ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
Air Permits Program

TECHNICAL ANALYSIS REPORT
for
Air Quality Control Construction Permit AQ0083CPT06

Agrium U.S. Inc.
Kenai Nitrogen Operations Facility

ESTABLISH KENAI NITROGEN OPERATIONS FACILITY

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Table of Contents

Abbreviations/Acronyms

AAC ....Alaska Administrative Code
AAAQS ....Alaska Ambient Air Quality Standards
Department ....Alaska Department of Environmental Conservation
BACT ....Best Available Control Technology
CFR. ....Code of Federal Regulations
DLN...............................Dry Low NOx
EPA ....Environmental Protection Agency
EU..................................Emission Unit
HAP...............................Hazardous Air Pollutant
MR&Rs ....Monitoring, Recording, and Reporting
NA ....Not Applicable
NESHAPS ....National Emission Standards for Hazardous Air Pollutants
NSPS ....New Source Performance Standards
ORL ....Owner Requested Limit
PSD................................Prevention of Significant Deterioration
PTE................................Potential to Emit
RICE, ICE ....Reciprocating Internal Combustion Engine, Internal Combustion Engine
SCR ....Selective Catalytic Reduction
SIP ....Alaska State Implementation Plan
TAR ....Technical Analysis Report
ULSD ....Ultra Low Sulfur Diesel
VE..................................Visible Emissions

Units and Measures

gal/hr.............................gallons per hour
g/kWh ....grams per kilowatt hour
g/hphr ....grams per horsepower hour
hr/day.............................hours per day
hr/yr ....hours per year
hp...................................horsepower
lb/hr ....pounds per hour
lb/MMBtu......................pounds per million British thermal units
lb/1000 gal.....................pounds per 1,000 gallons
kW ....kilowatts
MMBtu/hr......................million British thermal units per hour
MMscf/hr.......................million standard cubic feet per hour
ppmv..............................parts per million by volume
tpy..................................tons per year

Pollutants

CO ....Carbon Monoxide
CO_2e ....Carbon Dioxide Equivalent
GHG ....Greenhouse Gases
HAP...............................Hazardous Air Pollutant
NOx ....Oxides of Nitrogen
PM ....Particulate Matter
PM-2.5...........................Particulate Matter with an aerodynamic diameter not exceeding 2.5 microns
PM-10............................Particulate Matter with an aerodynamic diameter not exceeding 10 microns
SO_2 ....Sulfur Dioxide
VOC ....Volatile Organic Compound

1. INTRODUCTION

This Technical Analysis Report (TAR) provides the Alaska Department of Environmental Conservation's (Department's) basis for issuing Air Quality Control Construction Permit AQ0083CPT06 to Agrium U.S. Inc. (Agrium) for their Kenai Nitrogen Operations (KNO) Facility. The project triggers Prevention of Significant Deterioration (PSD) review under 18 AAC 50.306 for oxides of nitrogen (NOx), carbon monoxide (CO), total 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).

1.1 Description of Source

The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale.

1.2 Application Description

Agrium submitted an application for this project on October 24, 2013 and submitted several addenda through January 29, 2014. Agrium is requesting authorization to install and operate turbines, pumps, boilers, heaters, a reformer furnace, and reciprocating internal combustion engines to support production operations.

1.3 Project Description

There are two ammonia and two urea plants at Agrium's KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH_3) and carbon dioxide (CO_2). Feedstocks for the urea plant include CO_2 and NH_3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.

Ammonia Process

The ammonia production process involves the use of natural gas, steam, and air with the aid of catalysts, heat exchangers, and compressors. This overall process can be broken down into six distinct process steps:

- Gas preparation and reforming
- Shift conversion
- CO_2 removal
- Methanation and synthesis
- Refrigeration and liquefaction
- Atmospheric storage
- Product loading

In the first step, heated natural gas is prepared through the removal of sulfur. This gas is then mixed with steam, then heated and passed through the catalyst tubes in the Primary Reformer. Through the combination of increased temperature with the catalyst, the methane (CH_4) reacts with steam (H_2O) to form hydrogen (H_2), CO, and CO_2. Natural gas is fired in the burners of the Primary Reformer to supply the necessary heat to start this reaction process. The completion of the reforming reaction occurs in the Secondary Reformer, where compressed air is introduced to the gas stream. Some of the H_2 ignites to further increase the temperature and continue reforming the remaining (unreformed) CH_4.

After the reformer step, the gas stream must undergo a shift conversion reaction for the CO to be converted to CO_2. This step is accomplished in two catalyst beds that help CO and steam convert to CO_2 and H_2. Following shift conversion, CO_2 is removed from the gas stream in an absorber operation called the methyl diethanol amine (MDEA) Area. The MDEA solution removes the CO_2 from the gas stream and releases it for further use in the urea plant.

The gas stream now has primarily nitrogen (N_2) and H_2 with trace levels of CO and CO_2. The methanation reaction occurs over another catalyst bed (called the Methanator). It converts the CO and CO_2 to CH_4 through reaction with the H_2. With these impurities converted, the compressed and heated gas is then synthesized to NH_3 in another catalyst section in the Ammonia Converter. The gas stream from the converter is then processed through a series of coolers, separator vessels, refrigeration compressors, and flash drums to remove liquid ammonia for storage. The gas stream from this refrigeration and liquefaction loop is recycled back to the Ammonia Converter to maintain the correct process conditions. Also, a small amount of gas is purged from this recycling loop. This purge gas is treated in the Purge Recovery Unit, ammonia is removed, H_2 and N_2 are recycled, and the balance of CH_4 and inerts is used as supplemental fuel in the Primary Reformer.

Liquid ammonia is stored in tanks near atmospheric pressures and at low temperatures. The ammonia vapors that are flashed to gaseous form are collected, compressed, cooled, and liquefied for return to the storage tanks. Ammonia stored is either shipped offsite as product or sent to the urea plants for further processing.

Urea Process

The production of urea is accomplished by combining liquid NH_3 and CO_2 gas under pressure. Both of these feed streams are produced in the ammonia plant. The combined NH_3 and CO_2 form an intermediate compound called ammonium carbamate, which includes water. Urea is produced through a chemical dehydration of these molecules. The primary process steps in this production include the following:

- Compression and feed pumping
- Synthesis
- Evaporation
- Water treatment (recovery and reuse)
- Granulating
- Product storage and shipping

The first step in the urea process is to compress CO_2 to the desired reaction pressure through compressors which are steam driven. Liquid NH_3 is pumped to the process by reciprocating pumps (steam driven) that raise the NH_3 pressure for the reactor use.

The urea formation occurs in a reactor where spontaneous formation of ammonium carbamate under exothermic conditions starts. Extending the reactor time allows the further dehydration of the carbamate solution to form urea. Once the urea formation has occurred, a series of separations is used to remove unconverted NH_3, CO_2, and carbamate as well as water. The product stream leaving this reaction section of the plant is primarily urea and water. In Plant 5, the reactor section of the plant is a high-pressure synthesis loop that uses condenser and stripper units to control and optimize the urea formation reaction. In connection with this synthesis loop, Plant 5 uses a rectifying column, a condenser, and a scrubber to complete the urea product stream separation from the unreacted NH_3 and CO_2. These reaction materials are recovered and recycled back to the reaction process.

The produced urea and water streams must be dried further in order to complete processing. Plant 5 uses two evaporators that rely on heat and vacuum conditions to help remove the water. In both plants the water removed is collected and treated for reuse. Plant 5 completes the same treatment function with a separate hydrolyzer and desorber.

The last major process function is the conversion of the concentrated urea stream into finished urea granules.

Plant 5 uses four rotating drum granulators in the finishing step. The drums contain undersized product granules that constantly are churned and exposed to the direct spray of concentrated urea from the evaporators. Larger granules are formed through the contacting and cooling from air passed through the granulators. These larger granules are removed from the units by conveyors and sized with screens. The properly sized granules are sent to a storage warehouse, and the off-sized granules are recycled through the granulator process.

Enclosed belt conveyors deliver the product to the warehouses, and enclosed belt conveyors transfer the product to the ship loading dock. A specially designed telescopic loading boom is used to load cargo holds with urea.

Utility Plants

The utility plants are set up to provide power to each half of the plant. Power Plant 6 provides power for Ammonia Plant 4, Urea Plant 5, and itself. Electrical power comes from gas turbine generators and by purchase from a local utility. Steam is produced through boilers, but is also produced through waste heat recovery boilers. The steam production is integrated between direct production and waste heat recovery to maximize energy efficiency for the plant.

2. EMISSIONS SUMMARY AND PERMIT APPLICABILITY

2.1. Emissions Summary and Permit Applicability

During the construction phase, Agrium will operate several non-road engines (NRE). The Department did not include NRE emissions in the emissions calculations because they do not count towards determining permit classification of the stationary source. Constructions emissions are excluded from the determination of PSD applicability based on two provisions of 40 CFR 52.21. 40 CFR 52.21(b)(18) describes secondary emissions as "emissions which would occur as a result of construction or operation of a major stationary source or major modification, but do not come from the major stationary source or the major modification itself." 40 CFR 52.21(b)(4) states "Secondary emissions do not count in determining the potential to emit of a stationary source".

Table 1 shows a summary of the project's potential to emit (PTE) for the permanent phase for NOx, CO, PM, PM-10, PM-2.5, VOC, SO_2, and GHGs as carbon dioxide equivalent (CO_2e).

Emissions from the five turbines are based off a maximum of 8,760 hours of operation per year. Emissions for NOx and CO are based on the BACT determination detailed in Appendix B, using selective catalytic reduction, achieving 7 ppmv NOx at 15% O_2 for combined Solar Turbine/ Waste Heat Boiler exhaust (approximately 0.047 lb/MMBtu NOx emission rate from Solar Turbine). PM, PM-10, PM-2.5, VOC, SO_2, and GHGs are based off AP-42 emission factors.

The cooling tower, Stack ID 40, only emits PM-2.5 and PM-10. Calculations were based off a cooling water circulation rate of 15,000 gal/min, a maximum total dissolved solids in water equal to 5,000 mg/l and a maximum liquid drift rate of 0.002 percent of the circulating water. These calculations were also based off 8,760 hours of operation per year.

Emissions from the diesel fired well pump and gasoline fired water pump, Stack IDs 65 and 66, are based off 168 hours of operation per year.

Total assessable emissions for the source are 1,232 tons per year (tpy).

Agrium's application shows that the source's PTE hazardous air pollutants (HAPs) are 73.8 tpy. Under Section 112 of the Clean Air Act, HAP program, any stationary source that has the potential to emit, considering controls, 10 tpy or more of any listed HAP or 25 tpy or more of any combination of listed HAPs is classified as a "major source" of HAPs. Major sources of HAPS must comply with the National Emission Standards for Hazardous Air Pollutants (NESHAPs) requirements, established as technology-based standards based on maximum achievable control technology (MACT). However, under 40 CFR 63.2 Subpart A (General Provisions), a source is only "new" if it constructs or reconstructs after the proposal date of the applicable MACT standard. The KNO facility was operational when the Subpart DDDDD NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters rule was proposed on September 13, 2004, and is therefore an existing source. A source does not lose its regulatory status under the 40 CFR Part 63 rules if it shuts down, permanently or otherwise, and then starts back up[1]. Therefore the KNO facility is not subject to a "case-by-case" MACT determination.

[1] 7/27/1998 EPA Region 8 Guidance Re: Applicability of 40 CFR Part 63 Subpart R to Phillips La Junta Terminal Processes.

Table 1: Emissions from Stationary EUs at the KNO Facility, Tons per Year

Description	NOx	CO	PM	PM-10	PM-2.5	VOC	SO_2	CO_2e
PTE for AQ0083CPT06	214.1	730.5	116.6	174.8	171.0	114.2	8.9	2,160,432
PSD Applicability Threshold	40	100	25	15	10	40	40	100,000
PSD Applicability Triggered?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**Yes**
Assessable Emissions	**214**	**731**	**N/A**	**175**	**N/A**	**114**	**N/A**	**N/A**
	1,234							

CO emissions exceed 100 tpy and subject the source to PSD review for each regulated NSR pollutant that has the potential to emit in quantities that exceed the significant thresholds listed in 40 CFR 52.21(b)(23)(i). As shown in Table 1, the stationary source has the potential to emit NOx, PM, PM-10, PM-2.5 and VOC above the thresholds in 40 CFR 5.21(b)(23)(i).

2.2. Department Findings

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

1. The KNO facility is classified as a major stationary source under 40 CFR 52.21(b)(1)(i)(b) since it has the potential to emit more than 100 tons per year of a regulated air pollutant;
2. The KNO facility has potential NOx, CO, PM, PM-10, PM-2.5, and VOC emissions that are PSD significant, per 40 CFR 52.21(b)(23). Therefore, the project requires a PSD permit under 18 AAC 50.306(a) for these pollutants.
3. Agrium did not include BACT analyses for the organic sulfur removal vent (EU 15), the amine fat flasher vent (EU 16), the PC stripper tank vent (EU 17), the atmospheric absorber final scrubber (EU 37), or the inerts vent scrubber (EU 38). These emission units have an aggregate PTE VOC of 1.25 tons per year. VOC controls for these units are economically infeasible for the small potential VOC emissions that could be controlled.
4. KNO is an existing fertilizer manufacturing facility that has been inoperative for the last several years. At Agrium's request, the Department rescinded all previous air quality control permits and application shields on October 26, 2009. The Department further noted that, "resumption of emitting activities at the Kenai Nitrogen Operations will constitute a new stationary source under Air Quality Control Regulations." Agrium is proposing to restart a portion of the KNO facility. Therefore, while the KNO facility exists, the Department is treating it as a new stationary source for air quality permitting purposes.

3. PSD PERMIT REQUIREMENTS

Under 18 AAC 50.306, the Permittee must satisfy the requirements under 40 CFR 52.21. The elements the Department must include in PSD permits are listed in 40 CFR 52.21(j) through (p). This section and associated sub-sections outline these provisions.

40 CFR 52.21(j)(1) requires that the major source meet the applicable local standards, state requirements established in the Alaska State Implementation Plan (SIP), and federal standards of performance in 40 CFR 60 and 61. The source must meet each applicable state and federal emissions standard described in Sections 3.1 and 3.2 of this TAR, the standards and associated monitoring requirements will be carried forward into the Title V operating permit for the source.

40 CFR 52.21(j)(2) requires a major stationary source to apply Best Available Control Technology (BACT) for each regulated New Source Review pollutant that has the potential to emit greater than the significant amounts listed in 40 CFR 52.21(b)(23)(i). Appendix B and Appendix C, present details of the BACT analysis for NOx, CO, VOC, PM, PM-10, PM-2.5, and GHGs.

40 CFR 52.21(k) through (o) requires that the source contain the requirements under each section as applicable:

> 40 CFR 52.21(k) - *Source Impact Analysis*: This includes a review of the allowable emissions increase concerning the Alaska Ambient Air Quality Standards and increments;
>
> 40 CFR 52.21(l) – *Air Quality Models*: Use of air quality models that are consistent with Appendix W of 40 CFR 51;
>
> 40 CFR 52.21(m) – *Air Quality Analysis*: Measured ambient air quality data, unless exempted under 40 CFR 52.21(i)(5);
>
> 40 CFR 52.21(n) - *Source Information*: Include all information about the source including a description of the nature, design capacity, location, schedule for modification and layout;
>
> 40 CFR 52.21(o) – *Additional Impact Analyses*: The source must review air quality impacts on the project area, such as visibility; and
>
> 40 CFR 52.21(p) – *Sources Impacting Federal Class I Areas*: Review air quality impacts on the Federal Class I area.

