum concentrations, as measured according to the form of the given AAAQS. Particulates are only measured and reported on a mass basis and are, therefore, presented on a mass basis.

Table 2. Agrium U.S. Inc.'s 2013-2014 Pre-Construction Monitoring Data

Air Pollutant	Avg. Period	Monitoring Period	Max Conc (μg/m^3)	AAAQS (μg/m^3)	% of AAAQS
PM-10	24-hour	2013-2014	**49.0**	150	32.7
PM-2.5	24-hour		**24.0**	35	68.6
	Annual		**3.7**	12	30.8
O_3	8-hour		**100**	140	71.4

Tables 1 and 2 show that the local air quality currently complies with the AAAQS for each PSD-triggered pollutant.

5. NEAR-FIELD SOURCE IMPACT ANALYSES

As previously mentioned in Section 3, AGDC conducted air quality modeling analyses to estimate their ambient near-field NO_2, SO_2, CO, PM-10, and direct PM-2.5 impacts. The various aspects of their modeling analyses are discussed below.

5.1. Approach

AGDC used a "normal operations" modeled scenario to provide a conservative estimate of the Liquefaction Plant ambient impacts. This scenario is generally characterized by the full-capacity operation of all three compression turbine trains and the associated power generation units, in addition to non-transient marine terminal emissions and the limited use of various emergency and intermittently used EUs. Additional information regarding this scenario is available in Section 4.1.1 of the Liquefaction Plant Modeling Report.[13] AGDC did not model other operational scenarios, e.g., plant start-up, early plant operations, and maintenance operations, under the assumption that these scenarios would have fewer emissions and, consequently, smaller ambient impacts. Similarly, they did not model the Liquefaction Plant construction phase for the reasons described in Section 5.6.3 of this report. AGDC's modeled approach emphasizing the "normal operations" scenario is reasonable.

AGDC used a two-step approach for modeling the normal operations scenario. They first compared the ambient impact from just the Liquefaction Plant EUs, i.e., the project impacts, to the significant impact levels (SILs) listed in Table 5 of 18 AAC 50.215(d). Impacts less

[13] Provided by AGDC to FERC as Attachment 5: Appendix D of Resource Report 9.

than the SIL are considered negligible. They then conducted a cumulative impact analysis for those pollutants and averaging periods with significant impacts. The cumulative impacts are compared to the AAAQS or increment, as applicable.

A cumulative AAAQS demonstration incorporates the impacts from natural and regional sources, along with long-range transport from far away sources. The impacts are accounted for through a combination of modeling and representative air quality monitoring data (aka background data). EPA discusses this overall approach in Section 8.2 of the Guideline. As stated in Section 8.2.3, "*…all sources expected to cause a significant concentration gradient in the vicinity of the [applicant's source] should be explicitly modeled.*" The impact from other sources can be accounted for through representative background data.

The increment consuming impact from off-site sources must likewise be accounted for in a cumulative increment demonstration. The approach for incorporating these impacts must be evaluated on a case-specific basis for each pollutant. Background data is not generally used in a cumulative increment analysis since it typically overstates the off-site increment consumption – i.e., it reflects the total air quality concentration rather than the *change* in concentration subsequent to the increment baseline date (see Section 2.3 of this report). Applicants instead typically model the nearby increment consuming EUs, and when warranted, the off-site increment expanding EUs.

As subsequently discussed in Section 6 of this report, *Modeling Results and Discussion*, project impacts for the Liquefaction Plant exceed the SIL for most of the modeled pollutants and averaging periods. AGDC, therefore, included several off-site sources[14] in their cumulative impact analyses noting the likelihood for significant concentration gradients near the Liquefaction Plant. The following sub-sections provide additional details regarding AGDC's modeling analysis.

5.2. Model Selection

There are a number of air dispersion models available to applicants and regulators. EPA lists these models in the Guideline. AGDC used EPA's AERMOD Modeling System (AERMOD) for their ambient analyses. AERMOD is an appropriate modeling system for this permit application.

The AERMOD Modeling System consists of three major components: AERMAP, used to process terrain data and develop elevations for the receptor grid and EUs; AERMET, used to process the meteorological data; and the AERMOD dispersion model, used to estimate the ambient pollutant concentrations. EPA has also developed an AERMET support program, AERMINUTE, to calculate hourly average wind speeds and directions from one-minute Automated Surface Observing System (ASOS) data. AGDC used the versions of AERMAP, AERMINUTE, AERMET, and AERMOD that were current at the time that they conducted

[14] These sources include the Agrium Kenai Nitrogen Operations Plant and Loading Terminal, Conoco Phillips Kenai LNG Facility, Homer Electric Association Bernice Lake Power Plant, Homer Electric Association Nikiski Generation Plant, Tesoro Kenai Pipeline Marine Loading Terminal, and Tesoro Refinery.

their NEPA analysis: AERMAP version 11103; AERMINUTE version 14337 (AERMINUTE 14337), AERMET version 15181 (AERMET 15181); and AERMOD version 15181 (AERMOD 15181).

EPA has issued an AERMAP update, an AERMINUTE update, and two AERMOD/AERMET updates, subsequent to AGDC's NEPA analysis. EPA released the AERMINUTE update on 29 September, 2015 and the first AERMET/AERMOD update on 20 December, 2016; a subsequent correction to AERMOD was issued on 18 January, 2017. EPA identified the updates as AERMINUTE version 15272 (AERMINUTE 15272), AERMET version 16216 (AERMET 16216), and AERMOD version 16216r (AERMOD 16216r). AGDC acknowledged these updates in their PSD modeling protocol, but they also expressed a desire to maintain consistency with the NEPA analysis (see the related discussion in Section 2.4.1). AGDC nevertheless stated that they would conduct a sensitivity analysis to confirm that the results using AERMOD/AERMET 15181 are still valid. The Department conditionally approved AGDC's proposed use of AERMOD/AERMET 15181, but noted that AGDC would need to use the current version of AERMET and AERMOD if:

- The sensitivity analysis shows that the maximum impacts may have been underestimated when using AERMET/AERMOD 15181;
- There are substantive changes in the EU inventory, emissions, or stack parameters that warrant an updated modeling analysis, and/or;
- AGDC, or the Department, finds that the tall tower meteorological data collected at Nikiski leads to materially greater impacts than the Kenai meteorological data used for the NEPA analysis.

AGDC provided the sensitivity analysis in Attachment 8 of their permit application. The analysis shows that AERMINUTE 15272, AERMET 16216, and AERMOD 16216r provide nearly identical results as AERMET/AERMOD 15181, as further elaborated in Section 5.2.1 below.

EPA released another AERMET/AERMOD update, along with an update to AERMAP, on 24 April, 2018. They identified these updates as AERMAP version 18081 (AERMAP 18081), AERMET version 18081 (AERMET 18081), and AERMOD version 18081 (AERMOD 18081). The Department does not generally make applicants update their ambient demonstrations if there is a model update subsequent to the Department's approval of the modeling protocol. The Department nevertheless reviewed the Model Change Bulletins (MCB) that EPA issued with the updates to determine whether EPA found and corrected substantive coding errors. EPA only made two changes to AERMAP: they revised an array so that AERMAP can be ran on a Linux platform; and they expanded the command line option so that the user can specify the input and output filenames. None of these changes affect AGDC's modeling analysis.

EPA made a number of changes to AERMOD and AERMET; but none of them would lead to an increased impact in the Liquefaction Plant modeling analysis. The Department nevertheless reran AGDC's 24-hour PM-2.5 and one-hour NO_2 sensitivity analyses using

AERMET/AERMOD 18081 to further confirm that the AERMET/AERMOD versions used by AGDC remains acceptable. The Department's sensitivity analyses are further discussed below.

5.2.1. AERMOD Sensitivity Analyses

AGDC re-ran their one-hour NO_2 and 24-hour PM-2.5 cumulative impact AAAQS analyses observing the former as yielding worst-case estimated ambient impacts. They used AERMINUTE 15272, AERMET 16216 and AERMOD 16216r for these sensitivity analyses. AGDC relied upon the 2008 through 2012 meteorological dataset used in their underlying NEPA analyses; see Section 5.3 of this report for additional detail.[15]

AGDC correctly noted that EPA changed a default setting in AERMOD 16216r regarding the Ambient Ratio Method 2 (ARM2) NO_2 modeling technique used by AGDC. The setting regards the Minimum Ambient Ratio (MAR), which provides the lower bound of the NO_2 to oxides of nitrogen (NOx) ratio in the atmosphere. The default value increased from 0.2 in AERMOD 15181 to 0.5 in AERMOD 16216r. AGDC used the original 0.2 default value in their NEPA analysis.

AGDC provided additional information in Attachment 8 as to why they believe a 0.2 MAR is appropriate for the Liquefaction modeling analysis. The Department's findings regarding the MAR setting is provided in Section 5.10.1, *Ambient NO_2 Modeling*, of this report. The Department is only providing the 0.2 MAR results in the following discussion in order to maintain consistency in the version sensitivity analysis.

The modeled design concentration from each AERMOD version are provided in Table 3 of this report; Design concentrations are discussed in Section 5.15 of this report. The design concentrations are nearly identical for each pollutant. The sensitivity analyses therefore show that AGDC's use of AERMINUTE 14337, AERMET 15181, and AERMOD 15181 remains acceptable for the Liquefaction Plant PSD application.