The requirements under 40 CFR 52.21(k) through (p) are addressed in the modeling memorandum in Appendix D of this TAR.

3.1. State Emission Standards

40 CFR 52.21(j)(1) requires the stationary source to meet each applicable limitation under the Alaska SIP.

3.1.1. 18 AAC 50.055(a)(1): Industrial Process and Fuel-Burning VE Standards

Section 3 of the permit contains conditions that require initial compliance using 40 CFR 60, Appendix A, Reference Method 9 observation to ensure the applicable diesel-fired equipment at the facility comply with the standard.

3.1.2. 18 AAC 50.055(b)(1): Industrial Process and Fuel-Burning PM Standards

Industrial process equipment and fuel-burning equipment at the stationary source must comply with 18 AAC 50.055(b)(1), the state PM standards of 0.05 grains per dry standard cubic foot of exhaust.

3.1.3. 18 AAC 50.055(c): Sulfur Compound Emissions Standards

Industrial process equipment and fuel-burning equipment at the stationary source must comply with 18 AAC 50.055(c), the state sulfur compounds emissions standard. Sulfur compound emissions, expressed as SO_2, from an industrial process or from fuel-burning equipment may not exceed 500 parts per million by volume (ppmv) averaged over a period of three hours. This permit does not include SO_2 initial or periodic monitoring because these units will be subject to on-going MR&R when incorporated into the Title V permit.

3.2. Federal Emission Standards

3.2.1. 40 CFR 60, Subpart D – Standards of Performance for Fossil Fuel-Fired Steam Generators

This subpart applies to fossil fuel-fired steam generators for which construction or modification commenced after August 17, 1971 and with a firing capacity of greater than 250 MMBtu/hr. A fossil fuel-fired steam generating unit means a furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer. Under the terms of a 1998 Consent Decree, the United States Environmental Protection Agency determined that even though the primary function of the reformer is to reform process gas, the auxiliary section is a discrete unit whose primary function is to produce steam. The primary reformer must comply with the PM, visible emissions (VE), and NOx emission limits found in:

40 CFR 60.42(a)(1)	40 CFR 60.42(a)(2)	40 CFR 60.44(a)(1)

3.2.2. 40 CFR 60, Subpart Db – Standards of Performance for Industrial, Commercial, and Institutional Steam Generating Units

This subpart applies to natural gas-fired steam generating units that commenced construction after June 19, 1984, and have a maximum design heat capacity of 100 MMBtu/hr or greater. The source will contain three new 243 MMBtu/hr package boilers that must comply with the NOx and SO_2 emissions limits specified in:

40 CFR 60.42(b)(k)(2)	40 CFR 60.44(b)(a)	40 CFR 60.45(b)(j)
40 CFR 60.46(b)(c)	40 CFR 60.48(b)(1)	40 CFR 60.49(b)(d)(1)
40 CFR 60.49(b)(g)		

3.2.3. NESHAPs Standards for Industrial, Commercial, and Institutional Boilers and Process Heaters

The KNO facility is a major source of HAPs that contains a primary reformer, startup heater, three package boilers, and five waste heat boilers that must meet the applicable requirements contained in 40 CFR 63 Subpart DDDDD for Industrial, Commercial, and Institutional Boilers and Process Heaters. These units must comply with the applicable emission limits, work practice requirements, and recordkeeping and reporting requirements listed in:

40 CFR 63.7500(e)	40 CFR 63.7540(a)(10)	40 CFR 63.7545(a)
40 CFR 63.7550(a)	40 CFR 63.7555	40 CFR 63.7521(g)

3.2.4. NESHAPs Standards for Equipment Leaks

The KNO facility is subject to the applicable NESHAPs requirements for equipment leaks that includes the equipped components on the UF-85 tank and lines transferring UF-85 from the tank to process lines (transfer lines to unload the product to the tank are exempt because they will operate less than 300 hours per year as indicated in the 2007 Miscellaneous Organic Chemical Manufacturing Study prepared by Trinity Consultants for the KNO Facility).

3.2.5. NESHAPs Standards for Reciprocating Internal Combustion Engines

The KNO facility is subject to the applicable NESHAPs requirements for reciprocating internal combustion engines contained in 40 CFR Subpart ZZZZ.

3.3. Standard Permit Conditions

As required under 18 AAC 50.345 and 18 AAC 50.346, the Department must include the standard permit conditions (b) through (o). Section 10 of the permit lists these standard permit conditions.

4. PERMIT ADMINISTRATION

The stationary source has the potential to emit more than 100 tpy of one or more pollutants. Therefore, a timely Title V application for the stationary source is due no later than 12 months after the stationary source commences operation.

APPENDIX A: EMISSIONS CALCULATIONS

Table A-1 presents details of the EUs, their characteristics, and emissions. The Department obtained the emissions from Attachment B.1 of the January 29, 2014 permit application.

Table A-1: Detailed Permanent EU Inventory and Tons Emitted per Year

ID	Unit ID/ Description	Hours	Rating		NO_X CO EF Units	NO_X		CO		VOC PM PM-10 PM-2.5 EF Units	VOC		PM		PM-10		PM-2.5		SO_2
						EF	PTE (tpy)	EF	PTE (tpy)		EF	PTE (tpy)	EF	PTE (tpy)	EF	PTE (tpy)	EF	PTE (tpy)	PTE[8] (tpy)
11	Ammonia Tank System Flare	8,760	1.25	MMBtu/hr	lb/MMBtu	0.068	0.37	0.37	2.03	lb/MMBtu	0.14	0.77	0.0019	0.01	0.0074	0.041	0.0074	0.041	0.003
12	Primary Reformer B-201	8,760	1350	MMBtu/hr	lb/ MMBtu	0.02	118.26	0.0426	251.9	lb/MMscf	5.5	31.88	1.9	11.01	7.6	44.06	7.6	44.06	3.48
13	Startup Heater B-200	200	101	MMBtu/hr	lb/MMscf	100	0.99	84	0.83	lb/MMscf	5.5	0.054	1.9	0.019	7.6	0.075	7.6	0.075	0.006
14	CO_2 Vent D-207	8,760	90	tons per hour	lb/hr	-	-	2.9	12.70	lb/hr	11.4	49.9	-	-	-	-	-	-	-
15	Organic S Removal Vent H-205	1,248	1	24-hr regen/ wk	-	-	-	-	-	ton/yr	0.01	0.01	-	-	-	-	-	-	-
16	Amine Fat Flasher Vent H-269	8,760	-	-	lb/hr	-	-	1.05	4.6	lb/hr	0.22	0.96	-	-	-	-	-	-	-
17	PC Stripper Tank Vent F-263	8,760	-	-	-	-	-	-	-	lb/day	1.3	0.24	-	-	-	-	-	-	-
19	H2 Vent Stack (dry gas) C-200	200	4	startups/yr	lb/ startup	-	-	15,222	126.9	-	-	-	-	-	-	-	-	-	-
22	Plants 4 and 5 Small Flare B-502	8,760	1.25	MMBtu/hr	lb/MMBtu	0.068	0.38	0.37	2.03	lb/MMBtu	0.14	0.77	0.0019	0.01	0.0074	0.041	0.0074	0.041	0.003
23	Plants 4 and 5 Emergency Flare B-501	8,760	0.4	MMBtu/hr	lb/MMBtu	0.068	0.20	0.37	0.65	lb/MMBtu	0.14	0.25	0.0019	0.003	0.0074	0.013	0.0074	0.013	0.001
35	Granulator A/B Scrubber Exhaust Vent C-560A	8,760	50	tons per hour	-	-	-	-	-	lb/ton	-	1.75	0.2	43.8	0.2	43.8	0.2	43.8	-
36	Granulator C/D Scrubber Exhaust Vent C-560B	8,760	50	tons per hour	-	-	-	-	-	lb/ton	-	1.75	0.2	43.8	0.2	43.8	0.2	43.8	-
37	Atmospheric Absorber Final Scrubber D-515	8,760	-		-	-	-	-	-	lb/hr	0.022	0.10	-	-	-	-	-	-	-

ID	Unit ID/ Description	Hours	Rating		NO_X CO EF Units	NO_X		CO		VOC PM PM-10 PM-2.5 EF Units	VOC		PM		PM-10		PM-2.5		SO_2
						EF	PTE (tpy)	EF	PTE (tpy)		EF	PTE (tpy)	EF	PTE (tpy)	EF	PTE (tpy)	EF	PTE (tpy)	PTE[8] (tpy)
38	Inerts Vent Scrubber D-511	8,760	-	-	-	-	-	-	-	lb/hr	0.028	0.12	-	-	-	-	-	-	-
39	After Condenser Exchanger E-535	8,760	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	Cooling Tower E-711	8,760	15,000	gal per min	-	-	-	-	-	lb/ 1000gal	-	-	0.00083	3.29	29.97% of PM	0.99	0.18% of PM	0.006	-
41-41C	Tanks & Scrubber D-514, D-513, F-209, F-615	8,760	-	-	-	-	-	-	-	lb/hr	tanks	0.002	-	-	-	-	-	-	-
44	Package Boiler 6B-708C	8,760	243	MMBtu/hr	lb/MMBtu	0.01	10.64	0.037	39.38	lb/MMscf	5.5	5.74	1.9	1.98	7.6	7.93	7.6	7.93	0.63
47	Urea Loading Wharf	8,760	1,000	tons per hour	-	-	-	-	-	lb/ton	-	-	0.02	4.38	0.017	3.72	0.006	1.31	-
47B	Urea Warehouse and Transfer Fugitives	8,760	1,000	tons per hour	-	-	-	-	-	lb/ton	-	-	0.02	0.44	0.017	0.37	0.006	0.13	-
47C	Urea Warehouse and Transfer Stack Emissions	8,760	1,000	tons per hour	-	-	-	-	-	lb/ton	-	-	0.02	0.083	0.017	0.071	0.006	0.025	-
47D	Urea Transfer to Loading Warf	8,760	1,000	tons per hour	-	-	-	-	-	lb/ton	-	-	0.02	0.088	0.017	0.074	0.006	0.026	-
48	Package Boiler 6B-708B	8,760	243	MMBtu/hr	lb/MMBtu	0.01	10.64	0.037	39.38	lb MMscf	5.5	5.74	1.9	1.98	7.6	7.93	7.6	7.93	0.63
49	Package Boiler 6B-708A	8,760	243	MMBtu/hr	lb/MMBtu	0.01	10.64	0.037	39.38	lb/MMscf	5.5	5.74	1.9	1.98	7.6	7.93	7.6	7.93	0.63
50	Waste Heat Boiler B-705A	8,760	50	MMBtu/hr	lb/MMBtu	0.009	1.97	0.109	23.87	lb/MMscf	5.5	1.18	1.9	0.41	7.6	1.63	7.6	1.63	0.13
51	Waste Heat Boiler B-705B	8,760	50	MMBtu/hr	lb/MMBtu	0.009	1.97	0.109	23.87	lb/MMscf	5.5	1.18	1.9	0.41	7.6	1.63	7.6	1.63	0.13
52	Waste Heat Boiler B-705C	8,760	50	MMBtu/hr	lb/MMBtu	0.009	1.97	0.109	23.87	lb MMscf	5.5	1.18	1.9	0.41	7.6	1.63	7.6	1.63	0.13
53	Waste Heat Boiler B-705D	8,760	50	MMBtu/hr	lb/MMBtu	0.009	1.97	0.109	23.87	lb/MMscf	5.5	1.18	1.9	0.41	7.6	1.63	7.6	1.63	0.13
54	Waste Heat Boiler B-705E	8,760	50	MMBtu/hr	lb/MMBtu	0.009	1.97	0.109	23.87	lb/MMscf	5.5	1.18	1.9	0.41	7.6	1.63	7.6	1.63	0.13
55	Solar Turbine/Gen Set GGT-744A	8,760	37.6	MMBtu/hr	lb/MMBtu	0.047	9.57	0.109	17.95	lb/MMBtu	0.0021	0.35	0.0019	0.31	0.0066	1.09	0.0066	1.09	0.56
56	Solar Turbine/Gen Set GGT-744B	8,760	37.6	MMBtu/hr	lb/MMBtu	0.047	9.57	0.109	17.95	lb/MMBtu	0.0021	0.35	0.0019	0.31	0.0066	1.09	0.0066	1.09	0.56

ID	Unit ID/ Description	Hours	Rating		NO_X CO EF Units	NO_X		CO		VOC PM PM-10 PM-2.5 EF Units	VOC		PM		PM-10		PM-2.5		SO_2
						EF	PTE (tpy)	EF	PTE (tpy)		EF	PTE (tpy)	EF	PTE (tpy)	EF	PTE (tpy)	EF	PTE (tpy)	PTE[8] (tpy)
57	Solar Turbine/Gen Set GGT-744C	8,760	37.6	MMBtu/hr	lb/MMBtu	0.047	9.57	0.109	17.95	lb/MMBtu	0.0021	0.35	0.0019	0.31	0.0066	1.09	0.0066	1.09	0.56
58	Solar Turbine/Gen Set GGT-744D	8,760	37.6	MMBtu/hr	lb/MMBtu	0.047	9.57	0.109	17.95	lb/MMBtu	0.0021	0.35	0.0019	0.31	0.0066	1.09	0.0066	1.09	0.56
59	Solar Turbine/Gen Set GGT-744E	8,760	37.6	MMBtu/hr	lb MMBtu	0.047	9.57	0.109	17.95	lb/MMBtu	0.0021	0.35	0.0019	0.31	0.0066	1.09	0.0066	1.09	0.56
60	Deaerator Vent	8,760	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61	Degasifier Vent	8,760	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65	Diesel Fired Well Pump GM-616D	168	2.7	MMBtu/hr	lb/MMBtu	4.41	1.0	0.95	0.22	lb/MMBtu	0.36	0.08	0.31	0.07	0.31	0.07	0.31	0.07	0.07
66	Gasoline Fired Firewater Pump	168	2.1	MMBtu/hr	lb/MMBtu	1.63	0.29	0.99	0.17	lb/MMBtu	3.03	0.53	0.1	0.018	0.1	0.018	0.1	0.02	0.01
IEU	Building Heaters/ Water Heaters	8,760	7.3	MMBtu/hr	lb/MMscf	94	2.95	40	1.25	lb/MMscf	5.5	0.17	1.9	0.06	7.6	0.24	7.6	0.24	0.02
Total Existing Potential to Emit Emissions							**214.1**		**730.5**			**114.2**		**116.6**		**174.8**		**171.0**	**8.9**

Table Notes: Table Notes:
Fuel Gas Heat Content: 1,091 Btu/scf
CO Emission Factor Units for EU IDs 14 and 15 are given in lb/MMBtu
PM Emission Factor for Urea Loading Wharf is limited by the capacity of urea granulation plant and includes a 50 percent control efficiency due to partial enclosure and use of UF-85, a hardening agent
NOx Emissions for the Solar Turbines include 204 hr/yr (each) during which the turbines will operate without the Waste Heat Boilers (bypassing the SCR control system)

APPENDIX B: BACT ANALYSIS NOX, CO, PM, PM-10, PM-2.5, AND VOC

1.0 Introduction

The Kenai Nitrogen Operations (KNO) facility triggered PSD requirements for oxides of nitrogen (NOx), carbon monoxide (CO), particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers (PM-2.5), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM-10), volatile organic compounds (VOC), and greenhouse gases (GHGs). This appendix reviews Agrium's Best Available Control Technology (BACT) analysis for NOx, CO, PM, PM-10, PM-2.5, and VOC for its technical accuracy and adherence to accepted engineering cost estimation practices. Appendix C presents the BACT analysis for GHG.