Table 3. AERMOD Sensitivity Results (μg/m^3)

Pollutant and Averaging Period	Modeled Design Concentration When Using AERMOD Version:		
	15181	16216r	18081
one-hour NO_2	149.47826	149.49961	149.57037
24-hour PM-2.5	6.38954	6.38955	6.35817

15 Table 1 of Attachment 8 of AGDC's permit application erroneously lists 2011 through 2015 as the modeled period for the NEPA/sensitivity analyses. The modeling files show that AGDC used 2008 through 2012 data for these analyses.

5.3. Meteorological Data

AERMOD requires hourly meteorological data to estimate plume dispersion. A *minimum* of one-year of site-specific data, or five years of representative National Weather Service (NWS) data should be used, per Section 8.3 of the Guideline. The data must also be "both laterally and vertically representative of the transport and dispersion within the analysis domain," per Section 8.3.c of the Guideline.

AGDC used the same five years of NWS data as used by other recent applicants for this area: 2008 through 2012 data from the Kenai airport data alongside upper-air data from Anchorage. The Department previously posted the data in an AERMOD-ready format at: http://dec.alaska.gov/air/air-permit/aeromod-met-data/. The AERMOD-ready data was available when AGDC started their analysis, but it had not been reprocessed with the then current version of AERMINUTE and AERMET (AERMINUTE 15272 and AERMET 15181). AGDC, therefore, reprocessed the data, which they provided as part of their permit application. Additional comments regarding the meteorological data is provided below.

5.3.1. Tall Stack Considerations

Some of the proposed exhaust stacks will be substantially taller than the Kenai airport anemometer. The tallest stacks will be 64 meters (m) high whereas the anemometer is only eight m high. The Department, therefore, questioned whether the Kenai NWS data would be representative of the plume transport conditions during pre-application discussions with AGDC's predecessor, Alaska LNG.

Alaska LNG agreed to collect at least 12-months of tall tower meteorological data to assess the adequacy of using Kenai NWS data. Alaska LNG then used the data to conduct a sensitivity analysis, which AGDC provided as Attachment C to Attachment 3 of their permit application. AGDC concluded:

> *The results of dispersion modeling of emissions from all sources at the proposed Plant have been shown to be quite insensitive to the selection of meteorological input data. Only small differences in predicted maximum 1-hour NO_2, Annual NO_2, 24-hour PM2.5, and Annual PM2.5 concentrations were observed between model simulations that used multiple-level meteorological data from the Nikiski tower or the 8-meter data from the NWS station at Kenai*.

The Department's findings regarding the data collection and sensitivity analysis are provided below.

5.3.1.1 Tall Tower Data Collection

Alaska LNG proposed a site in Nikiski for a 60-meter tower on 25 February, 2014 and submitted a slightly revised location on 6 June, 2014. The Department approved the revised location on 13 June, 2014. The Department approved the subsequently submitted Quality Assurance Project Plan on 20 April, 2015.

Alaska LNG collected wind data at 10 m, 30 m, and 60 m heights. However, only the 30 m and 60 m heights meet the siting requirements established in EPA's *Meteorological Monitoring Guidance for Regulatory Modeling Applications* (EPA-454/R-99-005). The 10 m wind data do not meet the setback requirements due to a large number of nearby trees that could not be removed. The other parameters that Alaska LNG measured, at various heights, included: temperature, relative humidity, solar radiation, barometric pressure, precipitation, and vertical wind speed.

Alaska LNG submitted 12-months of data for calendar year 2015 on 29 March, 2016. The data were reviewed on behalf of the Department by ASRC Energy Services (ASRC). The Department accepted ASRC's conclusion that all of the measured and calculated parameters are PSD quality, except for the 10 m wind data, on 21 July, 2016.

5.3.1.2 Analysis Criteria

The Department asked AGDC to provide the sensitivity analysis using the tall tower data in the Department's 17 January, 2018 approval of the PSD modeling protocol. The Department asked for the analysis since some of the exhaust stacks will be more than 50 m tall; see Section 5.7.6 of this report. The Department stated:

> *AGDC will need to provide an AERMOD sensitivity analysis using the 60 meter meteorological data that they collected at Nikiski to support their use of the eight meter Kenai meteorological data for the ambient demonstration to be submitted with their application for a PSD permit. This analysis should compare the modeled design concentrations when using the Kenai data to the modeled design concentrations when using the Nikiski data. Areas of potential impact should be identified and accompanied by relevant discussion, such as the lack of 10 meter wind data from Nikiski. AGDC may limit the analysis to just the worst-case pollutants, rather than modeling all of the PSD-triggered pollutants, so long as they assesses an annual, a 24-hour, and a one-hour impact. The analysis should be conducted at the project impact level rather than the cumulative impact level.*

5.3.1.3 Analysis and Review

AGDC provided a comparison of the observed winds, as well as a comparison of the modeled impacts. They compared the annual wind rose from the 30-m Nikiski data to the annual wind rose from the eight-m Kenai data for calendar year 2015. They correctly stated, "*In general, the wind roses are similar with a few notable differences, such as an apparent shift in the prevailing winds from southerly winds at Nikiski toward southwesterly winds at Kenai.*" They provided a reasonable discussion regarding the similarities and differences. They appropriately noted that annual frequency plots highlight general patterns, but they "*…are not generally useful for comparing winds over short-term averaging periods or for providing* *information on where maximum short-term pollutant concentrations will be predicted.*"

AGDC, then Alaska LNG, [16] conducted the AERMOD sensitivity analysis at the project impact level, rather than the cumulative impact level. They stated the nearby offsite sources were not included in the analysis "*...because (1) they were not the focus of the permitting, (2) they are generally comprised of sources with shorter stacks, and (3) [the Department] has approved modeling these sources with meteorological data collected at 10 meters or less.*" The Department agrees with AGDC's reasoning and approach.

AGDC included the full project EU inventory in the analysis, rather than just the EUs with tall stacks. They stated a culpability analysis showed little difference in results between a full inventory and tall stack inventory. Therefore, they used the full inventory for simplicity. The Department agrees with the full project inventory approach.

AGDC used AERMET/AERMOD version 15181 for the analysis. They compared the modeled one-hour NO_2, 24-hour PM-2.5, annual NO_2, and annual PM-2.5 impacts for the following three meteorological datasets:

1) eight-m Kenai data from 2015;
2) 30-m and 60-m Nikiski data from 2015; and
3) 30-m Nikiski data from 2015, i.e., without the 60 m data.

The modeled design concentrations[17] from the three datasets are similar, but not identical, as shown in Table 4. The dataset with the largest value varies by pollutant and averaging period. The Kenai data generally provided the largest concentration, but both the Nikiski datasets provided the largest 24-hour PM-2.5 values.

Table 4. Tall Tower Sensitivity Results (μg/m^3)

Pollutant	Avg. Period	Modeled Design Concentration When Using the Following Meteorological Data:		
		Kenai (8-m Tower)	**Nikiski** (30- and 60-m Measurements)	**Nikiski** (30-m Measurements)
NO_2	one-hour	141.2	135.4	133.3
	Annual	8.56	7.63	7.41
PM-2.5	24-hour	3.72	4.14	4.06
	Annual	0.42	0.42	0.36

[16] The Department will use "AGDC" as a simplification of "Alaska LNG/AGDC" from this point forward, rather than attempting to differentiate which party conducted which part of the tall tower sensitivity analysis/write-up.

[17] Design concentrations are discussed in Section 5.15 of this report.

The analytical results[18] of AGDC's sensitivity analyses suggest that meteorological measurements between the heights considered demonstrate little impact on the associated estimated model output. Their results further suggest that impacts at the Liquefaction Plant are driven by the emissions from stacks with release points above 20 m in height, rather than those with releases below this height. Based on a review of these results, the Department finds that AGDC's use of 10-m meteorological data is acceptable for modeling the proposed Liquefaction Plant stationary source, but notes that this conclusion cannot be generally applied to all stationary sources with tall stacks; see the associated discussion in the Modeling Report for AGDC's GTP stationary source for relevant detail.

5.3.2. Processing the NWS Data

As previously noted in Section 5.2 of this report, AGDC used AERMINUTE 14337 and AERMET 15181 to reprocess the 2008 – 2012 NWS data. AERMINUTE requires the user to provide the start-up date for the Ice Free Winds (IFW) setting, which is the date the NWS started using a sonic anemometer at that station. AGDC continued to use the 21 September, 2006 IFW commission date for the Kenai airport station.

AERMET requires the area surrounding the surface meteorological tower to be characterized with regard to the following three surface characteristics: noon-time albedo, Bowen ratio, and surface roughness length. AGDC continued to use the previously approved values, which are repeated below in Table 5.

Table 5. Approved AERMET Surface Parameters for Kenai NWS Data

Surface Parameter	Spring	Summer	Autumn	Winter
Albedo	0.143	0.145	0.152	0.406
Bowen Ratio	0.509	0.395	0.658	0.426
Surface Roughness Length (m)				
Sector 1 (30º - 60º)	0.071	0.112	0.071	0.005
Sector 2 (60º - 90º)	0.138	0.197	0.138	0.022
Sector 3 (90º - 120º)	0.140	0.176	0.140	0.045
Sector 4 (120º - 150º)	0.141	0.177	0.141	0.046
Sector 5 (150º - 180º)	0.073	0.109	0.073	0.008
Sector 6 (180º - 210º)	0.050	0.069	0.050	0.008
Sector 7 (210º - 240º)	0.036	0.060	0.036	0.002
Sector 8 (240º - 270º)	0.078	0.104	0.078	0.019
Sector 9 (270º - 330º)	0.034	0.050	0.034	0.004
Sector 10 (330º - 30º)	0.045	0.065	0.045	0.005

Table Note: For purposes of the Kenai NWS AERMET surface parameters, spring is defined as April through May, summer is defined as June through August, autumn is defined as September through October, and winter is defined as November through March.