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 CFR 52.21(b)(12) defines BACT as a site-specific determination on a case-by-case basis. The Department's goal is to identify BACT for the permanent emission units (EUs) at the KNO facility that emit NOx, CO, PM, PM-10, PM-2.5, and VOC, establish emission limits which represent BACT, and assess the level of monitoring, recordkeeping, and reporting (MR&Rs) necessary to ensure Agrium 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 B-1 presents the EUs subject to BACT review.

Table B-1: EUs Subject to BACT Review

EU ID	Description of EU
11	Ammonia Tank System Flare
12	Primary Reformer
13	Startup Heater
14	CO_2 Vent
15	Organic S Removal Vent
16	Amine Fat Flasher Vent
17	PC Stripper Tank Vent
19	H_2 Vent Stack
22	Plants 4 and 5 Small Flare
23	Plants 4 and 5 Emergency Flare
35	Granulator A/B Scrubber Exhaust Vent
36	Granulator C/D Scrubber Exhaust Vent
37	Atmospheric Absorber Final Scrubber
38	Inerts Vent Scrubber
39	After Condenser Exchanger
40	Cooling Tower
41-41C	Tanks and Scrubber
47-47D	Urea Loading Wharf
44, 48, and 49	Package Boilers

EU ID	Description of EU
50 – 54	Waste Heat Boilers
55 – 59	Solar Turbines / Gen Sets
60	Deaerator Vent
61	Degasifier Vent
65	Diesel Fired Well Pump
66	Gasoline Fired Fire Pump Engine

Agrium did not include BACT analyses for the organic sulfur removal vent (EU 15), the amine fat flasher vent (EU 16), the PC stripper tank vent (EU 17), the atmospheric absorber final scrubber (EU 37), or the inerts vent scrubber (EU 38). These emission units have an aggregate PTE VOC of 1.25 tons per year. VOC controls for these units are economically infeasible for the small potential VOC emissions that could be controlled.

Five-Step BACT Determinations

The following sections explain the steps used to determine BACT for NOx, CO, PM, PM-10, PM-2.5, and VOC 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, PM, PM-10, PM-2.5, and VOC emissions from equipment similar to those listed in Table B-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. Sections 3, 4, 5, 6, and 7 present the Department's BACT Determinations for NOx, CO, PM, PM-10, PM-2.5, and VOC.

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 Agrium's BACT analysis for the KNO Facility and made BACT determinations for NOx, CO, PM, PM-10, PM-2.5, and VOC for various EUs based on the information submitted by Agrium in their application, information from vendors, suppliers, sub-contractors, RBLC, and an exhaustive internet search.

3.0 BACT Determination for NOx

The KNO facility has five existing 37.6 MMBtu/hr Solar Centaur GSC-4000 turbines that burn natural gas, one 1,350 MMBtu/hr primary reformer, heaters, boilers, flares, and several other EUs subject to BACT. The Department reviewed the control technologies Agrium identified in their application and determined NOx BACT for the EUs listed in Table B-1.

The Department based its assessment on BACT determinations found in the RBLC and internet research. Table B-2 summarizes NOx BACT determinations in the RBLC for the proposed EUs.

Table B-2: NOx BACT Determinations in RBLC for January 2004-August 8, 2014

Description of NOx BACT	Fuel Gas Turbines	Primary Reformer	Startup Heater	Boilers	Flares	Well and Fire Pump
Good Combustion Practices	1	3	3	3	5	4
Good Operating Practices				1	2	
Clean Fuels			2	1		
Combustion Control						2
Low NOx Burners	4	3		5		
Oxidation Catalyst	2	4				
Limit Hours of Operation				2		
Fuel Use Limits				1		
Flue Gas Recirculation				3		
Emission Unit Design			2			
Flare Minimization Practices					3	
Total	**7**	**10**	**7**	**16**	**10**	**6**

3.1 NOx BACT for the Turbines (EUs 55 through 59)

Step 1- Identification of NOx Control Technology for the Turbines
From research, the Department identified the following technologies as available for NOx control of turbines rated at 25 MW or less:

(a) Selective Catalytic Reduction (SCR)
SCR is a post-combustion gas treatment technique for reducing nitric oxide (NO) and nitrogen dioxide (NO_2) in the turbine exhaust stream to molecular nitrogen (N_2), water, and oxygen (O_2). In the SCR process, aqueous or anhydrous ammonia (NH_3) is injected into the flue gas upstream of a catalyst bed. The catalyst lowers the activation energy of the NOx decomposition reaction. NOx and NH_3 combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental N_2 and water. Depending on the overall NH_3-to-NOx ratio, removal efficiencies are generally 80 to 90 percent. SCRs can reduce concentration of NOx in the exhaust of gas-fired turbines to as low as 9 parts per million by volume (ppmv). Challenges associated with using SCR on small turbines include a narrow window of acceptable inlet and exhaust temperatures (500°F to 800°F), emission of NH_3 into the atmosphere (NH_3 slip) caused by non-stoichiometric reduction reaction, and disposal of depleted catalysts. The Department considers SCR a feasible control technology for turbines.

(b) Selective Non-Catalytic Reduction (SNCR)
SNCR involves the non-catalytic decomposition of NOx in the flue gas to N_2 and water using reducing agents such as urea or NH_3. The process utilizes a gas phase homogeneous reaction between NOx and the reducing agent within a specific temperature window. The reducing agent must be injected into the flue gas at a location in the unit that provides the optimum reaction temperature and residence time. The NH_3 process (trade name-Thermal DeNOx) requires a reaction temperature window of 1,600°F to 2,200°F. In the urea process (trade name–NO_xOUT), the optimum temperature ranges between 1,600 °F and 2,100 °F. Because the temperature of 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 turbines.

(c) Non-Selective Catalytic Reduction (NSCR)
NSCR simultaneously reduces NOx and oxidizes CO and hydrocarbons in the exhaust gas to N_2, carbon dioxide (CO_2), and water. The catalyst, usually a noble metal, causes the reducing gases in the exhaust stream (hydrogen, methane, and CO) to reduce both NO and NO_2 to N_2 at a temperature between 800°F and 1,200°F. 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 turbines.

(d) Water & Steam Injection

Water/steam injection involves the introduction of water or steam into the combustion zone. The injected fluid provides a heat sink which absorbs some of the heat of reaction, causing a lower flame temperature. The lower flame temperature results in lower thermal NOx formation. Both steam and water injections are capable of obtaining the same level of control. The process requires approximately 0.8 to 1.0 pound of water or steam per pound of fuel burned. The main technical consideration is the required purity of the water or steam, which is required to protect the equipment from dissolved solids. Obtaining water or steam of sufficient purity requires the installation of rigorous water treatment and deionization systems.

Water/steam injection is a proven technology for NOx emissions reduction from turbines. However, the arctic environment presents significant challenges to water/steam injection due to cost of water treatment, freezing potential due to extreme cold ambient temperatures, and increased maintenance problems due to accelerated wear in the hot sections of the turbines. Moreover, the vendor of the turbines does not recommend using water/steam injection to control NO_x emissions from the turbines because of the extra maintenance problems. The Department considers water/steam injection a technically feasible control technology for the turbines.

(e) Low NOx Burners (LNBs)

Using LNBs can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature. Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 60% but under certain conditions, higher reductions are possible. The Department considers the use of LNBs as a technically feasible control technology for the turbines.

(f) SCONOX™

SCONOX™ is a new technology that treats exhaust gas by reducing NOx to N_2. The SCONOX™ catalytic absorption system uses a potassium carbonate coated catalyst to reduce NOx to N_2. The catalyst 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 turbines.

(g) XONON™

XONON™ is a catalytic technology that uses flameless fuel combustion. 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. The Department considers XONON™ a technically infeasible control technology because it is not commercially available.

(h) Good Combustion Practices (GCPs)

GCPs typically include the following elements:

1. Sufficient residence time to complete combustion;
2. Providing and maintaining proper air/fuel ratio;
3. High temperatures and low oxygen levels in the primary combustion zone;
4. High enough overall excess oxygen levels to complete combustion and maximize thermal efficiency;
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. GCP is considered a technically feasible control option for the turbines.

Step 2 - Elimination of Technically Infeasible NOx Control Options for Turbines

As explained in Section 3.1, SNCR, NSCR, SCONOX™, and XONON™ are not feasible technologies to control NO_x emissions from turbines smaller than 25 MW.

Step 3 - Ranking of Remaining NOx Control Technologies for Turbines

The following control technologies have been identified and ranked for control of NOx from the turbines:

(a)	SCR and Water Injection	(80% - 95% Control)
(b)	SCR	(70% - 92% Control)
(c)	LNB	(80% Control)
(d)	Water Injection	(50% - 70% Control)
(e)	GCP	(Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units (combustion turbines rated at less than 25 MW). All data in this table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Solar Combustion Turbines (EUs 55 through 59) – NOx						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
AK-0066	BP-Endicott	6/15/09	Gas Turbine	7.5 MW	25 ppm_{vd} at 15% O_2	LNB
AK-0076	Exxon Pt Thomson	8/20/12	Gas Turbine	7.52 MW	15 ppmvd at 15% O2	LNB
CA-1216	Grossmont Hospital	11/6/12	Gas Turbine with Duct Burner	4.6 MW	9 ppm_{vd} at 15% O_2 (1-hr avg.)	LNB
CT-0155	Wesleyan University	8/27/08	Gas Turbine	22.3 MMBtu/hr	0.18 g/bhp-hr	SCR
FL-0313	Cutrale Citrus	6/12/08	Gas Turbine	62.7 MMBtu/hr	25 ppm_{vd} at 15% O_2	LNB
PA-0289	Geisinger Medical Center	6/18/10	Gas Turbine	55.62 MMBtu/hr	15 ppm_{vd} at 15% O_2	LNB
WY-0067	Echo Springs Gas Plant	4/1/09	Gas Turbine	12,555 hp	15 ppm_{vd} at 15% O_2	LNB
WY-0067	Echo Springs Gas Plant	4/1/09	Gas Turbine	16,162 hp	15 ppm_{vd} at 15% O_2	GCP
WY-0067	Echo Springs Gas Plant	4/1/09	Gas Turbine	3,856 hp	25 ppm_{vd} at 15% O_2	LNB
IN-0180	Midwest Fertilizer Corp.	6/4/14	Gas Turbine	283 MMBtu/hr	22.65 ppm_{vd} at 15% O_2	LNB
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Five Gas Combustion Turbines**	**37.6 MMBtu/hr (each)**	**7 ppm_{vd} at 15% O2**	**SCR**

RBLC Review

A review of similar units in the RBLC indicates selective catalytic reduction, low NOx burners, and good combustion practices are the principle NOx control technologies installed on gas turbines.

Applicant Proposal

The applicant provided an economic analysis of the installation of water injection on the turbines to demonstrate that the use of water injection in conjunction with SCR is not economically feasible on these units. A summary of the analysis is shown below:

Control Alternative	Captured Emissions (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Operating Costs ($/year)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Water Injection	48	6.7	$361,820	$21,350	$72,873	$10,876
Capital Recovery Factor = 0.1424 (7% for a 10 year life cycle)						

The economic analysis indicates the level of NOx reduction does not justify the use of water injection to be used in conjunction with selective catalytic reduction. Based on the excessive cost per ton of NOx removed per year, installing water injection on the turbines is not considered a feasible option for reducing NOx emissions.

The applicant proposes the following as BACT:

(a) NOx emissions from the operation of the four combustion turbines (EUs 55 through 59) shall be controlled by SCR at all times the turbines are in operation.

(b) NOx emissions from the turbines at the waste heat boiler outlet shall not exceed 7 ppm_{vd} at 15% oxygen, equivalent to a NOx emission limit of 0.047 lb/MMBtu.

(c) Compliance with the proposed emission limit will be demonstrated by conducting an initial stack test to obtain an emission rate.

Step 5 – Selection of NOx BACT for Turbines
The Department agrees with the applicant that an emission rate achievable with SCR is BACT for the turbines. NOx emissions from each of the natural gas-fired combustion turbines (EUs 55 through 59) shall be controlled by use of SCR and shall not exceed 7 ppm_{vd} at 15% oxygen. For the Solar Turbines, this will be equivalent to a NOx emission limit of 0.047 lb/MMBtu.

3.2 NOx BACT for the Primary Reformer (EU 12)

Step 1 – Identification of NOx Control Technology for the Primary Reformer
From research, the Department identified the following technologies as available for NOx control of reformer furnaces:

(a) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT for the turbines and will not be repeated here. The Department considers SCR a feasible control technology for the primary reformer.

(b) Selective Non-Catalytic Reduction
The theory of SNCR was discussed in detail in the NOx BACT for the turbines and will not be repeated here. Because the effluent gas temperatures from the primary reformer exhaust undergo extensive heat recovery, they are not high enough to achieve the required reaction temperature. The Department research did not identify SNCR used to control NOx emissions from reformer furnaces installed at any facility. Hence the Department did not consider SNCR as a feasible control technology for the primary reformer.

(c) Low NOx Burners
The theory of LNBs was discussed in detail in the NOx BACT for the turbines and will not be repeated here. The use of LNBs is a technically feasible control option for the primary reformer.

(d) Ultra-Low NOx Burners
ULNBs use a similar technique as LNBs, however they also employ flue gas recirculation to lower the flame temperature and achieve lower NOx formation than from use of LNBs. The use of ULNBs is considered a technically feasible control technology for the primary reformer.

(e) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of NOx emissions. GCPs is considered a technically feasible control option for the primary reformer.

Step 2 – Eliminate Technically Infeasible NOx Control Options for the Primary Reformer
As explained in Section 3.2, SNCR is not technically feasible to control NOx emissions from the primary reformer.

Step 3 – Ranking of the Remaining NOx Control Technologies for the Primary Reformer
The following control technologies have been identified and ranked for the control of NOx from the primary reformer (EU 12).