[18] Provided by AGDC to FERC as Attachment C: Attachment 3 of Resource Report 9

AGDC instructed AERMET to randomize the wind direction by ± 5 degrees. Randomization of the wind direction is a long-standing practice when using *hourly* NWS data since the data are recorded to the nearest 10 degrees. However, EPA clarified in a March of 2013 memorandum that the use of hourly-averaged wind directions from AERMINUTE, "*…eliminates the need to randomize the wind directions associated with standard NWS observations.*" [19] The Department ran two sensitivity analyses to see whether the use of randomized winds in AERMET significantly affects AGDC's modeling results. It does not. The Department reran the 24-hour PM-10 increment analysis for the worst-case meteorological data year (2010) using the same version of AERMET and AERMOD as used by AGDC (i.e, AERMET/AERMOD 15181), but without randomization of the wind direction. The high second-high (h2h) design concentration matched AGDC's value, as did the high first-high (h1h) concentration. The Department also reran the annual NO_2 increment analysis from AGDC's AERMET/AERMOD 16216 sensitivity analysis for the maximum impact receptor when using a MAR of 0.2; see Section 5.2.1 of this report.[20] The maximum impact was marginally smaller (12.52613 $\mu g/m^3$ instead of 12.53158 $\mu g/m^3$), which is inconsequential. The Department therefore accepts AGDC's AERMET settings for the Liquefaction analysis. ***However, the Department encourages AGDC to use the non-randomization setting in the future***. The Department used the non-randomization setting in all AERMET/AERMOD 18081 runs that it conducted as part of its review.

AERMET contains an option for adjusting the surface friction velocity (ADJ_u*) parameter. EPA developed this option to correct AERMOD's tendency to overpredict impacts under stable, low wind conditions. AGDC did not use the ADJ_u* option for the Liquefaction Plant modeling analyses.[21] Some of the modeled results may therefore be overstated.

5.4. Coordinate System

Air quality models need to know the relative location of the EUs, structures (if applicable), and receptors, in order to properly estimate ambient pollutant concentrations. Therefore, applicants must use a consistent coordinate system in their analysis.

AGDC used the Universal Transverse Mercator (UTM) grid for their coordinate system. This is the most commonly used approach in AERMOD assessments. The UTM system divides the world into 60 zones, extending north-south, and each zone is 6 degrees wide in longitude. The modeled EUs, structures, and receptors are all located in UTM Zone 5. AGDC used the North American Datum of 1983 reference for each UTM coordinate.

[19] EPA Memorandum from Tyler Fox to Regional Modeling Contacts, *Use of ASOS meteorological data in AERMOD dispersion modeling;* 8 March, 2013.

[20] The Department reran the annual NO_2 increment analysis for the worst-case meteorological data year (2010).

[21] The ADJ_u* option was considered as an alternative modeling technique when AGDC conducted their NEPA modeling analysis. Alternative modeling techniques require case-specific justification and Department/R10 approval under 18 AAC 50.215(c).

5.5. Terrain

Terrain features can influence plume dispersion and the resulting ambient concentration. Digitized terrain elevation data is therefore generally included in a modeling analysis. AERMOD's terrain preprocessor, AERMAP, utilizes the terrain data to obtain the base elevations for the modeled EUs, buildings, and receptors; and to calculate a "hill height scale" for each receptor.

AGDC used National Elevation Dataset (NED) files for their terrain dataset. NED is the current terrain elevation dataset provided by the United States Geological Survey. AGDC's use of NED data is therefore reasonable and appropriate.

5.6. EU Inventory

The modeled EU inventory for the Liquefaction Plant is described below, along with the off-site inventory that AGDC used in the cumulative impact analyses. The secondary emissions required in a cumulative impact analysis are also discussed.

5.6.1. Liquefaction Plant EU Inventory

AGDC modeled the Liquefaction Plant compressor and power generation turbines, air compression and firewater pump engines, dry and wet ground flares, low pressure flare, and thermal oxidizer as described in their modeling report[22] provided as Appendix D to Resource Report 9. They additionally modeled emissions from the assumed marine terminal operations during vessel maneuvering, cool-down, hoteling, loading, and purging as described in Section 4.1.1.2 of the appended report. The location of the modeled EUs is provided in Figure 5-5 of the aforementioned report. AGDC characterized all of the EUs as point sources; see the associated discussion in Section 5.7 of this modeling report for additional detail. AGDC conservatively assumed that all the modeled EUs operate concurrently.

5.6.2. Off-site EU Inventory

AGDC included a number of off-site sources in their cumulative impact analyses as broached at the end of Section 5.1 of this report. A summary and characterization of the modeled off-site EUs are listed in Section 10 of Appendix A to AGDC's Modeling Report, itself provided as Appendix D to Resource Report 9.

AGDC used relevant information from a recent permitting effort at the nearby Kenai Nitrogen Operations stationary source to develop their off-site inventory for AAAQS and PSD increment analyses; the former includes information germane to those EUs that are increment consuming[23]. They also used 2011 information from the Department's point source inventory and National Emissions Inventory database to support their analyses. The off-site inventory varies by pollutant since the baseline date

[22] Specific detail on these modeled EUs are presented in Tables 4-1 through 4-3 of said report.
[23] AGDC summarized the installation/modification date and increment consuming status of their off-site EUs in Appendix A of the Liquefaction Plant Modeling Report, itself provided as Appendix D to Resource Report 9.

is pollutant-specific; additional detail is provided in Section 2.3 of this report. AGDC's characterization of the explicitly modeled off-site EUs offers a representative characterization of the associated sources. It is sufficient to estimate the impact from those sources anticipated to cause significant concentration gradients within the project area. The Department finds that the off-site inventory is appropriate for those pollutants and averaging periods considered.

5.6.3. Secondary Emissions Inventory

PSD applicants must include "secondary emissions" in their ambient demonstration, per 40 CFR 52.21(k)(1). EPA defines the term in 40 CFR 52.21(b)(18) as, "*emissions which would occur as a result of the construction or operation of a major stationary source… but do not come from the major stationary source…*" However, secondary emissions do not include "*any emissions which come directly from a mobile source*." Subsequent EPA guidance further clarifies that the definition in 40 CFR 52.21(b)(18) "*sets out four tests to be used in determining whether such emissions are to be included in air quality impact assessments for PSD purposes: the emissions must be specific, well defined, quantifiable, and impact the same general area*." [24]

The only secondary emissions that would occur due to the construction and operation of the Liquefaction Plant are the construction emissions that would occur within the local area. The emissions that would occur due to the remaining aspects of the AK LNG Project, including the construction/operation of the Pipeline Stations and the Gas Treatment Plant, are <u>not</u> secondary emissions for purposes of the Liquefaction Plant PSD review since they will not occur in the same general area as the Liquefaction Plant emissions.[25]

AGDC advanced a general discussion of their construction emissions in Section 4.1.3 of the Liquefaction Plant Modeling Report, provided as Appendix D to Resource Report 9; a more detailed discussion is provided in Appendix C to this report, *Emissions Associated with Project*. AGDC stated the Liquefaction Plant construction phase would last approximately eight years, beginning in the second year to follow the project authorization. They also indicate that construction of the Marine Terminal, while beginning contemporaneously, will span a four-year period. AGDC noted that the Liquefaction Plant construction efforts will be multifaceted and include differing time scales and site locations for the various activities. Their characterization of construction activities and the associated estimated emissions are anticipated to result in secondary emissions that are less than the operational emissions used in the modeling analysis.

[24] EPA letter from Edward F. Turek (Acting Assistant Administrator for Air, Noise and Radiation) to Allyn M. Davis (Director, Air and Hazardous Materials Division); *PSD Evaluation of Secondary Emissions for Houston Lighting and Power*; 17 March, 1981.

[25] The Gas Treatment Plant, and each of the Pipeline Stations, are separate stationary sources for air quality permitting purposes. The ambient impacts associated with each of those stationary sources will be assessed, as warranted, under the permit requirements for that stationary source.

Developing the parameters needed to correctly characterize and simulate constantly changing construction emissions, especially fugitive dust emissions, is challenging. In some cases, the resulting concentrations are questionable, if not overly conservative. The Department further notes that the modeling results generally lead to the imposition of fugitive dust control plans to minimize said impacts and/or requirements to install vertical, uncapped exhaust stacks on the construction camp engines to reduce the impacts from these combustion sources; see Sections 5.7.7 and 5.8.2 of this report for additional detail. The Department is, therefore, imposing its typical endpoint of the aforementioned reasoning, i.e. ambient air conditions, rather than requiring AGDC to develop the details needed to explicitly model their construction phase emissions. These construction phase conditions include:

- Fugitive dust control;
- A requirement to construct and maintain vertical, uncapped stacks on all temporary construction camp engines; and
- A requirement to install and operate PM-10 and PM-2.5 ambient air monitoring stations throughout the construction phase.

The ambient air monitoring provision includes an action plan that requires evaluation and possible further control of the dust-generating activities at set concentration levels.