(a) SCR and LNB (85% - 95% Control)
(b) SCR (90% Control)
(c) ULNB (50% - 90% Control)
(d) LNB (40% - 60% Control)
(e) GCP (Less than 40% Control)

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Primary Reformer (EU 12) – NOx						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
TX-0657	Beaumont Gas to Gasoline Plant	5/16/14	Primary Reformer	1,552 MMBtu/hr	0.01 lb/MMBtu (annual avg.)	SCR
LA-0272	Dyno Nobel Louisiana Ammonia	3/27/13	Primary Reformer	956.2 MMBtu/hr	0.014 lb/MMBtu (annual avg.)	SCR & LNB
IA-0105	Iowa Fertilizer Company	10/26/12	Primary Reformer	1,152.6 MMBtu/hr	9 ppm_{vd} (30-day avg.)	SCR
IN-0172	Ohio Valley Resources	9/25/13	Primary Reformer	1,006.4 MMBtu/hr	9 ppm_{vd} (30-day avg.)	SCR & GCP
OK-0134	Pryor Plant Chemical Company	2/23/09	Primary Reformer	700 ton ammonia per day	0.2 lb/MMBtu, 11.93 lb/hr (3-hr, 168 rolling cumulative.)	LNB GCP
LA-0211	Garyville Refinery	12/27/06	Hydrogen Reformer	1,412.5 MMBtu/hr	0.0125 lb/MMBtu (annual avg.)	ULNB & SCR
NM-0050	Artesia Refinery	12/14/07	Methane Reformer Heater	337 MMBtu/hr	0.0125 lb/MMBtu, 4.21 lb/hr (3-hr avg.)	SCR
IN-0180	Midwest Fertilizer Corporation	6/4/14	Reformer Furnace	950.64 MMBtu/hr	9 ppm_{vd} at 3% O_2 (30-day avg.)	SCR & LNB
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Primary Reformer**	**1,350 MMBtu/hr**	**17 ppm_{vd} at 3% O_2 0.02 lb/MMBtu (30-day avg.)**	**SCR**

RBLC Review
Most of the RBLC control method entries for reformer furnaces list the use of SCR in conjunction with GCP or LNB. Because the primary reformer at KNO is an existing unit, it would need to be retrofitted with replacement burners to achieve the maximum NOx control.

Applicant Proposal

The applicant provided an economic analysis of the installation of LNB on the primary reformer to demonstrate that the use of LNB in conjunction with SCR is not economically feasible on this unit. A summary of the analysis is shown below:

Control Alternative	Captured Emissions (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Operating Costs ($/year)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR & LNB	118.26	39.03	$3,084,996	$147,290	$586,593	$15,041
Capital Recovery Factor = 0.1424 (7% for a 10 year life cycle)						

The economic analysis indicates the level of NOx reduction does not justify installing low NOx burners to be used in conjunction with selective catalytic reduction. Based on the excessive cost per ton of NOx removed per year, installation of low NOx burners on the primary reformer is not considered a feasible option for reducing NOx emissions.

The applicant proposes the following as BACT:

(a) NOx emissions from the operation of the primary reformer (EU 12) shall be controlled by SCR at all times during operation.

(b) NOx emissions from the primary reformer shall not exceed 17 ppm_{vd} at 3% oxygen (0.02 lb/MMBtu) for a 30-day average.

(c) Compliance will be demonstrated through the use of a continuous emission monitoring system.

Step 5 – Selection of NOx BACT for the Primary Reformer
The Department agrees with the applicant that an emission rate achievable with SCR is BACT for the primary reformer. NOx emissions from the primary reformer (EU 12) shall be controlled by use of SCR and shall not exceed 17 ppm_{vd} at 3% oxygen (0.02 lb/MMBtu) for a 30-day average. Compliance with the proposed emission limit will be demonstrated through the use of a continuous emission monitoring system.

3.3 NOx BACT for the Package Boilers (EUs 44, 48, and 49)

Step 1 – Identification of NOx Control Technology for the Package Boilers
From research, the Department identified the following technologies as available for NOx control for three package boilers:

(a) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT for the turbines and will not be repeated here. The Department considers SCR a feasible control technology for package boilers.

(b) Selective Non-Catalytic Reduction
The theory of SNCR was discussed in detail in the NOx BACT for the turbines and will not be repeated here. The Department's research did not identify SNCR as a control technology used to control NOx emissions from package boilers installed at any facility. Hence the Department does not consider SNCR as a feasible control technology for the package boilers.

(c) Low NOx Burners
The theory of LNBs was discussed in detail in the NOx BACT for the turbines and will not be repeated here. The use of LNBs is a technically feasible control option for the package boilers.

(d) Ultra-Low NOx Burners
ULNBs use a similar technique as LNBs, however they also employ flue gas recirculation to lower the flame temperature and achieve lower NOx formation than from use of LNBs. The use of ULNBs is considered a technically feasible control technology for the package boilers.

(e) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of NOx. GCPs is considered a technically feasible control option for the package boilers.

Step 2 – Eliminate Technically Infeasible NOx Control Options for the Package Boilers
As explained in Section 3.3, SNCR is not feasible to control NOx emissions from the package boilers.

Step 3 – Ranking of the Remaining NOx Control Technologies for the Package Boilers
The following control technologies have been identified and ranked for the control of NOx from the package boilers.

(a) SCR and LNB (85% - 95% Control)
(b) SCR (70 - 92% Control)
(c) ULNB (50% - 90% Control)
(d) LNB (40% - 60% Control)
(e) GCP (Less than 40% Control)

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Package Boilers (EUs 44, 48, and 49) – NOx						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
NJ-0043	Liberty Generating Station	3/28/02	Auxiliary Boiler	200 MMBtu/hr	0.036 lb/MMBtu, 7.2 lb/hr (maximum)	SCR
LA-0272	Dyno Nobel Louisiana Ammonia	3/27/13	Commissioning Boilers	217.5 MMBtu/hr	0.05 lb/MMBtu (annual avg.)	ULNB & GCP
IA-0105	Iowa Fertilizer Company	10/26/12	Auxiliary Boiler	472.4 MMBtu/hr	0.0125 lb/MMBtu (30-day avg.) 5.52 ton/12 month rolling	ULNB
IN-0172	Ohio Valley Resources	9/25/13	Natural Gas-Fired Boilers	218 MMBtu/hr	0.02 lb/MMBtu (24-hr avg.)	ULNB
OK-0135	Pryor Plant Chemical Company	2/23/09	Boilers #1 & #2	80 MMBtu/hr	0.2 lb/MMBtu	LNB & GCP
IA-0079	Koch Nitrogen Company	9/8/05	Natural Gas-Fired Boiler	240 MMBtu/hr	0.06 lb/MMBtu (1-hr avg.)	ULNB
ID-0017	Southeast Idaho Energy	2/10/09	Package Boiler	250 MMBtu/hr	0.02 lb/MMBtu	ULNB
TX-0386	Amella Energy Center	3/26/02	Auxiliary Boiler	155 MMBtu/hr	0.04 lb/MMBtu, 6.2 lb/hr	None
CO-0052	Rocky Mountain Energy Center	8/11/02	Auxiliary Boiler	129 MMBtu/hr	0.038 lb/MMBtu, 1,900 hr/yr	LNB
TN-0153	Williams Refining and Marketing	4/3/12	Boiler No. 9	95 MMBtu/hr	0.084 lb/MMBtu	None
IN-0180	Midwest Fertilizer Corporation	6/4/14	Auxiliary Boiler	218.6 MMBtu/hr	20.4 lb/MMcf (3-hr avg.)	ULNB
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Package Boilers**	**243 MMBtu/hr (each)**	**0.01 lb/MMBtu (30-day rolling avg.)**	**ULNB**

RBLC Review

A review of similar units in the RBLC indicates selective catalytic reduction, low NOx burners, and ultra-low NOx burners with flue gas recirculation are the principle NOx control technologies installed on auxiliary boilers. The lowest emission rate listed in the RBLC is 0.0125 lb/MMBtu for the Iowa facility.

Applicant Proposal

The applicant proposes the following as BACT:

(a) NOx emissions from the operation of the package boilers shall be controlled with ultra-low NOx burners at all times during operation.

(b) NOx emissions from the package boilers shall not exceed 0.01 lb/MMBtu at any time.

(c) Compliance will be demonstrated through the use of a continuous emission monitoring system.

The applicant did not provide a cost estimate to install SCR on the package boilers because no appreciable emission reduction can be achieved.

Step 5 – Selection of NOx BACT for the Package Boilers
The Department agrees with the applicant that an emission rate achievable with ultra-low NOx burners is BACT for the package boilers. NOx emissions from the boilers (EUs 44, 48, and 49) shall be controlled by use of ultra-low NOx burners and shall not exceed 0.01 lb/MMBtu. Compliance will be demonstrated through the use of a NOx continuous emission monitoring system.

3.4 NOx BACT for the Waste Heat Boilers (EUs 50 through 54)

Step 1 – Identification of NOx Control Technology for the Waste Heat Boilers
From research, the Department identified the following technologies as available for NOx control for five waste heat boilers:

(a) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT for the turbines and will not be repeated here. The Department considers SCR a feasible control technology for waste heat boilers.

(b) Selective Non-Catalytic Reduction
The theory of SNCR was discussed in detail in the NOx BACT for the turbines and will not be repeated here. The Department's research did not identify SNCR used to control NOx emissions from waste heat boilers installed at any facility. Hence the Department does not consider SNCR a feasible control technology for the waste heat boilers.

(c) Low NOx Burners
The theory of LNBs was discussed in detail in the NOx BACT for the turbines and will not be repeated here. The use of LNBs is a technically feasible control option for the waste heat boilers.

(d) Ultra-Low NOx Burners
ULNBs use a similar technique as LNBs, however they also employ flue gas recirculation to lower the flame temperature and achieve lower NOx formation than from use of LNBs. The use of ULNBs is considered a technically feasible control technology for the waste heat boilers.

(e) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of NOx emissions. GCP is considered a technically feasible control option for the waste heat boilers.

Step 2 – Eliminate Technically Infeasible NOx Control Options for the Waste Heat Boilers
As explained in Section 3.4, SNCR is not feasible to control NOx emissions from the waste heat boilers.

Step 3 – Ranking of the Remaining NOx Control Technologies for the Waste Heat boilers
The following control technologies have been identified and ranked for the control of NOx from the waste heat boilers (EUs 50 through 54).

(a) SCR and LNB (85% - 95% Control)
(b) SCR (70 - 92% Control)
(c) ULNB (50% - 90% Control)
(d) LNB (40% - 60% Control)
(e) GCP (Less than 40% Control)

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Waste heat boilers (EUs 50 through 54) – NOx						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
NJ-0043	Liberty Generating Station	3/28/02	Auxiliary Boiler	200 MMBtu/hr	0.036 lb/MMBtu, 7.2 lb/hr (maximum)	SCR
LA-0272	Dyno Nobel Louisiana Ammonia	3/27/13	Commissioning Boilers	217.5 MMBtu/hr	0.05 lb/MMBtu (annual avg.)	ULNB & GCP
IA-0105	Iowa Fertilizer Company	10/26/12	Auxiliary Boiler	472.4 MMBtu/hr	0.0125 lb/MMBtu (30-day avg.) 5.52 ton/12 month rolling	ULNB
IN-0172	Ohio Valley Resources	9/25/13	Natural Gas-Fired Boilers	218 MMBtu/hr	0.02 lb/MMBtu (24-hr avg.)	ULNB
OK-0135	Pryor Plant Chemical Company	2/23/09	Boilers #1 & #2	80 MMBtu/hr	0.2 lb/MMBtu	LNB & GCP
IA-0079	Koch Nitrogen Company	9/8/05	Natural Gas-Fired Boiler	240 MMBtu/hr	0.06 lb/MMBtu (1-hr avg.)	ULNB
ID-0017	Southeast Idaho Energy	2/10/09	Package Boiler	250 MMBtu/hr	0.02 lb/MMBtu	ULNB
TX-0386	Amella Energy Center	3/26/02	Auxiliary Boiler	155 MMBtu/hr	0.04 lb/MMBtu, 6.2 lb/hr	None
CO-0052	Rocky Mountain Energy Center	8/11/02	Auxiliary Boiler	129 MMBtu/hr	0.038 lb/MMBtu, 1,900 hr/yr	LNB
TN-0153	Williams Refining and Marketing	4/3/12	Boiler No. 9	95 MMBtu/hr	0.084 lb/MMBtu	None
IN-0180	Midwest Fertilizer Corporation	6/4/14	Auxiliary Boiler	218.6 MMBtu/hr	20.4 lb/MMcf (3-hr avg.)	ULNB
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Waste heat boilers**	**50 MMBtu/hr (each)**	**7 ppm_{vd} at 15% Oxygen**	**SCR**

RBLC Review
A review of similar units in the RBLC indicates selective catalytic reduction, low NOx burners, and ultra-low NOx burners with flue gas recirculation are the principle NOx control technologies installed on auxiliary boilers. The lowest emission rate listed in the RBLC is 0.0125 lb/MMBtu for the Iowa facility. Because the waste heat boilers are existing units, they would need to be retrofitted with replacement burners to achieve the maximum NOx control.

Applicant Proposal
The applicant provided an economic analysis of the installation of LNB on the waste heat boilers to demonstrate that the use of LNB in conjunction with SCR is not economically feasible on these units. A summary of the analysis is shown below:

Control Alternative	Captured Emissions (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Operating Costs ($/year)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
LNB & SCR combined	9.85	0.89	$1,039,000	$0	$147,930	$166,213
Capital Recovery Factor = 0.1424 (7% for a 10 year life cycle)						

The economic analysis indicates the level of NOx reduction does not justify installing low NOx burners to be used in conjunction with selective catalytic reduction. Based on the excessive cost per ton of NOx removed per year, installation of low NOx burners on the waste heat boilers is not considered a feasible option for reducing NOx emissions.

The applicant proposes the following as BACT:

(a) NOx emissions from the operation of the waste heat boilers shall be controlled with SCR at all times during operation.

(b) NOx emissions from the waste heat boilers shall not exceed 0.009 lb/MMBtu, or a stack NOx emission rate of 7 ppm_{vd} at 15% oxygen.

(c) Compliance will be demonstrated through the use of a continuous emission monitoring system.

Step 5 – Selection of NOx BACT for the Waste heat boilers
The Department agrees with the applicant that an emission rate achievable with SCR is BACT for the waste heat boilers. NOx emissions from the boilers (EUs 50 through 54) shall be controlled by use of SCR and shall not exceed 0.009 lb/MMBtu, or a stack NOx emission rate of 7 ppmvd at 15% oxygen.

3.5 NOx BACT for the Startup Heater (EU 13)

Step 1 – Identification of NOx Control Technology for the Startup Heater
From research, the Department identified the following technologies as available for NOx control of startup heaters:

(a) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT for the turbines and will not be repeated here. The Department considers SCR a feasible control technology for the startup heater.

(b) Selective Non-Catalytic Reduction
The theory of SNCR was discussed in detail in the NOx BACT for the turbines and will not be repeated here. The Department's research did not identify SNCR as a control technology used to control NOx emissions from startup heaters at any facility. Hence the Department does not consider SNCR as a feasible control technology for the startup heater.

(c) Low NOx Burners
The theory of LNBs was discussed in detail in the NOx BACT for the turbines and will not be repeated here. The use of LNBs is a technically feasible control option for the startup heater.

(d) Ultra-Low NOx Burners
ULNBs use a similar technique as LNBs, however they also employ flue gas recirculation to lower the flame temperature and achieve lower NOx formation than from use of LNBs. The use of ULNBs is considered a technically feasible control technology for the startup heater.