5.7. Liquefaction Plant Emission Rates and Stack Parameters

The Department generally found the modeled emission rates to be consistent with the emissions information provided throughout their application. The modeled stack parameters are likewise generally reasonable. The exceptions, or items that otherwise warrant additional comment, are discussed below.

AGDC used the same EU inventory, emission rates, and stack parameters in the Class II increment analyses as used in the AAAQS demonstrations. This is an appropriate approach since the Liquefaction Plant EUs are increment consuming; see the associated discussion in Section 2.3 of this report.

5.7.1. Turbines

Six simple-cycle compression turbines (**EUs 1 through 6**) and four power generation turbines (**EUs 7 through 10**) will be installed and operated at the Liquefaction Plant. The power generation turbines will be equipped with Waste Heat Recovery Units (WHRUs) that are not designed with supplemental firing. For their WHRU-equipped turbines, AGDC's ambient demonstration appears to observe a regime of diminished exhaust temperature and momentum, relative manufacturer or vendor data for similar units, assuming a WHRU-diverted exhaust stream. For all modeled turbines, AGDC used exhaust parameters that reflected the anticipated worst-case loads and ambient temperatures to conservatively estimate both short-term and annualized ambient impacts; they assumed the full-time operation of all turbines. A detailed discussion of

ADGC's turbine modeling approach, including the specific release parameters, is detailed in their Modeling Report provided as Appendix D to Resource Report 9.

5.7.2. Thermal Oxidizer

A thermal oxidizer (**EU 13**) will be operated at the Liquefaction Plant for the destruction of VOCs. AGDC modeled this unit assuming a consistent flow of input gas across the year, i.e. 8,760 hr/yr. This characterization is appropriate for both annual and short-term AAAQS/increment demonstrations at the Liquefaction Plant.

5.7.3. Flares

Six ground flares (**EUs 14 through 19**), three dry three wet, will be installed and intermittently operated at the Liquefaction Plant as safety devices during relief, maintenance, and upset conditions. An elevated low-pressure flare (**EU 20**) will also be operated for various facility and Marine Terminal operations under similar episodic conditions. All flares are generally modeled using an assumption of continuous operation under their pilot/purge gas operational regimes, which is discrete from intermittent operation subject to relief, maintenance, and upset conditions. Operation during these conditions is reflected in AGDC's ambient demonstration with of 500 hr/yr of maximum impact flaring, each, for the ground flares and 144 hr/yr for the elevated low-pressure flare. While the latter scenarios are generally characterized as unplanned and/or episodic, intermittent flaring emissions are accounted for in the modeling by superposition of emission rates in both annual and short-term AAAQS/increment analyses; see the Department's Modeling Report for the GTP stationary source for a related discussion regarding AGDC's modeled short-term flaring assumptions. AGDC used the rated capacity of the flares to calculate the emissions and plume characteristics during their assumed flaring events.

Flares can typically be treated as point sources, but they require special handling since the emissions are generated outside of the flare stack. Most applicants use the approach described in Section 2.1.2 of EPA's AERSCREEN User's Guide, whereby the exhaust temperature is set to 1273K, the exit velocity is set to 20 meters per second (m/s), the stack height is the physical height plus flame length, and the stack diameter is based on the heat release rate. AGDC used the AERSCREEN approach for characterizing the pilot/purge conditions as well as the flaring events.

The maximum impact from episodic flaring events generally occurs well beyond the area of a stationary source's total maximum impact in the absence of significant complex terrain. This trend is especially salient in the case of the Liquefaction Plant due to large assumed flare plume heights given an extremely buoyant exhaust during flaring events and, in the case of the elevated low-pressure flare, a tall physical stack height; see Section 5.7.6 of this report for additional detail. As such, large effective stack heights of up to up to 172.8 m above base elevation, in the case of the ground flares, are used in AGDC's model inputs. These modeled stack heights, along with the additional plume rise from the high temperature release, lead to relatively large travel distances prior to plume touchdown.

An increased travel distance of flaring emissions from the Liquefaction Plant allows for increased dispersion of the associated ambient impacts. Consequently, the resulting impact from flaring is anticipated to be substantially smaller than the maximum total impact. Therefore, there is no need to incorporate AGDC's short-term flaring assumptions as permit conditions to protect ambient air quality.

5.7.4. Reciprocating Engines

AGDC intends to operate two reciprocating internal combustion engine (RICE) at the Liquefaction Plant, an emergency firewater pump (**EU 11**) and auxiliary air compressor (**EU 12**). For their ambient demonstration, AGDC assumed each RICE EU operates for only 500 hours-per-year (hr/yr). AGDC used this assumption to derive the emission rates used in the annual AAAQS/increment demonstrations and one-hour NO_2 and SO_2 AAAQS demonstrations. The annual emission rate may be used to characterize intermittently operated EUs in the one-hour NO_2 and SO_2 AAAQS demonstrations per EPA policy.[26] The Department is imposing AGDC's 500 hr/yr assumption as an ambient condition to protect the annual AAAQS/increments, as well as the one-hour NO_2 and SO_2 AAAQS.

5.7.5. Sulfur Compound Emissions

SO_2 emissions are directly related to the sulfur content of the fuels fired. AGDC assumed their liquid fuel-fired EUs fire fuel with a sulfur content of 15 parts-per-million by weight (ppmw). They assumed their fuel gas-fired EUs fire fuel with a total sulfur content of 16 parts-per-million by volume (ppmv). The Department is imposing these assumptions as permit conditions to protect the SO_2 AAAQS/increments

5.7.6. Stack Heights

The compression turbine (**EUs 1 through 6**) stacks and the elevated low-pressure flare (**EU 20**) release will be taller than the exhaust stacks used at the other Nikiski-area stationary sources. Moreover, the assumed stack heights for the power generation turbines (**EUs 7 through 10**), while comparable to those from select nearby sources[27], are significant enough to spatially influence ambient impacts from the Liquefaction Plant. The release heights used in the modeling analysis comply with the stack height requirements listed in 40 CFR 52.21(h) and 18 AAC 50.045(e) – (f), but they are, nevertheless, noteworthy in terms of pollutant transport and building downwash impacts; see the related discussion in Section 5.11 of this report with regard to the latter.

[26] EPA Memorandum from Tyler Fox to Regional Air Division Directors, *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard;* 1 March, 2011.

[27] E.g. Tesoro's Kenai Refinery and the Agrium/Nutrien Kenai Nitrogen Plant.

AGDC assumed a physical release height of 63.4 m for the low-pressure flare, which is generally taller than that for comparable units and influential in terms of its diminished interface of the exhaust plume with nearby structures. Similarly, they used modeled stack heights of 64.0 m and 45.7 m for the compression turbines and power generation turbines, respectively. While significant, these assumptions are consistent with the Good Engineering Practice (GEP) requirements in 40 CFR 52.21(h)(1)(i) and 18 AAC 50.045(f)(1).

The Department is imposing the assumed stack heights for the EUs described above as a minimum height requirement to protect the AAAQS and increments. The modeled stack heights are reiterated below in Table 6. The assumed stack heights for the remaining EUs are either within expectations or anticipated to have designs that would maximize downwash, thus obviating the need for explicit stack height conditions.

Table 6. Minimum Stack Height Requirements

EU	Model ID	Description	Min. Stack Height (m)
1 - 6	TURB1 TURB2 TURB3 TURB4 TURB5 TURB6	Treated Gas Compressor Turbines	64.0
7 - 10	TRB_GEN1 TRB_GEN2 TRB_GEN3 TRB_GEN4	Power Generation Turbines	45.7
20	LP_FLARE LP_MAX	Elevated Low-pressure Flare	63.4

5.7.7. Horizontal/Capped Stacks

Capped stacks or horizontal releases generally lead to higher impacts in the immediate near-field than what would occur from uncapped, vertical releases. The presence of non-vertical stacks or stacks with rain caps therefore requires special handling in an AERMOD analysis; see the related discussion in Section 5.8.2 of this report.

AGDC characterized all of the Liquefaction Plant EUs as having uncapped, vertical releases. This is a typical stack design for combustion turbines, however, RICE units, such as AGDC's emergency firewater pump (**EU 11**) and auxiliary air compressor (**EU 12**), can have horizontal releases. Since the impacts from horizontal stacks are typically greater than the impacts from stacks with vertical, uncapped discharges, the Department is imposing AGDC's vertical, uncapped assumption for the two RICE, EUs 11 and 12, as an ambient air condition.

5.8. Off-Site Emissions and Stack Parameters

AGDC explicitly modeled the following off-site sources in their cumulative AAAQS/increment analyses:

- Nutrien/Agrium Kenai Nitrogen Operations Plant and Loading Terminal;
- Conoco Phillips Kenai LNG Facility;
- Homer Electric Association Bernice Lake Power Plant;
- Homer Electric Association Nikiski Generation Plant;
- Tesoro Kenai Pipeline Marine Loading Terminal; and
- Tesoro Refinery

They used relevant information from a separate application for a PSD Construction Permit[28] and the Department's 2011 emissions inventory to develop their off-site emission rates and stack parameters for the Liquefaction Plant cumulative impact analyses. For the associated marine vessels, also included in said cumulative analyses, AGDC relied upon Cook Inlet inventory data from 2010, scaled upward for area development, and release parameters assumed to match those of the Liquefaction Plant Marine Terminal vessels. AGDC used the actual emission rates allowed under the Guideline in the annual assessments. The modeled short-term emission rates, along with the characterization of several horizontal/capped stacks, warrants discussion.