(e) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of NOx emissions. GCPs is considered a technically feasible control option for the startup heater.

Step 2 – Eliminate Technically Infeasible NOx Control Options for the Startup Heater
As explained in Section 3.5, SNCR is not a feasible technology to control NOx emissions from the startup heater.

Step 3 – Ranking of the Remaining NOx Control Technologies for the Startup Heater
The following control technologies have been identified and ranked for the control of NOx from the startup heater.

(a) SCR (70% - 90% Control)
(b) ULNB (50% - 90% Control)
(d) LNB (40% - 60% Control)
(e) GCP (Less than 40% Control)

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Startup Heater (EU 13) – NOx						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
TX-0657	Beaumont Gas to Gasoline Plant	5/16/14	Heater	45 MMBtu/hr	0.036 lb/MMBtu 3.92 tpy	ULNB
LA-0272	Dyno Nobel Louisiana Ammonia	3/27/13	Ammonia Startup Heater	61 MMBtu/hr	10.15 lb/hr, maximum; 1.73 tpy, maximum	Good Design
IA-0105	Iowa Fertilizer Company	10/26/12	Startup Heater	110 MMBtu/hr	0.119 lb/MMBtu 3 run avg. 0.63 ton/12 month rolling	GCP
IN-0172	Ohio Valley Resources	9/25/13	Ammonia Catalyst Startup Heater	106.3 MMBtu/hr	183.7 lb/MMscf (3-hr avg.)	GCP & Fuel Type
LA-0244	Sasol N.A., Inc.	11/29/10	Startup Heater	87.3 MMBtu/hr	7.15 lb/hr, maximum	LNB
LA-0244	Sasol N.A., Inc.	11/29/10	Hot Oil Heater	170 MMBtu/hr	19.69 lb/hr, maximum	LNB
IN-0180	Midwest Fertilizer Corporation	6/4/14	Startup Heater	92.5 MMBtu/hr	183.7 lb/MMcf (3-hr avg.)	GCP & Fuel Type
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Startup Heater**	**101 MMBtu/hr**	**100 lb/MMscf**	**Limited Use**

RBLC Review
A review of similar units in the RBLC indicates low NOx burners, ultra-low NOx burners with flue gas recirculation, and good combustion practices are the principle NOx control technologies for startup heaters.

Applicant Proposal
The applicant provided an economic analysis of the installation of SCR on the startup heater to demonstrate that SCR is not economically feasible on this unit. A summary of the analysis is shown below:

Control Alternative	Captured Emissions (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Operating Costs ($/year)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	43.36	39.03	$3,048,400	$1,535,600	$2,174,200	$55,705
Capital Recovery Factor = 0.1424 (7% for a 10 year life cycle)						

The economic analysis indicates the level of NOx reduction does not justify installing selective catalytic reduction. Based on the excessive cost per ton of NOx removed per year, installation of selective catalytic reduction on the startup heater is not considered a feasible option for reducing NOx emissions.

The applicant proposes the following as BACT:

(a) NOx emissions from the operation of the startup heater shall be controlled with limited use of the unit.

(b) NOx emissions from the startup heater shall not exceed 100 lb/MMscf (0.098 lb/MMBtu).

(c) Operating hours for the startup heater shall not exceed 200 hours per year.

Step 5 – Selection of NOx BACT for the Startup Heater
The Department agrees with the applicant that an emission rate achievable with limited use is BACT for the startup heater. NOx emissions from the startup heater (EU 13) shall not exceed 100 lb/MMscf and operating hours will be limited to 200 hours per year. Compliance with the proposed emission limit will be demonstrated by recording total fuel usage and operating hours for the startup heater.

3.6 NOx BACT for the Ammonia Tank Flare and Small Flares (EUs 11, 22, and 23)

Step 1 – Identification of NOx Control Technology for the Flares
From research, the Department identified the following technologies as available for NOx control of the flares: flare work practice requirements, process flaring minimization plan (FMP); and flare gas recovery.

(a) Flare Work Practice Requirements
Flare work practice requirements can be found in 40 CFR 60.18 (c) and (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 use of proper flare design and good combustion practices are technically feasible control options for the flares.

(b) Process Flaring Minimization Plan
Process flaring minimization plans define the procedures intended to reduce the volume of gas going to the flare without compromising plant operations and safety. Process flaring minimization practices is a technically feasible control option 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 for the KNO facility is not technically feasible because the gases controlled by the flares contain ammonia and are not suitable for use in other operations or as fuel at the plant.

Step 2 – Eliminate Technically Infeasible NOx Control Options for the Flares
As explained in Section 3.6, flare gas recovery is not feasible to control NOx emissions from the flares.

Step 3 – Ranking of the Remaining NOx Control Technologies for the Flares
The following control technologies have been identified and ranked for the control of NOx from the flares:

(a) Flare Work Practice Requirements
(b) Process Flaring Minimization Plan

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Ammonia Tank Flare, Plants 4 and 5 Small and Emergency Flares (EUs 11, 22, and 23) – NOx						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
LA-0272	Dyno Nobel Louisiana Ammonia	3/27/13	Ammonia Storage Flare	0.25 MMBtu/hr pilot, 14.94 MMBtu/hr vent gas	0.04 lb/h (hourly max)	Work Practice & GCP
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	No Numeric Limit	Work Practice & GCP
IN-0172	Ohio Valley Resources	9/25/13	Ammonia Storage Flare	0.13 MMBtu/hr	0.068 lb/MMBtu (3-hr avg.), 125 lb/hr (SSM venting, 3-hr avg.)	FMP & Fuel Type
ID-0017	Southeast Idaho Energy	2/10/09	Ammonia Storage Flare	0.75 MMBtu/hr pilot	No Numeric Limit	Work Practice & GCP
AK-0076	Pt Thomson Production	8/20/12	Combustion Flares	35 MMscf/yr	0.068 lb/MMBtu	None
TX-0436	Borger Carbon Black Plant	10/03/02	Dryers, Boilers, Flare	Unspecified	0.1 lb/MMBtu	Work Practice & Design
IN-0180	Midwest Fertilizer Corporation	6/4/14	Ammonia Storage Flare	1.5 MMBtu/hr	0.068 lb/MMBtu (3-hr avg.), 125 lb/hr (SSM venting, 3-hr avg.)	FMP & Fuel Type
IN-0180	Midwest Fertilizer Corporation	6/4/14	Front End Flare	4 MMBtu/hr	0.068 lb/MMBtu (3-hr avg.), 595.49 lb/hr (SSM venting, 3-hr avg.)	FMP & Fuel Type
IN-0180	Midwest Fertilizer Corporation	6/4/14	Back End Flare	4 MMBtu/hr	0.068 lb/MMBtu (3-hr avg.), 624.94 lb/hr (SSM venting, 3-hr avg.)	FMP & Fuel Type
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Ammonia Tank Flare**	**1.25 MMBtu/hr**	**0.068 lb/MMBtu, (SSM venting, 168 hr/yr)**	**Work Practice & FMP**
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Emergency Flare**	**0.4 MMBtu/hr**	**0.068 lb/MMBtu, (SSM venting, 168 hr/yr)**	**Work Practice & FMP**
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Small Flare**	**1.25 MMBtu/hr**	**0.068 lb/MMBtu, (SSM venting, 168 hr/yr)**	**Work Practice & FMP**

RBLC Review
Most of the RBLC control method entries for flares list flare work practice requirements and good combustion practices as the principle NOx control technologies for flares. The applicant proposes the implementation of flare work practice requirements and the development of flare minimization plans as BACT for NOx emissions from the three flares.

Applicant Proposal
The applicant proposes the following as BACT:

(a) Venting to the ammonia tank flare, small flare, and emergency flare shall not exceed 168 hours each, per 12-consecutive month period.

(b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:

   (1) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable; and

   (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other maintenance events.

(c) Flare emissions shall be controlled by use of the following practices:

   (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed five minutes during any two consecutive hours;

   (2) Flares shall be operated with a flame present at all times; and

   (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(d) NOx emissions from the ammonia tank flare, small flare, and emergency flare shall not exceed 0.068 lb/MMBtu, during normal operation, based on a three-hour average.

Step 5 – Selection of NOx BACT for the Ammonia Tank Flare, Small Flare, and Emergency Flare

The Department agrees with the applicant that an emission rate achievable with flare work practice requirements and developing a flare minimization is BACT for the flares. NOx emissions from the flares (EUs 11, 22, and 23) shall be controlled through work practices and by minimizing their use, and shall not exceed 0.068 lb/MMBtu during normal operations. NOx emissions from the flares due to process gas venting shall be limited to no more than 168 hours each per rolling 12-consecutive months.

3.7 NOx BACT for the Well Pump and Fire Pump Engine (EUs 65 and 66)

Step 1 – Identification of NOx Control Technology for the Pump Engines

Stationary emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60 Subparts IIII and JJJJ, and 40 CFR 63 Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with the applicable emission limitations.

Step 2 – Eliminate Technically Infeasible NOx Control Options for the Pump Engines

The only feasible control option for the diesel-fired well pump and gasoline-fired fire pump engines is good combustion practices.

Step 3 – Ranking of the Remaining NOx Control Technologies for the Pump Engines

The applicant has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls

The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Diesel-Fired Well Pump and Gasoline-Fired Fire Pump Engines (EUs 65 and 66) – NOx						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
SC-0113	Pyramax Ceramics	2/8/12	Fire Pump	500 hp	4.0 g/kW-hr	40 CFR 60, Subpart IIII
ID-0018	Idaho Power Company	6/25/10	Fire Pump Engine	235 kW	4.0 g/kW-hr	Tier 3 Engine & GCP
LA-0251	Flopam, Inc.	4/26/11	Fire Pump Engines	444 hp	3.0 g/kW-hr, 5.82 lb/hr, 0.29 tpy	None
ID-0017	Southeast Idaho Energy	2/10/09	Emergency Generator, Fire Pump	500 kW	None	GCP
IN-0172	Ohio Valley Resources	9/25/13	Diesel-Fired Emergency Water Pump	481bhp	2.89 g/hp-hr (3-hr avg.)	GCP
IA-0105	Iowa Fertilizer Company	10/26/12	Fire Pump	235 kW	3.75 g/kW-hr (3 stack test avg.), 0.49 tpy	GCP
OH-0254	Duke Energy Washington County	8/14/13	Fire Pump Engine	400 hp	14.5 g/hp-hr, 12.8 lb/hr, 3.2 tpy	Combustion Control
IN-0180	Midwest Fertilizer Company	6/4/14	Fire Pump	500 hp	2.83 g/hp-hr (3-hr avg.)	GCP

AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Diesel-Fired Well Pump Engine**	**2.7 MMBtu/hr**	**4.41 lb/MMBtu**	**Limited Use**
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Gasoline-Fired Fire Pump Engine**	**2.1 MMBtu/hr**	**1.63 lb/MMBtu**	**Limited Use**

RBLC Review
A review of similar units in the RBLC indicates good combustion practices are the principle NOx control technologies for both diesel-fired and gasoline-fired pump engines.

Applicant Proposal
The applicant proposes the following as BACT:

(a) NOx emissions from the operation of the diesel-fired well pump and gasoline-fired fire water pump shall be controlled with limited use of the units.

(b) NOx emissions from the diesel-fired well pump shall not exceed 4.41 lb/MMBtu.

(c) NOx emissions from the gasoline-fired fire water pump shall not exceed 1.63 lb/MMBtu.

(d) Operating hours for EUs 65 and 66 shall not exceed 168 hours per 12-consecutive month period, each.

Step 5 – Selection of NOx BACT for the Well Pump and Fire Water Pump Engines
The Department agrees with the applicant that an emission rate achievable with limited use is BACT for the pump engines. NOx emissions from the diesel-fired well pump engine (EU 65) and the gasoline-fired fire pump engine (EU 66) shall not exceed 4.41 lb/MMBtu and 1.63 lb/MMBtu, respectively, and operating hours will be limited to 168 hours per year each. Compliance with the proposed emission limit will be demonstrated by recording and reporting the operating hours for the pump engines.

4.0 BACT Determination for CO
The KNO facility has five existing 37.6 MMBtu/hr Solar Centaur GSC-4000 turbines that burn natural gas, one 1,350 MMBtu/hr primary reformer, heaters, boilers, flares, and several other EUs subject to BACT. The Department reviewed the control technologies Agrium identified in their application and determined CO BACT for the EUs listed in Table B-1.

The Department based its assessment on BACT determinations found in the RBLC and internet research. Table B-3 summarizes CO BACT determinations in the RBLC for the proposed EUs.

Table B-3: CO BACT Determinations in RBLC for January 2004-August 8, 2014

Description of NOx BACT	Fuel Gas Turbines	Primary Reformer	Startup Heater	Boilers	Flares	Well and Fire Pump	CO2 Vent
Good Combustion Practices		3	3	6	3	4	
Good Operating Practices			2		3		3
Clean Fuels		2				2	
Oxidation Catalyst	2			2			2
Limit Hours of Operation							
Emission Unit Design				1	5		
Thermal Oxidizer							1
Total	**2**	**5**	**5**	**9**	**11**	**6**	**6**

4.1 CO BACT for the Turbines (EUs 55 through 59)

Step 1- Identification of CO Control Technology for the Turbines
From research, the Department identified the following technologies as available for CO control of turbines rated at 25 MW or less: oxidation catalyst, good combustion practices, and fuel specifications.

(a) Oxidation Catalyst
The primary CO control method used in combustion turbines is catalytic oxidation. In fact, some SCR units incorporate CO oxidation modules to reduce CO and NOx simultaneously. CO catalysts oxidize CO and hydrocarbon compounds to carbon dioxide and water vapor. The reaction is spontaneous and no reactants are required. CO catalysts on gas turbines can achieve up to 90% reduction in CO emissions. Therefore, catalytic oxidation is a technically feasible control option of the open-simple cycle combustion turbines with heat recovery.

(b) Good Combustion Practices
The theory of good combustion practices was discussed in detail in the NOx BACT for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of CO. Therefore good combustion practices is a feasible control option for the turbines.

(c) Fuel Specifications
Selection of low carbon fuel will reduce the amount of carbon available for the conversion to CO. Therefore, fuel specifications are a feasible CO control option for the combustion turbines.

Step 2 - Elimination of Technically Infeasible CO Control Options for Turbines
As explained in Section 4.1, catalytic oxidation, good combustion practices, and fuel specifications are all technically feasible options to control CO emissions from turbines smaller than 25 MW.

Step 3 - Ranking of Remaining CO Control Technologies for Turbines
The following control technologies have been identified and ranked for control of CO from the turbines.

(a) Oxidation Catalyst (90% Control)
(b) Good Combustion Practices (less than 90% Control)
(c) Fuel Specifications (minimal reduction)

Step 4 - Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units (combustion turbines rated at less than 25 MW). All data in this table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Solar Combustion Turbines (EUs 55 through 59) – CO						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
AK-0066	BP-Endicott	6/15/09	Gas Turbine	7.5 MW	5 ppm_{vd} at 15% O_2 T ≥ 10 ºF 15 ppm_{vd} at 15% O_2 T < 10 ºF	Catalytic Oxidation
CT-0155	Wesleyan University	8/27/08	Gas Turbine	22.3 MMBtu/hr	0.48 g/hp-hr 15.51 tpy	Catalytic Oxidation
PA-0289	Geisinger Medical Center	6/18/10	Gas Turbine	55.62 MMBtu/hr	25 ppm at 15% O_2 (in SoLoNOx) 100 ppm at 15% O_2 (in Sub-Zero, Non-SoLoNOx)	None
WY-0067	Echo Springs Gas Plant	4/1/09	Gas Turbine	12,555 hp	25 ppm_{vd} 26 tpy	GCP
WY-0067	Echo Springs Gas Plant	4/1/09	Gas Turbine	16,162 hp	25 ppm_{vd} 32.5 tpy	GCP
WY-0067	Echo Springs Gas Plant	4/1/09	Gas Turbine	3,856 hp	50 ppm_{vd} 19.3 tpy	GCP
IN-0180	Midwest Fertilizer Corporation	6/4/14	Two Gas Turbine	283 MMBtu/hr (each)	0.03 lb/MMBtu (3-hr avg.) > 50% load	GCP & Design
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Five Gas Combustion Turbines**	**37.6 MMBtu/hr (each)**	50 ppm_{vd} at 15% O_2	None

RBLC Review
A review of similar units in the RBLC indicates catalytic oxidation and good combustion practices are the principle CO control technologies installed on gas turbines smaller than 25 MW.

Applicant Proposal
The applicant provided an economic analysis of the installation of catalytic oxidation on the turbines to demonstrate that the use of catalytic oxidation is not economically feasible on these units. A summary of the analysis is shown below:

Control Alternative	Captured Emissions (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Operating Costs ($/year)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	41.85	37.7	$1,386,700	$277,600	$408,504	$10,836
Capital Recovery Factor = 0.0944 (7% for a 20 year life cycle)						

[1] Economic analysis for installing catalytic oxidation on one turbine with waste heat recovery boiler
[2] Revised to indicate a CO control efficiency of 90% as indicated in Step 3 of the top-down BACT approach.

The economic analysis indicates the level of CO reduction does not justify the use of catalytic oxidation. Based on the excessive cost per ton of CO removed per year, installing catalytic oxidation on the turbines/waste heat boilers is not considered a feasible option for reducing CO emissions.

The applicant proposes the following as BACT:

(a) CO emissions from the turbines at the waste heat boiler outlet shall not exceed 50 ppm_{vd} at 15% oxygen, equivalent to a CO emission limit of 0.109 lb/MMBtu.

(b) Compliance with the proposed emission limit will be demonstrated by conducting an initial stack test to obtain an emission rate.

Step 5 – Selection of CO BACT for Turbines

The Department agrees with the applicant that an emission rate achievable with no controls is BACT for the turbines. CO emissions from each of the natural gas fired combustion turbines (EUs 55 through 59) shall not exceed 50 ppm_{vd} at 15% oxygen. For the Solar Turbines, this will be equivalent to a CO emission limit of 0.109 lb/MMBtu.

4.2 CO BACT for the Primary Reformer (EU 12)

Step 1 – Identification of CO Control Technology for the Primary Reformer

From research, the Department identified the following technologies as available for CO control of reformer furnaces:

(a) Thermal Oxidizers

The thermal oxidizer has a stabilized flame maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, nevertheless it is also considered as a technology for controlling CO emissions. Upon passing through the flame, the gas containing CO is heated from its inlet temperature to its ignition temperature (the temperature at which the combustion reaction rate (and consequently the energy production rate) exceeds the rate of heat losses, thereby raising the temperature of the gases to some higher value). Thus, any CO/air mixture will ignite if its temperature is raised to a sufficiently high level. The CO-containing mixture ignites at some temperature between the preheat temperature and the reaction temperature. The ignition occurs at some point during the heating of a waste stream. The mixture continues to react as it flows through the combustion chamber.

Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 °F to 2,000 °F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the level of control. Regenerative thermal oxidizers consists of direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.

The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed) to its ignition temperature. The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it to the combustion chamber outlet temperature. The process flows are then switched, feeding the inlet stream to the hot bed. This cyclic process affords high energy recovery (up to 95%). The higher capital costs associated with these high-performance heat exchangers and combustion chambers may be offset by the auxiliary fuel savings to make such a system economical.

The use of a regenerative thermal oxidizer is not a technically feasible control option for the reformer furnace; because, the exhaust stream is comprised of natural gas combustion products with extremely low heating value. Thermal oxidizers have not been installed on natural gas combustion sources to control CO.

(b) Catalytic Oxidizers
Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors; nevertheless it is considered a technology for controlling CO emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures (compared to thermal oxidation) without the catalyst undergoing change itself. Catalytic oxidizers operate at 650°F to 1000°F and require approximately 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 gas flow.

Emissions from some emission units may contain significant amount of particulates. These particulates can poison the catalyst resulting in the failure of catalytic oxidation. For some fuels, such as coal and residual oil, contaminants would likely be present in such concentrations so as to foul catalysts quickly thereby making such systems infeasible due to the need to constantly replace catalyst materials. In addition, the use of oxidation catalysts on units with high sulfur fuels can also result in the creation of sulfuric acid mist through the conversion of SO_2 to SO_3 and subsequent combination with moisture in the exhaust gas. The use of an oxidation catalyst to control carbon monoxide emissions is feasible for gas fired units because the fuel is a low sulfur fuel with relatively low concentrations of other contaminants, such as metals. The use of a catalytic oxidizer is a technically feasible control option for the reformer furnace.

(c) Flare
The low heating value of the reformer furnace exhaust is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of a flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NOx. Flares have not been utilized or demonstrated as a control device for CO from this type of high-volume process stream. The use of a flare is not a technically feasible option for the reformer furnace.

(d) Good Combustion Practices
The theory of good combustion practices was discussed in detail in the NOx BACT for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of CO. Therefore good combustion practices is a feasible control option for the reformer furnace.

Step 2 – Eliminate Technically Infeasible CO Control Options for the Primary Reformer
As explained in Section 4.2, thermal oxidizers are not a feasible control technology to reduce CO emissions from the reformer furnace.

Step 3 – Ranking of the Remaining CO Control Technologies for the Primary Reformer
The following control technologies have been identified and ranked for the control of CO from the primary reformer.

(a) Oxidation Catalyst (75% Control)
(b) Good Combustion Practices (less than 75% Control)

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Primary Reformer (EU 12) – CO						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
TX-0657	Beaumont Gas to Gasoline Plant	5/16/14	Primary Reformer	1,552 MMBtu/hr	50 ppm (annual) 177.4 tpy	GCP
LA-0272	Dyno Nobel Louisiana Ammonia	3/27/13	Primary Reformer	956.2 MMBtu/hr	49.16 lb/hr (max) 179.43 tpy	GCP & Design
IA-0105	Iowa Fertilizer Company	10/26/12	Primary Reformer	1,152.6 MMBtu/hr	0.0194 lb/MMBtu (3 test run avg.) 96.3 tpy	GCP
IA-0106	CF Industries Nitrogen, LLC	7/12/13	Primary Reformer	1062.6 MMBtu/hr	0.0194 lb/MMBtu (3 test run avg.) 90.3 tpy	GCP & Fuel Type
IN-0172	Ohio Valley Resources	9/25/13	Primary Reformer	1,006.4 MMBtu/hr	43.45 lb/MMcf (3-hr avg.)	GCP

OK-0134	Pryor Plant Chemical Company	2/23/09	Primary Reformer	700 ton ammonia per day	18.53 lb/hr (1-hr / 8-hr)	GCP
LA-0211	Garyville Refinery	12/27/06	Hydrogen Reformer	1,412.5 MMBtu/hr	0.04 lb/MMBtu (30-day avg.)	GCP & Design
NM-0050	Artesia Refinery	12/14/07	Methane Reformer Heater	337 MMBtu/hr	0.06 lb/MMBtu (3-hr avg.), 20.22 lb/hr (3-hr avg.)	Fuel Type
IN-0180	Midwest Fertilizer Corporation	6/4/14	Reformer Furnace	950.64 MMBtu/hr	43.45 lb/MMcf (3-hr avg.)	GCP & Design
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Primary Reformer**	**1,350 MMBtu/hr**	**43.45 lb/MMcf (3-hr avg.)**	**None**

RBLC Review
A review of the RBLC control method entries for reformer furnaces indicates no add-on control technology for CO has been utilized and proven cost effective. Review of a similar BACT analysis performed by Midwest Fertilizer Corporation found the cost of installing catalytic oxidation on a reformer furnace is around $77,000 per ton of CO removed, based on a 75% emission reduction (133 tpy). Therefore, the Department agrees with the applicant that the use of a catalytic oxidizer to reduce CO emissions for this emission unit is not cost effective.

Applicant Proposal
The applicant proposes the following as BACT:

(a) CO emissions from the primary reformer shall not exceed 43.45 lb/MMcf (0.0426 lb/MMBtu) for a 3-hour average.

(b) Compliance with the proposed emission limit will be demonstrated by conducting an initial stack test to obtain an emission rate.

The applicant's proposal is consistent with the majority of entries in the RBLC for CO. These emission limits are based on the uncontrolled emission factors found in AP-42. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0194 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. The Department believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

(a) Add-on emission controls have been demonstrated to be infeasible or not cost-effective.

(b) The majority of entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.

(c) The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT.

(1) Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.

(2) IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

The Department believes BACT for natural gas-fired combustion in the reformer is 43.45 lb/MMcf for CO.

Step 5 – Selection of CO BACT for the Primary Reformer
The Department agrees with the applicant that an emission rate achievable with no controls is BACT for the primary reformer. CO emissions from the primary reformer (EU 12) shall not exceed 43.45 lb/MMcf (0.0426 lb/MMBtu) for a 3-hour average. Initial compliance with the proposed emission limit will be demonstrated by conducting a stack test.

4.3 CO BACT for the Package Boilers (EUs 44, 48, and 49)

Step 1 – Identification of CO Control Technology for the Package Boilers
From research, the Department identified the following technologies as available for CO control for package boilers:

(a) Thermal Oxidizers
The theory of thermal oxidizers was discussed in detail in the CO BACT for the primary reformer and will not be repeated here. The use of a regenerative thermal oxidizer is not a technically feasible control option for the package boilers because the exhaust stream is comprised of natural gas combustion products with extremely low heating value. Thermal oxidizers have not been installed on natural gas combustion sources to control CO.

(b) Catalytic Oxidizers
The theory of catalytic oxidizers was discussed in detail in the CO BACT for the primary reformer and will not be repeated here. The use of an oxidation catalyst to control carbon monoxide emissions is feasible for gas fired units because the fuel is a low sulfur fuel with relatively low concentrations of other contaminants, such as metals. The use of a catalytic oxidizer is a technically feasible control option for the package boilers.

(c) Flare
Flares are another form of thermal oxidation. Theoretically, carbon monoxide is combined with additional fuel to raise the exhaust gas temperature to a level where it is converted to carbon dioxide and water vapor. As with the thermal oxidizer, flares are not typically installed on natural gas combustion sources to achieve a reduction in carbon monoxide. The combustion of additional fuel to raise the temperature of the exhaust gas to at least 1,100 °F will result in an increase in other regulated pollutants. While technologically feasible, it is not a feasible control option for the package boilers.

(d) Good Combustion Practices
The theory of good combustion practices was discussed in detail in the NOx BACT for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of CO. Therefore good combustion practices is a feasible control option for the package boilers.

Step 2 – Eliminate Technically Infeasible CO Control Options for the Package Boilers
As explained in Section 4.3, thermal oxidizers and flares are technically infeasible CO control options for use on auxiliary boilers.

Step 3 – Ranking of the Remaining CO Control Technologies for the Package Boilers
The following control technologies have been identified and ranked for the control of CO from the package boilers.

(a) Oxidation Catalyst (75% Control)
(b) Good Combustion Practices (Less than 75% Control)

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Package Boilers (EUs 44, 48, and 49) – CO						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
AR-0094	John W. Turk Jr. Power Plant	11/5/08	Auxiliary Boiler	555 MMBtu/hr	0.036 lb/MMBtu (30-day rolling avg.)	None
NJ-0043	Liberty Generating Station	3/28/02	Auxiliary Boiler	200 MMBtu/hr	100 ppm_{vd} @ 7% O_2, l7.4 lb/hr, 0.087 lb/MMBtu	CO Catalyst
LA-0179	Union Carbide Corporation	6/27/05	Two Package Boilers	370 MMBtu/hr (each)	32.12 lb/hr (max) 133.46 tpy 0.082 lb/MMBtu (annual avg.)	None
LA-0272	Dyno Nobel Louisiana Ammonia	3/27/13	Commissioning Boilers	217.5 MMBtu/hr	10.87 lb/hr (max) 19.93 tpy	GCP & Design
IA-0105	Iowa Fertilizer Company	10/26/12	Auxiliary Boiler	472.4 MMBtu/hr	0.0013 lb/MMBtu (3 stack test avg.) 0.57 tpy	GCP
IN-0172	Ohio Valley Resources	9/25/13	Natural Gas-Fired Boilers	218 MMBtu/hr	37.22 lb/MMcf (3-hr avg.)	GCP & Design
OH-0310	American Municipal Power	10/8/9	Auxiliary Boiler	150 MMBtu/hr	12.6 lb/hr 5.52 tpy 400 ppm_{vd} @ 3% O_2 (3-hr avg.)	None
OK-0135	Pryor Plant Chemical Company	2/23/09	Boilers 1 & 2	80 MMBtu/hr	6.6 lb/hr (1-hr / 8-hr)	GCP

IA-0079	Koch Nitrogen Company	9/8/05	Natural Gas-Fired Boiler	240 MMBtu/hr	0.06 lb/MMBtu (1-hr avg.)	ULNB
ID-0017	Southeast Idaho Energy	2/10/09	Package Boiler	250 MMBtu/hr	0.074 lb/MMBtu 18.5 lb/hr	GCP
TX-0386	Amella Energy Center	3/26/02	Auxiliary Boiler	155 MMBtu/hr	13.9 lb/hr 0.08 lb/MMBtu	Unknown
TX-0641	Pinecrest Energy Center	11/12/13	Auxiliary Boiler	150 MMBtu/hr	75 ppm_{vd} at 3% O_2	GCP
CO-0052	Rocky Mountain Energy Center	8/11/02	Auxiliary Boiler	129 MMBtu/hr	0.039 lb/MMBtu	GCP
TN-0153	Williams Refining and Marketing	4/3/12	Boiler No. 9	95 MMBtu/hr	0.09 lb/MMBtu	Unknown
IN-0180	Midwest Fertilizer Corporation	6/4/14	Three Auxiliary Boiler	218.6 MMBtu/hr (each)	37.22 lb/MMcf (3-hr avg.)	GCP & Design
WY-0074	Green River Soda Ash Plant	11/18/13	Natural Gas Package Boiler	254 MMBtu/hr	0.037 lb/MMBtu (30-day rolling), 9.4 lb/hr (30-day rolling)	GCP
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Package Boilers**	**243 MMBtu/hr**	**50 ppm_{vd} at 3% O_2 (0.037 lb/MMBtu)**	**None**

RBLC Review

A review of similar units in the RBLC indicates add-on controls are not typically employed on natural gas combustion sources. Most of the RBLC entries used the AP-42 emission factor for open combustion of natural gas, the Iowa Fertilizer Corporation (IFC) and American Municipal Power, however did not. American Municipal Power used a higher emission rate. The IFC boiler used a much lower emission rate.