5.8.1. Short-Term Emission Rates

Some off-site EUs are authorized to operate continuously on an annual basis. As such, AGDC characterized these EUs with unrestricted emission rates in their ambient demonstrations with one-hour, three-hour, and 24-hour averaging periods. This approach is consistent with Table 8-2 of the 2005 Guideline.

In contrast to the former, however, select off-site units operate intermittently, such as emergency generators and fire water pumps. These units typically have annual operating limits measured in the hundreds-of-hours. The annual emission rates may, therefore, be used to characterize these EUs in the one-hour NO_2 and one-hour SO_2 AAAQS demonstrations per EPA guidance; see Section 5.7.4 of this report. AGDC appropriately used this approach in their one-hour NO_2 and one-hour SO_2 AAAQS demonstrations.

The Department notes that it does not have a written policy germane to the characterization of intermittently operated EUs within an off-site inventory. This lack of policy presents an especially salient challenge when reviewing the modeled characterization of intermittently operated units during short-term averaging periods for which no EPA guidance exists[29]. The Department understands that AGDC did not want to use an overly conservative characterization of those units subject to restricted

[28] Submitted in support of the Nutrien/Agrium Kenai Nitrogen Operations facility.
[29] E.g. the probabilistic 24-hour PM-2.5 standard and other short-term deterministic AAAQS/increments.

operation. However, employing a scaled annual emission rate to characterize short-term AAAQS/increment demonstration units may understate what occurs during those averaging periods. For example, an annual limit of 100 hr/yr, such as that assumed for units subject to a periodic reliability check, is equivalent to a scaled emission rate of about 16 minutes of operation per-day; it is likely such a check would entail greater daily operation in practice.

To generally address the former concerns, the Department more closely examined the reported emissions inventory information for select intermittently operated off-site EUs. It noted that reported information may suggest a more conservative approach exists to characterize the emissions from these EUs during short-term AAAQS/increment demonstrations. However, this difference is sufficiently small such that it is reasonable to anticipate no meaningful impact to the estimated ambient impacts would occur. See the Department's associated findings in the Modeling Report for AGDC's GTP stationary source for detail relevant to this topic.

5.8.2. Characterization of Off-site Horizontal Stacks

As noted in Section 5.7.7 of this report, the presence of non-vertical stacks or stacks with rain caps requires special handling in an AERMOD analysis. While all of the Liquefaction Plant EUs have uncapped, vertical releases, several of the off-site EUs have either horizontal or capped releases.

EPA describes the proper approach for characterizing capped and horizontal stacks in their *AERMOD Implementation Guide*.[30] EPA has also developed an option in AERMOD that will revise the release parameters according to their guidance for any stack identified as horizontal (using the POINTHOR keyword) or capped (using the POINTCAP keyword).

AGDC used the POINTHOR and POINTCAP options to characterize the off-site EUs with horizontal/capped stacks. The option is an approved modeling technique under the 2016 version of the Guideline, but it is considered as an alternative technique under the 2005 version that the Department used for its review; see Section 2.4.3 of this report. AGDC's use of the POINTHOR option therefore requires case-specific approval under 18 AAC 50.215(c).

5.8.2.1 Technical Justification

18 AAC 50.215(c)(1) requires a demonstration that the alternative approach is more appropriate than the preferred air quality model. EPA provided the required demonstration when they promulgated the 2016 version of the Guideline. A summary of this demonstration may be found in the 17 January, 2017 Federal Register notice of the 2016 Guideline (see 82 FR 5182).

30 *AERMOD Implementation Guide* (EPA-454/B-18-003); April 2018.

5.8.2.2 EPA and Department Approval

18 AAC 50.215(c)(2) requires approval of an alternative modeling technique from the EPA Regional Administrator and the Commissioner's designee. The Commissioner delegated the responsibility for approving alternative modeling methods to the Air Permits Program (APP) Manager on 3 June, 2008.

AGDC noted their desire to use the POINTHOR and POINTCAP options for the cumulative impact analyses in their PSD modeling protocol. The APP Manager approved AGDC's request on 17 November, 2017. R10 approved the request on 12 December, 2017.

5.8.2.3 Public Comment

In addition to complying with the Department's modeling requirements in 18 AAC 50.215(c), PSD applicants must also comply with the PSD modeling requirements in 40 CFR 52.21(l). 40 CFR 52.21(l)(2) says the use of a non-Guideline modeling technique, "*must be subject to notice and opportunity for public comment*." Therefore, the Department is soliciting public comment regarding AGDC's use of the POINTHOR and POINTCAP algorithms in the public notice of the preliminary construction permit.

5.9. Shoreline Fumigation Analysis

Section 7.2.8 of the Guideline describes various complex wind scenarios that may need to be addressed in an air quality modeling analysis. One of those scenarios, shoreline fumigation, warranted assessment in the Liquefaction Plant analysis.

Fumigation "…*occurs when a plume that was originally emitted into a stable layer is mixed rapidly to ground-level when unstable air below the plume reaches plume level*." [31] The phenomena can cause high ground-level concentrations. In coastal areas, fumigation can occur when a plume that is emitted from a tall stack interacts with the "*thermal internal boundary layer*" (TIBL) at some downwind distance. The phenomena is illustrated in Figure 5-6 of Modeling Report, provided as Appendix D to Resource Report 9.

The Liquefaction Plant stationary source will be located on the eastern shore of Cook Inlet. The physical release heights of select EUs at the source, and exhaust plumes in the case of flaring, approach 100 m in height when both the stack and base elevations are considered. The aforementioned factors, therefore, warrant a shoreline fumigation analysis.

AGDC used the Shoreline Dispersion Model (SDM) to evaluate the impacts of fumigation from the Liquefaction Plant's tall stacks on air quality. Their approach generally entailed an additive process by which SDM-predicted results were combined with their AERMOD output; additional detail on their approach is included in Section 5.8 of AGDC's Modeling

[31] Section 4.5.3 of EPA's *Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised* (EPA-454/R-92-019)

Report, provided as Appendix D to Resource Report 9. The Department finds that the potential overstatement of ambient impacts inherent in this approach offers a conservative basis to estimate the aggregate of both in the case of the Liquefaction Plant stationary source. The Department notes that, while the SDM would typically require approval for use as an alternative model under the Guideline, AGDC's use of the tool did not. The reasoning for this is predicated upon its use as a supplement to AERMOD rather than a replacement as discussed in an e-mail[32] between EPA Region 10 and the Department.

5.10. Pollutant Specific Considerations

The following pollutants warrant additional discussion.

5.10.1. Ambient NO_2 Modeling

The NOx emissions from combustion sources are partly nitric oxide (NO) and partly NO_2. After the combustion gas exits the stack, additional NO_2 can be created due to atmospheric reactions. Section 5.2.4 of the Guideline describes a tiered approach for estimating the resulting annual average NO_2 concentration, ranging from the simplest but very conservative assumption that 100 percent of the NO is converted to NO_2, to other more complex methods. These approaches are also generally applicable in modeling the one-hour NO_2 impacts.

AGDC used ARM2 to estimate their ambient NO_2 concentrations, as previously noted in Section 5.2.1 of this report. ARM2 is an EPA-approved modeling technique under the 2016 version of the Guideline, but it is considered as an alternative technique under the 2005 version; see Section 2.4.3 of this report. ARM2, therefore, requires case-specific approval under 18 AAC 50.215(c). Applicants also have the option of using a non-default MAR. Each of these aspects is further discussed below.

5.10.1.1 Procedural Requirements

As previously discussed in Section 5.8.2.1 of this report, 18 AAC 50.215(c)(1) requires a demonstration that the alternative approach is more appropriate than the preferred air quality model. EPA provided the required demonstration when they promulgated the 2016 version of the Guideline (see 82 FR 5182).

18 AAC 50.215(c)(2) requires EPA Region 10 and Department approval of the alternative modeling technique. The Air Permits Program Manager approved AGDC's request to use ARM2 on 20 November, 2017, and Region 10 approved the request on 12 December, 2017.

[32] Email from Jay McAlpine (EPA R10) to Alan Schuler (Department) and George Bridgers (EPA), *RE: Quick update on our status for Alaska LNG*; 6 December, 2017.

5.10.1.2 Minimum Ambient Ratio

ARM2 uses empirically derived ambient ratios of NO_2/NOx conversion in its application of a ratio for modeled NOx concentrations. The default upper- and lower-bounds for this applied ratio in a model are 0.9 and 0.2, respectively.

AGDC used the default lower-bound of 0.2 in their analysis. Their basis for the use of this ratio is predicated upon the assertion it is representative of in-stack conversion for the EUs dominating impacts at the Liquefaction Plant. They further assert that, while select units may be characterized by higher conversion ratios, those most culpable for one-hour NO_2 impacts are likely to possess sub-0.2 ratios. In further support of their use of the minimum ratio, AGDC cites EPA guidance[33] indicating that full-conversion results within 150 to 200 parts-per-billion by volume (ppbv) are anticipated to be conservative when using ARM2, irrespective of the assumed ratio. AGDC's Tier 1 results, as reported in their application, offer a full-conversion NO_2 impact of approximately 134 ppbv.

The Department is aware of source test data that suggest turbines, flares, and RICE equipped with catalyzed diesel particulate filters may possess in-stack ratios above 0.2. Moreover, AGDC's modeling assumptions for the GTP stationary source, which employ the Plume Volume Molar Ratio Method (PVMRM) to estimate ambient NO_2 impacts, reflect a generally higher set of conversion ratios for similar EUs. A Departmental review of source-group categorized impacts and model outputs, however, alongside the relative conservatism of ARM2 vs PVMRM estimated impacts, is sufficient to find AGDC's use of ARM2 and its assumed default ratios appropriate on a case-specific basis for the Liquefaction Plant stationary source.

5.10.2. PM-2.5

PM-2.5 is either directly emitted from a source or formed through chemical reactions in the atmosphere (secondary formation) from other pollutants (NOx and SO_2).[34] AERMOD is an acceptable model for performing near-field analyses of the direct emissions, but EPA has not developed a near-field model that includes the necessary chemistry algorithms for estimating the secondary impacts. They instead issued guidance as to how secondary formation could be accounted for under the 2005 version of the Guideline.[35]

EPA noted that the maximum direct impacts and the maximum secondary impacts from a stationary source "*…are not likely well-correlated in time or space*", i.e., they will likely occur in different locations and at different times. This difference occurs because secondary PM-2.5 formation is a complex photochemical reaction that requires a mix of

[33] EPA Memorandum from OAQPS, *Clarification on the Use of AERMOD Dispersion Modeling for Demonstrating Compliance with the NO2 National Ambient Air Quality Standard*; 30 September, 2014.
[34] The NOx and SO_2 emissions are also referred as "precursor emissions" in a PM-2.5 assessment.
[35] *Guidance for $PM_{2.5}$ Permit Modeling* (EPA-454/B-14-001); May 2014.

precursor pollutants in sufficient quantities for significant formation to occur. As such, it is highly unlikely that there is sufficient time for the reaction to substantively occur within the immediate near-field, which is where the maximum direct impacts from the Liquefaction Plant EUs occur.

AGDC used representative ambient monitoring data to address their near-field secondary PM-2.5 formation from off-site sources in comport with EPA guidance; see the associated discussion in the Department's Modeling Report for the GTP stationary source for relevant detail. In supplemental support of the former approach, AGDC also evaluated the potential impact from secondary PM-2.5 formation using the CALPUFF model and its POSTUTIL post-processor. The analytical methodology of this approach generally entails an examination of precursor emissions and their anticipated PM-2.5 impacts. A more detailed discussion of this approach is presented in Section 8.5 of AGDC's Modeling Report, provided as Appendix D to Resource Report 9. The Department finds that this approach is appropriate to generally characterize the impact of secondary PM-2.5 formation at the Liquefaction Plant stationary source.

5.11. Downwash

Downwash refers to the situation where local structures influence the plume from an exhaust stack. Downwash can occur when a stack height is less than GEP, which is defined in 18 AAC 50.990(42). It is a consideration when there are receptors relatively near the applicant's structures and exhaust stacks.

EPA developed the "Building Profile Input Program – PRIME" (BPIPPRM) program to determine which stacks could be influenced by nearby structures and to generate the cross-sectional profiles needed by AERMOD to determine the resulting downwash. AGDC used the current version of BPIPPRM, version 04274, to determine the building profiles needed by AERMOD for the Liquefaction Plant EUs.

The Department used a proprietary 3-D visualization program to review AGDC's modeled characterization of the exhaust stacks and structures. Their characterization of the Liquefaction Plant EUs are representative of the layout shown in Figure 5-5 of Appendix D to Resource Report 9. AGDC's characterization of the off-site sources and/or building configurations also appear to represent the facility layouts on file from previous submissions. BPIPPRM indicated that the GTP exhaust stacks are within the GEP stack height requirements.

5.12. Ambient Air Boundary

The AAAQS and increments only apply in *ambient air* locations, which has been defined by EPA as, "…*that portion of the atmosphere, external to buildings, to which the general public has access*." [36] Applicants may, therefore, exclude areas that they own or lease from

[36] The term "ambient air" is defined in 40 CFR 50.1. The Alaska Legislature has also adopted the definition by reference in AS 46.14.90(2).

their ambient demonstration if public access is "*precluded by a fence or other physical barrier*."[37]

AGDC used the proposed fenced perimeter around the Liquefaction Plant as an ambient air quality boundary for the on-shore facility area. They also excluded the marine vessel loading berths and trestle areas from ambient air assuming a 500-foot stand-off distance predicated upon reasonable and enforceable safety requirements. The former element of AGDC's approach offers a clear means to preclude the public from ambient air. The latter element of this approach, while not supported by explicit and quantifiable air quality guidance, is rooted in practical precedent. The Department's discussion in the Ambient Boundary section of its Modeling Report for PacRim Coal, LLC's Chuitna Project, Minor Permit AQ0957MSS03, offers relevant detail regarding the exclusion of vessel loading activities from ambient air. AGDC's approach to exclude select areas from ambient air is appropriate for the Liquefaction Plant ambient analysis.

5.13. Receptor Grid

A dispersion model will calculate the concentration of the modeled pollutant at locations defined by the user. These locations are called receptors. Designated patterns of receptors are called receptor grids.

AGDC described their receptor grid in Section 5.4 of Appendix D to Resource Report 9. In summary, AGDC used a Cartesian receptor grid of decreasing resolution with distance from the ambient boundary for their project impact analysis. The modeled receptor resolutions are:

- 25 m resolution along both the Liquefaction Plant fence line and off-site facility fence lines;
- 25 m resolution along the edge of AGDC's 500 foot marine vessel and trestle exclusion zone;
- 25 m resolution from the previous boundaries to a outward distance of 200 m;
- 50 m resolution from 200 m to an outward distance of 500 m;
- 100 m resolution from 500 m to an outward distance of 1 km;
- 250 m resolution from 1 km to an outward distance of 2.5 km;
- 500 m resolution from 2.5 km to an outward distance of 5 km;
- 1 km resolution from 5 km to an outward distance of 10 km; and
- 2 km resolution from 10 km to an outward distance of 20 km.

[37] EPA has written a number of guidance documents regarding ambient air issues which may be found in their Modeling Clearinghouse Information Storage and Retrieval System (http://cfpub.epa.gov/oarweb/MCHISRS/). The documents routinely use the phrase "fence or other physical barrier" when discussing an acceptable means for precluding public access at onshore locations. The phrase originated in a December 19, 1980 letter from EPA Administrator Douglas Costle to Senator Jennings Randolph.

AGDC's receptor grid has sufficient resolution and coverage to determine the maximum impacts. The maximum impacts generally occur near the Liquefaction Plant facility.

5.14. Off-Site Impacts

The air quality impact from natural and regional sources, along with long-range transport from far away sources, must be accounted for in a cumulative AAAQS demonstration. The increment consuming impact from nearby off-site anthropogenic sources must likewise be accounted for in a cumulative increment demonstration. The approach for incorporating these impacts must be evaluated on a case-specific basis for each type of assessment and for each pollutant.

The off-site facilities enumerated Sections 5.1 and 5.8 of this report are close enough to have significant concentration gradients in the vicinity of the Liquefaction Plant. AGDC, therefore, included these sources in their cumulative AAAQS/increment analyses. They used ambient NO_2, SO_2, and CO data collected during their pre-construction monitoring effort, and PM-10, PM-2.5, and O_3 data collected by Nutrien/Agrium for the nearby Kenai Nitrogen Operation stationary source, to represent the impacts from all other sources in their cumulative analyses not explicitly modeled; see Section 4 of this report for details of these data collection efforts. In summary, AGDC's selection of off-site sources, and the contemporaneous superposition of PSD-quality background data, are sufficient to represent the air quality impacts from natural and anthropogenic sources in the project area.

5.15. Modeled Design Concentrations

EPA allows applicants to use modeled concentrations that are consistent with the form of the given standard or increment as their design concentrations. The highest concentrations must generally be used when comparing the modeled impacts to the SILs. However, the multi-year average of the highest concentrations may be used when comparing the one-hour NO_2, one-hour SO_2, 24-hour PM-2.5, and annual PM-2.5 impacts to the SILs – for purposes of demonstrating compliance with the AAAQS.[38] AGDC used the modeled concentrations that are consistent with the above description. The design concentrations used in AGDC's cumulative modeling analyses to demonstrate compliance with the AAAQS and Class II increments are summarized in Table 7.

Table 7. AGDC's Approach for Determining the Modeled Design Concentrations

Pollutant	Avg. Period	AAAQS	Class II Increment
NO_2	one-hour	h8h	--
	Annual	HY	HY
PM-10	24-hour	h6h	h2h
	Annual	--	HY

38 The maximum value from any year must be used for the other pollutants and averaging periods, and when comparing the 24-hour PM-2.5 and annual PM-2.5 impacts to the SILs for purposes of demonstrating compliance with the Class II increments.

PM-2.5	24-hour	h8h	h2h
	Annual	MA	HY
SO_2	one-hour	h4h	--
	three-hour	h2h	h2h
	24-hour	h2h	h2h
	Annual	HY	HY
CO	one-hour	h2h	--
	eight-hour	h2h	--

Table Notes:

h2h = the maximum high second-high concentration from any year.

h4h = the multi-year average of the high fourth-high daily maximum one-hour concentrations.

h6h = the high sixth-high 24-hour concentration over five years.

h8h = high eighth-high. For purposes of one-hour NO_2, the h8h is the five-year average of the high, eighth-high of the daily maximum one-hour NO_2 concentrations. For purposes of 24-hour PM-2.5, the h8h is the five-year average of the high, eighth-high of the 24-hour PM-2.5 concentrations.