Applicant Proposal

The applicant provided an economic analysis of the installation of catalytic oxidation on the boilers to demonstrate that the use of catalytic oxidation is not economically feasible on these units. A summary of the analysis is shown below:

Control Alternative	Captured Emissions (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Operating Costs ($/year)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	39.4	39	$4,420,100	$1,093,700	$1,510,957	$38,743
Capital Recovery Factor = 0.0944 (7% for a 20 year life cycle)						

The economic analysis indicates the level of CO reduction does not justify the use of catalytic oxidation. Based on the excessive cost per ton of CO removed per year, installing catalytic oxidation on the package boilers is not considered a feasible option for reducing CO emissions.

The applicant proposes the following as BACT:

(a) CO emissions from the package boilers shall not exceed 50 ppm_{vd} at 3% O_2 (0.037 lb/MMBtu).

(b) Compliance with the proposed emission limit will be demonstrated by conducting an initial stack test to obtain an emission rate.

Step 5 – Selection of CO BACT for the Package Boilers

The Department agrees with the applicant that an emission rate achievable with no controls is BACT for the package boilers. CO emissions from the package boilers (EUs 44, 48, and 49) shall not exceed 50 ppm_{vd} at three percent oxygen (0.037 lb/MMBtu). Initial compliance with the proposed emission limit will be demonstrated by conducting an initial stack test.

4.4 CO BACT for the Waste Heat Boilers (EUs 50 through 54)

Step 1 – Identification of CO Control Technology for the Waste Heat Boilers

From research, the Department identified the following technologies as available for CO control for five waste heat boilers:

(a) Thermal Oxidizers

The theory of thermal oxidizers was discussed in detail in the CO BACT for the primary reformer and will not be repeated here. The use of a regenerative thermal oxidizer is not a technically feasible control option for the waste heat boilers because the exhaust stream is comprised of natural gas combustion products with extremely low heating value. Thermal oxidizers have not been installed on natural gas combustion sources to control CO.

(b) Catalytic Oxidizers

The theory of catalytic oxidizers was discussed in detail in the CO BACT for the primary reformer and will not be repeated here. The use of an oxidation catalyst to control carbon monoxide emissions is feasible for gas fired units because the fuel is a low sulfur fuel with relatively low concentrations of other contaminants, such as metals. However the use of a catalytic oxidizer is not a technically feasible control option for the waste heat boilers due to the high level of excess air from the combustion turbines.

(c) Flare

Flares are another form of thermal oxidation. Theoretically, carbon monoxide is combined with additional fuel to raise the exhaust gas temperature to a level where it is converted to carbon dioxide and water vapor. As with the thermal oxidizer, flares are not typically installed on natural gas combustion sources to achieve a reduction in carbon monoxide. The combustion of additional fuel to raise the temperature of the exhaust gas to at least 1,100 °F will result in an increase in other regulated pollutants. While technologically feasible, it is not a feasible control option for the waste heat boilers.

(d) Good Combustion Practices

The theory of good combustion practices was discussed in detail in the NOx BACT for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of CO. Therefore good combustion practices is a feasible control option for the waste heat boilers.

Step 2 – Eliminate Technically Infeasible CO Control Options for the Waste Heat Boilers
As explained in Section 4.4, thermal oxidizers, catalytic oxidizers, and flares are technically infeasible CO control options for use on auxiliary boilers.

Step 3 – Ranking of the Remaining CO Control Technologies for the Waste Heat boilers
The applicant has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Waste heat boilers (EUs 50 through 54) – CO						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
NJ-0043	Liberty Generating Station	3/28/02	Auxiliary Boiler	200 MMBtu/hr	0.036 lb/MMBtu, 7.2 lb/hr, (maximum)	SCR
LA-0272	Dyno Nobel Louisiana Ammonia	3/27/13	Commissioning Boilers	217.5 MMBtu/hr	0.05 lb/MMBtu (annual avg.)	ULNB & GCP
IA-0105	Iowa Fertilizer Company	10/26/12	Auxiliary Boiler	472.4 MMBtu/hr	0.0125 lb/MMBtu (30-day avg.) 5.52 ton/12 month rolling	ULNB
IN-0172	Ohio Valley Resources	9/25/13	Natural Gas-Fired Boilers	218 MMBtu/hr	0.02 lb/MMBtu (24-hr avg.)	ULNB
OH-0310	American Municipal Power	10/8/9	Auxiliary Boiler	150 MMBtu/hr	12.6 lb/hr 5.52 tpy 400 ppm_{vd}@ 3% O_2 (3-hr avg.)	None
OK-0135	Pryor Plant Chemical Company	2/23/09	Boilers #1 & #2	80 MMBtu/hr	0.2 lb/MMBtu	LNB & GCP
IA-0079	Koch Nitrogen Company	9/8/05	Natural Gas-Fired Boiler	240 MMBtu/hr	0.06 lb/MMBtu (1-hr avg.)	ULNB
ID-0017	Southeast Idaho Energy	2/10/09	Package Boiler	250 MMBtu/hr	0.02 lb/MMBtu	ULNB
TX-0386	Amella Energy Center	3/26/02	Auxiliary Boiler	155 MMBtu/hr	0.04 lb/MMBtu, 6.2 lb/hr	None
TX-0641	Pinecrest Energy Center	11/12/13	Auxiliary Boiler	150 MMBtu/hr	75 ppm_{vd} at 3% O_2	GCP
CO-0052	Rocky Mountain Energy Center	8/11/02	Auxiliary Boiler	129 MMBtu/hr	0.038 lb/MMBtu, 1,900 hr/yr	LNB
TN-0153	Williams Refining and Marketing	4/3/12	Boiler No. 9	95 MMBtu/hr	0.084 lb/MMBtu	None

IN-0180	Midwest Fertilizer Corporation	6/4/14	Auxiliary Boiler	218.6 MMBtu/hr	20.4 lb/MMcf (3-hr avg.)	ULNB
WY-0074	Green River Soda Ash Plant	11/18/13	Natural Gas Package Boiler	254 MMBtu/hr	0.037 lb/MMBtu (30-day rolling) 9.4 lb/hr (30-day rolling)	GCP
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Waste heat boilers**	**50 MMBtu/hr (each)**	**50 ppm$_{vd}$ at 15% O_2**	**None**

RBLC Review
A review of similar units in the RBLC indicates add-on controls are not typically employed on natural gas combustion sources. Most of the RBLC entries used the AP-42 emission factor for open combustion of natural gas, the Iowa Fertilizer Corporation (IFC) and American Municipal Power, however did not. American Municipal Power used a higher emission rate. The IFC boiler used a much lower emission rate.

Applicant Proposal
The applicant proposes the following as BACT:

(b) CO emissions from the waste heat boilers shall not exceed 50 ppm$_{vd}$ at 15% O_2 (0.109 lb/MMBtu).

(c) Compliance with the proposed emission limit will be demonstrated by conducting an initial stack test to obtain an emission rate.

Step 5 – Selection of CO BACT for the Waste heat boilers
The Department agrees with the applicant that an emission rate achievable with no controls is BACT for the waste heat boilers. CO emissions from the boilers (EUs 50 through 54) shall not exceed 0.109 lb/MMBtu, or a stack CO emission rate of 50 ppm$_{vd}$ at 15% oxygen.

4.5 CO BACT for the Startup Heater (EU 13)

Step 1 – Identification of CO Control Technology for the Startup Heater
From research, the Department identified the following technologies as available for CO control of startup heaters:

(a) Thermal Oxidizers
The theory of thermal oxidizers was discussed in detail in the CO BACT for the primary reformer and will not be repeated here. The use of a regenerative thermal oxidizer is not a technically feasible control option for the startup heater because the exhaust stream is comprised of natural gas combustion products with extremely low heating value. Thermal oxidizers have not been installed on natural gas combustion sources to control CO.

(b) Catalytic Oxidizers
The theory of catalytic oxidizers was discussed in detail in the CO BACT for the primary reformer and will not be repeated here. The use of an oxidation catalyst to control carbon monoxide emissions is feasible for gas fired units because the fuel is a low sulfur fuel with relatively low concentrations of other contaminants, such as metals. However the use of a catalytic oxidizer is not a technically feasible control option for the startup heater because of the low excess oxygen level and the limited use of the heater.

(c) Flares
The theory of operation of flares was discussed in detail under the CO BACT for the reformer furnace and will not be repeated here. The heating value of the startup heater's exhaust is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of a flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NOx. Flares have not been utilized or demonstrated as a control device for CO from this type of high-volume process stream. The use of a flare is a technically infeasible option for the startup heater.

(d) Good Combustion Practices
The theory of good combustion practices was discussed in detail in the NOx BACT for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of CO. Therefore good combustion practices is a feasible control option for the startup heater.

Step 2 – Eliminate Technically Infeasible CO Control Options for the Startup Heater
As explained in Section 4.5, thermal oxidizers are not a feasible control technology to reduce CO emissions from the startup heater

Step 3 – Ranking of the Remaining CO Control Technologies for the Startup Heater
The following control technologies have been identified and ranked for the control of CO from the startup heater.

(a) Oxidation Catalyst (75% Control)
(b) Good Combustion Practices (less than 75% Control)

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Startup Heater (EU 13) – CO						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
TX-0657	Beaumont Gas to Gasoline Plant	5/16/14	Heater	45 MMBtu/hr	50 ppm (annual) 3.45 tpy	GCP
LA-0272	Dyno Nobel Louisiana Ammonia	3/27/13	Ammonia Startup Heater	61 MMBtu/hr	2.97 lb/hr (max) 0.62 tpy	GCP & Good Design
IA-0105	Iowa Fertilizer Company	10/26/12	Startup Heater	110 MMBtu/hr	0.0194 lb/MMBtu 0.1 tpy	GCP
IN-0172	Ohio Valley Resources	9/25/13	Ammonia Catalyst Startup Heater	106.3 MMBtu/hr	37.23 lb/MMcf (3-hr avg.)	GCP & Fuel Type
WY-0067	Williams Field Services	4/1/09	Hot Oil Heater	84 MMBtu/hr	0.02 lb/MMBtu 7.4 tpy	GCP
MD-0035	Dominion Cove Pt.	8/12/05	Vaporization Heater	88.4 MMBtu/hr	0.03 lb/MMBtu	GCP & Fuel Type
OK-0136	Conoco Phillips	2/9/09	Crude Heater	125 MMBtu/hr	5 lb/hr 21.9 tpy	LNB & GCP
MN-0070	Minnesota Steel Industries	9/7/07	Process Heaters	606 MMBtu/hr	0.08 lb/MMBtu 50 lb/hr (1 hour rolling avg.)	None
IN-0180	Midwest Fertilizer Corporation	6/4/14	Startup Heater	92.5 MMBtu/hr	37.23 lb/MMcf	GCP, Design, & Fuel Type
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Startup Heater**	**101 MMBtu/hr**	**84 lb/MMscf**	**Limited Use**

RBLC Review
A review of similar units in the RBLC indicates add-on control technology is not practical for natural gas-fired process heaters. CO emissions are controlled with limited use of the startup heater. As discussed in the CO BACT for the primary reformer, catalytic oxidation is not a cost effective control technology for the primary reformer. Because of the lower utilization of the startup heater and lower CO emissions, it is even less cost effective for the startup heater.

Applicant Proposal
The applicant proposes the following as BACT:

(a) CO emissions from the operation of the startup heater shall be controlled with limited use of the unit.

(b) CO emissions from the startup heater shall not exceed 84 lb/MMscf (0.082 lb/MMBtu).

(c) Operating hours for the startup heater shall not exceed 200 hours per year.

The applicant's proposal is consistent with a majority of the entries in the RBLC for CO emissions. The applicant's proposed emission limits are based on the uncontrolled emission factors found in AP-42. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0194 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. The Department believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

(a) Add-on emission controls have been demonstrated to be infeasible or not cost-effective.

(b) The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.

(c) The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT.

  (1) Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.

  (2) IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

The next lowest entry in the RBLC for CO from a startup heater is 0.02 lb/MMBtu from the Williams Field Services Oil Heater in Wyoming. If the applicant accepted the lower emission rate without the limit on the hours of operation, the startup heater would emit 8.8 tons CO per year. If the applicant's proposal of 0.082 lb/MMBtu with a 200 hour per year operational limit is accepted, the startup heater would emit 0.83 tons of CO per year. With 0.83 ton/year of CO emissions, add-on controls needed to achieve 0.02 lb CO/MMBtu is not cost effective. While the hourly emission rate would be lower at 0.02 lb CO/MMBtu, the applicant's proposal represents an overall lower annual emission rate and represents BACT for this unit.

Step 5 – Selection of CO BACT for the Startup Heater

The Department agrees with the applicant that an emission rate achievable with limited use is BACT for the startup heater. CO emissions from the startup heater (EU 13) shall not exceed 84 lb/MMscf (0.082 lb/MMBtu) and operating hours will be limited to 200 hours per year. Compliance with the proposed emission limit will be demonstrated by recording total fuel usage and operating hours for the startup heater.

4.6 CO BACT for the Ammonia Tank Flare and Small Flares (EUs 11, 22, and 23)

Step 1 – Identification of CO Control Technology for the Flares
From research, the Department identified the following technologies as available for CO control of the flares: flare work practice requirements, process flaring minimization plan; and flare gas recovery.

(a) Flare Work Practice Requirements
Flare work practice requirements can be found in 40 CFR 60.18 (c) and (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 use of proper flare design and good combustion practices are technically feasible control options for the flares.

(b) Process Flaring Minimization Plan
Process flaring minimization plans define the procedures intended to reduce the volume of gas going to the flare without compromising plant operations and safety. Process flaring minimization practices is a technically feasible control option 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 for the KNO facility is not technically feasible because the gases controlled by the flares contain ammonia and are not suitable for use in other operations or as fuel at the plant.

Step 2 – Eliminate Technically Infeasible CO Control Options for the Flares
As explained in Section 4.6, flare gas recovery is not feasible to control CO emissions from the flares.

Step 3 – Ranking of the Remaining CO Control Technologies for the Flares
The following control technologies have been identified and ranked for the control of CO from the flares.