HY = highest annual average from any year.

MA = highest multi-year average of the annual concentrations at a given receptor.

-- = there is no AAAQS/increment (as applicable) for this pollutant/averaging period.

6. NEAR-FIELD MODELING RESULTS AND DISCUSSION

The maximum project impacts are presented in Table 8. The SIL for each pollutant and averaging period is also presented for comparison. The maximum impacts exceed the applicable SIL for most pollutants and averaging periods; the annual SO_2 is the exception. Therefore, the Liquefaction Plant emissions will not cause or contribute to a violation of the annual SO_2 AAAQS or Class II increments.

Table 8. Maximum Project Impacts Compared to the SILs

Pollutant	Avg. Period	Max. Modeled Conc. ($\mu g/m^3$)	SIL ($\mu g/m^3$)
NO_2	one-hour	140.1	8
	Annual	8.4	1
SO_2	one-hour	57.5	8
	three-hour	39.6	25
	24-hour	17.1	5
	Annual	0.11	1
PM-2.5 (multi-year avg.)	24-hour	3.6	1.2
	Annual	0.38	0.3

PM-2.5 (max. impact from any year)	24-hour	4.8	1.2
	Annual	0.43	0.3
PM-10	24-hour	24.7	5
	Annual	2.7	1
CO	one-hour	2,721	2,000
	eight-hour	1,071	500

Table Note: The multi-year average of the maximum PM-2.5 impacts may be compared to the PM-2.5 SILs for purposes of demonstrating compliance with the PM-2.5 AAAQS. However, the maximum PM-2.5 impact from any year must be compared to the PM-2.5 SILs for purposes of demonstrating compliance with the PM-2.5 increments. (See Section 5.15 of this report.)

The results from the cumulative AAAQS analyses are presented in Table 9. The background concentrations, total impact, and AAAQS are also shown. All of the total impacts are less than the AAAQS.

Table 9. Maximum Impacts Compared to the AAAQS

Pollutant	Avg Period	Modeled Design Conc. ($\mu g/m^3$)	Max. one-hour Fumigation Conc. ($\mu g/m^3$)	Bkgd Conc. ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	AAAQS ($\mu g/m^3$)
NO_2	one-hour	149.5	Included	32.3	**181.8**	188
	Annual	20.4	34.1	2.6	**57.1**	100
PM-10	24-hour	23.9	5.0	40	**68.9**	150
PM-2.5	24-hour	6.4	5.0	12	**23.4**	35
	Annual	2.8	5.0	3.7	**11.4**	12
CO	one-hour	2,721	78.3	1,145	**3,945**	40,000
	eight-hour	1,071	78.3	1,145	**2,294**	10,000
SO_2	one-hour	63.4	5.7	5.0	**74.1**	196
	three-hour	50.6	5.7	5.0	**61.3**	1,300
	24-hour	32.0	5.7	2.4	**40.1**	365

Table Note: The one-hour NO_2 background concentration is included in the modeled concentration.

The results from the cumulative Class II increment analysis are presented in Table 10. The modeled design concentrations are less than the Class II increment for all pollutants and averaging periods.

Table 10. Maximum Modeled Impacts Compared to the Class II Increments

Pollutant	Avg. Period	Modeled Design Conc. (μg/m³)	Max. one-hour Fumigation Conc. (μg/m³)	Total Impact (μg/m³)	Class II Increment (μg/m³)
NO_2	Annual	12.5	Included	12.5	25
PM-10	24-hour	24.7	5.0	29.7	30
	annual	2.7	5.0	7.7	17
PM-2.5	24-hour	8.7	Included	8.7	9
	Annual	1.3	Included	1.3	4
SO_2	three-hour	39.6	5.7	45.4	512
	24-hour	17.5	5.7	23.3	91

7. CLASS I ANALYSES

In accordance with 40 CFR 52.21(p), PSD applicants must perform a Class I Impact Analysis, for stationary sources that may affect a Class I area. As broached in Section 2.1, the Class I areas nearest the Liquefaction Plant are Tuxedni, managed by the US FWS, and Denali, managed by the NPS. Tuxedni is located 86 km to the south, and Denali approximately 183 km to the north. The following describes AGDC's approach with regard to the Class I increment and AQRV.

7.1. Class I Increment Analysis

There are no Class I areas within 50 km of the Liquefaction Plant. The nearest Class II Sensitive area, Kenai National Wildlife Refuge (Kenai NWR), however, is situated approximately 10 km distant. AGDC, nevertheless, performed near-field analyses of their increment impacts using AERMOD. The source-only and cumulative results, provided previously in this report, do not suggest meaningful ambient concentration gradients attributable to the Liquefaction Plant exist beyond the immediate near-field of the stationary source. Moreover, all results indicate estimated ambient concentrations within the modeled areas of concern fall below the respective increments.

AGDC used the EPA's approved CALPUFF model, along with its associated pre- and post-processing tools, to evaluate their far-field impacts at the Tuxedni and Denali Class I areas. They additionally evaluated impacts at several Class II Sensitive areas[39] within their modeled domain. A detailed discussion germane to AGDC's selection and development of far-field model inputs and outputs is provided in Section 6 of their Modeling Report, included as Appendix D to Resource Report 9. AGDC's far-field model results, both source-only and cumulative, indicate estimated ambient concentrations within the modeled areas of

[39] The Class II Sensitive areas subject to evaluation include the Kenai NWR, Chugach National Forest, Lake Clark National Park and Preserve, Kenai Fjords, and Kodiak National Wildlife Refuge.

concern fall below the respective increments; no violations of the NAAQS/AAAQS are seen.

7.2. Class I AQRV Analysis

AGDC performed a near-field assessment, to evaluate the impact of non-collocated plumes as compared to background viewing, and a far-field assessment, with regard to impacts to regional views.

There are no Class I areas within 50 km of the Liquefaction Plant. AGDC, nevertheless, evaluated plume visibility at the Kenai NWE[40], which is situated within 50 km, using EPA's VISCREEN model, a screening-level plume visibility tool. The VISCREEN model, drawing upon user-provided environmental variables, provides an analytical estimation of visual impairment through both the plume contrast and plume perceptibility parameters. Details of AGDC's assumed near-field model variables and VISCREEN-observed EU plume combinations is provided in Sections 6.6 and 7.2.4.1 of their Modeling Report, included as Appendix D to Resource Report 9. The results of AGDC's VISCREEN analysis at the Kenai NWR indicate that nearly all modeled visibility parameters fall below their associated criteria. The exceptions include:

- A slight deviation from both criteria for the compressor turbine plumes, subject to sky background and backward scatter, at the closest park boundary observer location; and
- An increase in the perceptibility criteria for the compressor turbine plumes, subject to terrain background and forward scatter, at both the closest park boundary and Skilak Lake observer locations.

It is reasonable to consider the former deviances negligible given representative-to-conservative model inputs and the level of uncertainty inherent at this resolution of modeled result. Moreover, the relative isolation of these estimated deviances at a Class II Sensitive area is not sufficient to warrant further regulatory inquiry, *ceteris paribus*. Therefore, the Department finds AGDC's modeled results sufficient to provide a reasonable estimation of immaterial near-field visibility impacts.

AGDC used the EPA's approved CALPUFF model, along with its associated pre- and post-processing tools, to evaluate their far-field impacts at the nearest Class I areas. They also included impacts at several Class II Sensitive areas situated within their modeling domain. Their CALPUFF evaluation included assessments of ambient concentration, visibility, and acidic deposition. A detailed discussion germane to AGDC's selection and development of far-field model inputs and outputs is provided in Sections 6, 7.2.4.2, and 7.2.4.3 of their Modeling Report, included as Appendix D to Resource Report 9.

AGDC's model-estimated source-only impacts to both Class I and Class II Sensitive areas, in terms of regional haze and visibility degradation, fall below the five-percent extinction

[40] The Kenai NWR is designated as a Class II Sensitive area for the purposes of air quality assessments.

threshold at all areas evaluated, save slight exceedances at Lake Clark National Park in model years 2003 and 2004. When considering a cumulative analysis, however, the model predicts exceedances of the 10-percent extinction criteria at all locations. The Department understands that these cumulative values may be compelling when considered in the absence of additional information. However, AGDC's source-only results suggest there is no cause for regulatory concern at the former areas with regard to significant visibility impairment attributable to operation of the Liquefaction Plant as proposed. Furthermore, mode uncertainty and conservative operational assumptions suggest estimated impacts attributable to the Liquefaction Plant may be overstated. Therefore, the Department finds AGDC's modeled results sufficient to provide a reasonable estimation of immaterial far-field visibility impacts.

AGDC's source-only deposition analysis indicates sulfur and nitrogen flux results above the respective deposition analysis thresholds (DATs) at several locations; Denali is the only Class I area among the former. Their cumulative deposition analysis yield results below the DAT at all locations. The Department notes that among those locations with higher source-attributable estimated deposition impacts, only sulfur appears to boast impacts that are meaningfully above the DATs while nitrogen remains marginally above said thresholds. The Department notes that AGDC's position regarding an in-situ potential for "sweeter" than modeled pipeline-quality fuel gas and conservative operational assumptions would likely obviate the sulfur deposition concerns at the Class II Sensitive areas modeled. It further notes that said conservativism of operational assumptions, largely predicated upon AGDC's greater than anticipated 'normal' modeled operational scenario, would similarly mitigate their source-attributable nitrogen deposition impacts. Therefore, the Department finds AGDC's modeled results sufficient to provide a reasonable estimation of immaterial acidic deposition impacts.

8. OZONE IMPACTS

As discussed in Section 1 of this report, VOC is a triggered PSD-pollutant for the Liquefaction Plant project. There is AAAQS for VOC, but its emissions, and those of NOx, can form O_3, which does have an AAAQS. AGDC was, therefore, required to demonstrate compliance with the O_3 AAAQS per 40 CFR 52.21(k).

O_3 is not usually emitted directly into the air. It is instead created in the atmosphere through chemical reactions between NOx and VOC in the presence of sunlight. It is inherently a regional pollutant, the result of chemical reactions between emissions from many NOx and VOC sources over a period of hours or days, and over a large area.

The 2005 version of the Guideline does not list a recommended model for assessing the O_3 impact from an individual stationary source. Qualitative approaches are instead generally used to meet the 40 CFR 52.21(k) ambient demonstration requirement.

AGDC provided a background discussion regarding O_3 formation in Section 8 of the Liquefaction Plant Modeling Report, provided as Appendix D to Resource Report 9. The discussion includes a trajectory analysis for days with "elevated" ozone concentrations using the HYSPLIT model. They also discussed several lower-48 Photochemical Grid Model (PGM) ozone analyses, and what the findings could mean with respect to the Liquefaction Plant project.

The Department did not take the time to review AGDC's trajectory analysis or PGM discussion noting the following aspect of their O_3 demonstration. AGDC provided an analytical discussion and tabular data in their response to the Department's 17 January, 2018 Modeling Protocol approval. This information is provided in Attachment 3 to Resource Report 9. The discussion and data, in conjunction with the associated conceptual methodology observed by the Department in its Modeling Report for GTP, suggest the Liquefaction Plant project is not anticipated to cause or contribute to a violation of the eight-hour O_3 AAAQS.

9. ADDITIONAL IMPACT ANALYSES

PSD applicants must assess the impact from the proposed project and associated growth on visibility, soils, and vegetation, per 40 CFR 52.21(o) – *Additional Impact Analyses*. AGDC provided their additional impact analyses in Attachment 10 to Resource Report 9. The Department's findings regarding their analyses are reported below.

9.1. Associated Growth Analysis

40 CFR 52.21(o)(2) requires PSD applicants to "*provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source or modification*." AGDC does not expect industrial or commercial growth in the immediate vicinity of the Liquefaction Plant as it is planned to fit within the current area infrastructure. With respect to employment, AGDC stated that they anticipate the eventual creation of 300 jobs. While this would lead to some residential growth, the number represents approximately two-percent of the current area population based upon 2010 U.S. Census figures. As such, the concomitant increase in emissions associated with residential growth would likely yield insignificant impacts on soils, vegetation, and visibility. The Department, therefore, finds AGDC's assessment reasonable for the Liquefaction Plant.[41]

9.2. Visibility Impacts

PSD applicants must assess whether the emissions from their stationary source, including associated growth, will impair visibility. Visibility impairment means any humanly perceptible change in visibility, such as visual range, contrast, or coloration, from that which would have existed under natural conditions. Visibility impacts can occur as visible plumes, i.e., "plume blight," or in a general, area-wide reduction in visibility, also known as "regional haze". Alaska does not have standards for plume blight. For Class I areas, the

[41] AGDC did not include the Pipeline Stations and Gas Treatment Plant in their Associated Growth Analyses since those stationary sources will not be located in the same area as the Liquefaction Plant. As previously noted in Section 5.6.3 of this report, the ambient impacts associated with each of those stationary sources will be assessed, as warranted, under the permit requirements for that stationary source.

Federal Land Manager provides the desired thresholds. There are no established thresholds for Class II areas. The typical tool for assessing plume blight is EPA's VISCREEN model.

The maximum range of VISCREEN is 50 km. When Class I areas lie beyond that range, as in the case at hand, the Department recommends that the applicant use the 50 km maximum range as the source to observer distance. This approach provides the upper bound of the potential plume blight impacts at more distance locations. This same distance (50 km) would also be used as the "nearest" source to boundary distance per page 24 of EPA's *Workbook for Plume Visual Impact Screening and Analysis (Revised)*.[42]

Since there are no Class II visibility thresholds, VISCREEN compares the visibility impacts to the Class I thresholds. VISCREEN provides results for impacts located inside a Class I area and for impacts located outside a Class I area. The latter is used in situations where there is an "integral vista." In situations where there are no integral vistas, applicants only need to use the results for impacts located inside a Class I area. Alaska only has two integral vistas, both of which are associated with Denali National Park. Since the integral vistas are well beyond the 50 km range of VISCREEN, the Department informed AGDC that they only needed to report the "inside" results. A discussion regarding AGDC's visibility analysis is presented in Section 7.2 of this report. The Department did not require AGDC to conduct a more rigorous visibility analysis since there are no plume blight thresholds for Class II areas.

9.3. Soil and Vegetation Impacts

The ambient demonstration provided by applicants is typically adequate for showing that their air emissions will not cause adverse soil or vegetation impacts. Congress established "primary" NAAQS and "secondary" NAAQS in Section 109(b) of the Clean Air Act. The primary NAAQS protect public health, while the secondary NAAQS protect public welfare. Congress further stated in Section 302(h) of the CAA, "*All language referring to the effects of **welfare** includes, but is not limited to, effects on **soils**, water, crops, **vegetation**, …*" (emphasis added).The AAAQS and primary NAAQS are identical for each of the modeled pollutants. However, the annual PM-2.5 secondary NAAQS (15 $\mu g/m^3$) is less stringent than the annual PM-2.5 primary NAAQS/AAAQS (12 $\mu g/m^3$). Therefore, a modeling analysis that demonstrates compliance with the AAAQS also demonstrates compliance with the secondary NAAQS.

AGDC demonstrated that they can comply with the primary AAAQS. They summarized this information in Table 1 of Attachment 10 to Resource Report 9. Therefore, their ambient analysis generally demonstrates that they will not have adverse soil or vegetation impacts.

10. CONCLUSIONS

The Department concludes the following based on its review of AGDC's permit application and ambient demonstrations:

[42] *Workbook for Plume Visual Impact Screening and Analysis (Revised),* (EPA-454/R-92-023); October 1992.

1. AGDC's characterizations of the proposed exhaust stacks comply with the stack height and dispersion requirements described in 40 CFR 52.21(h) ***Stack Heights***.
2. AGDC's ambient demonstration satisfies the ***Source Impact Analysis*** requirements of 40 CFR 52.21(k). AGDC demonstrated that the NOx, SO_2, PM-10, PM-2.5, CO, and VOC emissions associated with operating the stationary source, within the restrictions listed in this report, will not cause or contribute to a violation of the NO_2, SO_2, PM-10, PM-2.5, CO, and O_3 AAAQS. They also demonstrated that the emissions will not cause or contribute to a violation of the NO_2, SO_2, PM-10, and PM-2.5 Class I or II increments.
3. AGDC appropriately used the models and methods required under 40 CFR 52.21(l) ***Air Quality Models***.
4. AGDC conducted their modeling analysis in a manner consistent with the Guideline, as required under 18 AAC 50.215(b)(1).
5. The 2018 to 2019 ambient pollutant data collected by AGDC at the project site, and 2013 to 2014 data collected by Nutrien/Agrium for the nearby Kenai Nitrogen Operation project, satisfies the ***Preapplication Analysis*** requirements of 40 CFR 52.21(m)(1).
6. AGDC provided the ***Additional Impact Analyses*** required under 40 CFR 52.21(o).

The Department developed permit conditions in Construction Permit AQ1539CPT01 to ensure AGDC complies with the AAAQS and Class II increments. These conditions are *summarized* as follows:

- To protect the NO_2, CO, PM-10, PM-2.5, and SO_2 AAAQS, and the NO_2, PM-10 and PM-2.5 Class II increments:

  Stack Configuration

  - Construct and maintain vertical, uncapped exhaust stacks for **EUs 11 – 12** and on all temporary construction RICE EUs. AGDC may use flapper-style rain covers, or other similar designs, that do not hinder the vertical momentum of the exhaust plume.

  Stack Heights

  - Construct and maintain exhaust stacks with release points above the base elevation that equals or exceeds the minimum height listed in Table 6 for that EU.
- To protect the one-hour and annual NO_2 AAAQS, the one-hour and annual SO_2 AAAQS, the annual PM-2.5 AAAQS, the annual NO_2 Class II increment, the annual SO_2 Class II increment, the annual PM-10 Class II increment, and the annual PM-2.5 Class II increment:
  - Limit the operation of **EUs 11 and 12** to 500 hr/yr.
- To protect the 24-hour PM-10 AAAQS, the 24-hour PM-2.5 AAAQS, and the annual PM-2.5 AAAQS during the construction phase:

    - Use the best management practices described in the permit to minimize the fugitve dust emissions from construction activities.
    - Install and operate one or more air quality monitoring stations to measure the actual PM-2.5 and PM-10 ambient concentrations. Take additional actions to reduce the fugitive dust emissions if the AAAQS become threatened.
- To protect the one-hour, three-hour, 24-hour, and annual SO_2 AAAQS; and the three-hour, 24-hour, and annual SO_2 Class II increments:
    - Limit the sulfur content of the liquid fuels fired to no greater than 15 ppmw; and
    - Limit the total sulfur content of the fuel gas fired to no greater than 16 ppmv.