(a) Flare Work Practice Requirements
(b) Process Flaring Minimization Plan

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Ammonia Tank Flare, Plants 4 and 5 Small and Emergency Flares (EUs 11, 22, and 23) – CO						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
LA-0272	Dyno Nobel Louisiana Ammonia	3/27/13	Ammonia Storage Flare	0.25 MMBtu/hr pilot, 14.94 MMBtu/hr vent gas	0.2 lb/hr (hourly max) 0.71 tpy (max)	Work Practice & GCP
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Work Practice & GCP
IN-0172	Ohio Valley Resources	9/25/13	Ammonia Storage Flare	0.13 MMBtu/hr	0.37 lb/MMBtu, 3,240.16 lb/hr (SSM venting 3-hr avg.)	FMP & Fuel Type
ID-0017	Southeast Idaho Energy	2/10/09	Ammonia Storage Flare	0.75 MMBtu/hr pilot	No emissions from process, no limit on pilot	Work Practice & GCP
AK-0076	Pt Thomson Production	8/20/12	Combustion Flares	35 MMscf/yr	0.37 lb/MMBtu	None
IN-0180	Midwest Fertilizer Corporation	6/4/14	Ammonia Storage Flare	1.5 MMBtu/hr	0.37 lb/MMBtu (SSM venting limited to 168 hr)	FMP & Fuel Type
IN-0180	Midwest Fertilizer Corporation	6/4/14	Front End Flare	4 MMBtu/hr	0.37 lb/MMBtu 3,240.16 lb/hr (SSM venting 3-hr avg.)	FMP & Fuel Type
IN-0180	Midwest Fertilizer Corporation	6/4/14	Back End Flare	4 MMBtu/hr	0.37 lb/MMBtu 804.76 lb/hr (SSM venting 3-hr avg.)	FMP & Fuel Type
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Ammonia Tank Flare**	**1.25 MMBtu/hr**	**0.37 lb/MMBtu, (SSM venting, 168 hr/yr)**	**Work Practice & FMP**
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Emergency Flare**	**0.4 MMBtu/hr**	**0.37 lb/MMBtu, (SSM venting, 168 hr/yr)**	**Work Practice & FMP**
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Small Flare**	**1.25 MMBtu/hr**	**0.37 lb/MMBtu, (SSM venting, 168 hr/yr)**	**Work Practice & FMP**

RBLC Review

Most of the RBLC control method entries for flares list flare work practice requirements and good combustion practices as the principle CO control technologies for flares. The Ohio Valley Resources permit required the use of a flare minimization plan. This plan is intended to find the root cause of excess emissions and to prevent a reoccurrence.

Applicant Proposal

The applicant proposes the following as BACT:

(a) Venting to the ammonia tank flare, small flare, and emergency flare shall not exceed 168 hours each, per 12-consecutive month period.

(b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:

(1) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable; and

(2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other maintenance events.

(c) Flare emissions shall be controlled by use of the following practices:

(1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed five minutes during any two consecutive hours;

(2) Flares shall be operated with a flame present at all times; and

(3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(d) CO emissions from the ammonia tank flare, small flare, and emergency flare shall not exceed 0.37 lb/MMBtu, during normal operation, based on a three-hour average.

Step 5 – Selection of CO BACT for the Ammonia Tank Flare, Small Flare, and Emergency Flare

The Department agrees with the applicant that an emission rate achievable with flare work practice requirements and developing a flare minimization is BACT for the flares. CO emissions from the flares (EUs 11, 22, and 23) shall be controlled through work practices and by minimizing their use, and shall not exceed 0.37 lb/MMBtu during normal operations. CO emissions from the flares venting shall be limited to no more than 168 hours each, per rolling 12-consecutive months.

4.7 CO BACT for the Well Pump and Fire Pump Engine (EUs 65 and 66)

Step 1 – Identification of CO Control Technology for the Pump Engines
Stationary emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60 Subparts IIII and JJJJ, and 40 CFR 63 Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with the applicable emission limitations.

Step 2 – Eliminate Technically Infeasible CO Control Options for the Pump Engines
The only feasible control option for the diesel-fired well pump and gasoline-fired fire pump engines is good combustion practices.

Step 3 – Ranking of the Remaining CO Control Technologies for the Pump Engines

The applicant has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls

The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Diesel-Fired Well Pump and Gasoline-Fired Fire Pump Engines (EUs 65 and 66) – CO						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
SC-0113	Pyramax Ceramics	2/8/12	Fire Pump	500 hp	3.5 g/kW-hr	40 CFR 60, Subpart IIII & Limited Use
ID-0018	Idaho Power Company	6/25/10	Fire Pump Engine	235 kW	None	Tier 3 Engine & GCP
LA-0251	Flopam, Inc.	4/26/11	Two Fire Pump Engines	444 hp	0.65 lb/hr 0.03 tpy	Design & GCP
ID-0017	Southeast Idaho Energy	2/10/09	Emergency Generator, Fire Pump	500 kW	None	GCP & 40 CFR 60 Subpart IIII
IA-0105	Iowa Fertilizer Company	10/26/12	Fire Pump	235 kW	3.5 g/kW-hr (3 stack test avg.) 0.45 tpy	GCP
LA-0254	Entergy Louisiana	8/16/11	Emergency Fire Pump	350 hp	2.6 g/hp-hr	GCP & Fuel Type
IN-0180	Midwest Fertilizer Company	6/4/14	Fire Pump	500 hp	2.6 g/hp-hr (3-hr avg.)	GCP
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Diesel-Fired Well Pump Engine**	**2.7 MMBtu/hr**	0.95 lb/MMBtu	GCP & Limited Use
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Gasoline-Fired Fire Pump Engine**	**2.1 MMBtu/hr**	0.99 lb/MMBtu	Limited Use

RBLC Review

A review of similar units in the RBLC indicates good combustion practices are the principle CO control technology for both diesel-fired and gasoline-fired pump engines.

Applicant Proposal

The applicant proposes the following as BACT:

(a) CO emissions from the operation of the diesel-fired well pump and gasoline-fired fire water pump shall be controlled with limited use of the units.

(b) CO emissions from the diesel-fired well pump shall not exceed 0.95 lb/MMBtu.

(c) CO emissions from the gasoline-fired fire water pump shall not exceed 0.99 lb/MMBtu.

(d) Operating hours for EUs 65 and 66 shall not exceed 168 hours per year, each.

Step 5 – Selection of CO BACT for the Well Pump and Fire Water Pump Engines
The Department agrees with the applicant that an emission rate achievable with limited use is BACT for the pump engines. CO emissions from the diesel-fired well pump engine (EU 65) and the gasoline-fired fire pump engine (EU 66) shall not exceed 0.95 lb/MMBtu and 0.99 lb/MMBtu, respectively, and operating hours will be limited to 168 hours per year each. Compliance with the proposed emission limit will be demonstrated by recording total fuel usage and operating hours for the pump engines.

4.8 CO BACT for the CO2 Vent (EU 14)

Step 1 – Identification of CO Control Technology for the CO_2 Vent
The Department has identified the following control technologies for the CO_2 purification process.

(a) Optimum conversion from CO to CO_2 by use of a catalyst and good operational practices. CO emissions can be minimized by optimum catalytic conversion of CO to CO_2 in the high-end and low-end shift converters.

Step 2 – Eliminate Technically Infeasible CO Control Options for the CO_2 Vent
The only feasible control option for the CO_2 vent is optimum catalytic conversion and good operational practices.

Step 3 – Ranking of the Remaining CO Control Technologies for the CO_2 Vent
The applicant has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA CO_2 Vent (EU 14) – CO						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
LA-0272	Dyno Nobel Louisiana	3/27/13	CO_2 Stripper Vent	115.83 tons/hour	1.49 lb/hr (hourly max) 6.54 tpy	Maximization of the Shift Conversion Efficiency & GCP
ID-0017	Southeast Idaho Energy	2/10/09	Selexol AGR CO_2 Vent	299,585 lb/hr	8.7 lb/hr	Thermal Oxidizer
IA-0105	Iowa Fertilizer Company	10/26/12	CO_2 Regenerator	3,012 metric tons/day	0.02 lb/ton of ammonia (3 stack test avg.) 9.65 tpy	Good Operational Practices
IN-0172	Ohio Valley Resources	9/25/13	CO_2 Purification Process	3,570 tons CO_2/day	0.0117 lb/ton of ammonia (3-hr avg.)	Process Catalyst and Good Operational Procedures
IN-0179	Ohio Valley Resources	9/25/13	CO_2 Purification Process	3,570 tons CO_2/day	0.0117 lb/ton of ammonia (3 stack test avg.)	Process Catalyst and Good Operational Procedures
LA-0236	Donaldson Nitrogen Complex	3/3/09	Four CO_2 Vents	#1 & #2 1,620 tons ammonia/ day (each) #3 & #4 1,785 tons ammonia/ day (each)	#1 – 5.59 lb/hr, #2 – 5.59 lb/hr, #3 – 5.08 lb/hr, #4 – 5.59 lb/hr, 6.55 tpy	Optimum Catalytic Conversion of CO to CO_2
IN-0180	Midwest Fertilizer Company	6/4/14	CO_2 Purification Process	2,400 tons/day ammonia	0.0117 lb/ton of ammonia (3-hr avg.) 100% CO_2 venting	Proper Catalyst Selection
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**CO_2 Vent**	**90 tons/ hour ammonia**	**2.9 lb/hr (hourly max)**	**Optimum Catalytic Conversion of CO to CO_2**

RBLC Review
Entries in the RBLC table above, indicate add-on control devices are not included in the BACT determinations. The entries show BACT as the optimum conversion of CO to CO_2 by proper selection of a production catalyst and good operational practices.

Applicant Proposal
The applicant proposes the following as BACT:

(a) CO emissions from the operation of the CO_2 vent shall be controlled by use of good operational procedures including the selection of an optimal process catalyst.

(b) CO emissions from the CO_2 vent shall not exceed 2.9 lb/hr, based on a three-hour average and 100% venting.

Step 5 – Selection of CO BACT for the CO_2 Vent
The Department agrees with the applicant that an emission rate achievable with good operational practices including the selection of an optimal process catalyst is BACT for the CO_2 vent. CO emissions from the CO_2 vent (EU 14) shall not exceed 2.9 lb/hr.

4.9 CO BACT for the H_2 Vent (EU 19)

Step 1 – Identification of CO Control Technology for the H_2 Vent
The Department has identified the following control technologies for the H_2 vent:

(a) Flaring
Because the waste gases generated during startup and shutdown contain high concentrations of CO, they are suitable for treatment in a flare. Flaring is considered to be a technologically feasible control technology for the H_2 vent.

(b) Limited Use
Because the H_2 vent stack is only utilized to control startup and shutdown events, it is inherently a limited use emission unit.

(c) Catalytic Oxidation
The theory of catalytic oxidation was discussed in detail in the CO BACT for the primary reformer and will not be repeated here. Catalytic oxidation is a technologically feasible control technology for the H_2 Vent.

Step 2 – Eliminate Technically Infeasible CO Control Options for the H_2 Vent
Flaring, catalytic oxidation, and limiting use are all technically feasible options for controlling CO from the H_2 vent. Therefore, none are eliminated.

Step 3 – Ranking of the Remaining CO Control Technologies for the H_2 Vent

(a) Flaring (90% Control)
(b) Catalytic Oxidation (75% Control)
(c) Limited Use (less than 75% Control)

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA H_2 Vent (EU 19) – CO						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
LA-0211	Marathon Petroleum	12/27/06	Hydrogen Plant Hydrogen Vent	5 scf/hr	None	None
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**H_2 Vent**	**15,222 lb CO/startup**	**200 hours/year**	**Limited Use**

RBLC Review
The only entry in the RBLC table above, indicates add-on control devices are not included in the BACT determinations.

Applicant Proposal
The applicant provided an economic analysis for the installation of catalytic oxidation on the H_2 vent to demonstrate that the use of a catalytic oxidizer is not economically feasible on this unit. A summary of the analysis is shown below:

Control Alternative	Captured Emissions (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Operating Costs ($/year)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	126.9	125.6	$8,592,600	$398,714	$1,622,300	$12,916
Capital Recovery Factor = 0.1424 (7% for a 10 year life cycle)						

The economic analysis indicates the level of CO reduction does not justify the use of catalytic oxidation on the H_2 vent. Based on the excessive cost per ton of CO removed per year, installing catalytic oxidation on the H_2 vent is not considered a feasible option for reducing CO emissions.

The applicant proposes the following as BACT:

(a) Venting to the H_2 vent shall be limited to no more than 200 hours per 12-consecutive month period.

(b) CO emissions from the operation of the H_2 vent shall not exceed 15,222 lb CO/startup.

Step 5 – Selection of CO BACT for the H_2 Vent
The Department agrees with the applicant that an emission rate achievable by limiting the H_2 vent to no more than 200 hours per year is BACT for the H_2 vent.

5.0 BACT Determination for VOC
The KNO facility has five existing 37.6 MMBtu/hr Solar Centaur GSC-4000 turbines that burn natural gas, one 1,350 MMBtu/hr primary reformer, heaters, boilers, flares, and several other EUs subject to BACT. The Department reviewed the control technologies Agrium identified in their application and determined VOC BACT for the EUs listed in Table B-3.

The Department based its assessment on BACT determinations found in the RBLC and internet research. Table B-4 summarizes VOC BACT determinations in the RBLC for the proposed EUs.

Table B-3: VOC BACT Determinations in RBLC for January 2004-August 8, 2014

Description of NOx BACT	Primary Reformer	Startup Heater	Boilers	Flares	Well and Fire Pump	CO2 Vent	MDEA Storage Tanks	Urea Granulation Line
Good Combustion Practices	2	2	2	4	3			2
Good Operating Practices	1	1	1	2		2		
Nitrogen Gas Blanket							3	
Packed Bed Scrubber							1	
Oxidation Catalyst						1		
Wet Scrubber								2
Total	**3**	**3**	**3**	**6**	**3**	**3**	**4**	**4**

5.1 VOC BACT for the Turbines (EUs 55 through 59)

Step 1- Identification of VOC Control Technology for the Turbines
From research, the Department identified the following technologies as available for VOC control of turbines rated at 25 MW or less:

(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 reduction of 85% to 90%. The use of an oxidation catalyst is a feasible control technology for the combustion 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 the gas combustion turbines.

Step 2 - Elimination of Technically Infeasible VOC Control Options for Turbines
As explained in Section 5.1, catalytic oxidation and good combustion practices are technically feasible options to control VOC emissions from turbines smaller than 25 MW.

Step 3 - Ranking of Remaining VOC Control Technologies for Turbines
The following control technologies have been identified and ranked for control of VOC from the turbines.

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

Step 4 - Evaluate the Most Effective Controls

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units (combustion turbines rated at less than 25 MW). All data in this table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA
Solar Combustion Turbines (EUs 55 through 59) – VOC

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
CA-1096	Vernon City Light and Power	5/27/03	Combined Cycle Combustion Turbine	43 MW Combined Cycle Turbine	2 ppm_{vd} @ 15% O_2 (1-hr avg.)	Oxidation Catalyst & SCR
DE-0023	NRG Energy Center Dover	10/31/12	Combined Cycle Combustion Turbine	655 MMBtu/hr	6.4 lb/hr (1-hr avg.)	Oxidation Catalyst
LA-0194	Sabine Pass LNG Terminal	9/3/09	Four Gas Turbine Generators	30 MW, 290 MMBtu/hr (each)	1.2 lb/hr (maximum) 4.84 tpy (maximum)	GCP & Fuel Type
PA-0289	Geisinger Medical Center	6/18/10	Gas Turbine	55.62 MMBtu/hr	0.6 lb/hr (in SoLoNOx mode) 11.9 lb/hr (sub-zero non-SoLoNOx mode)	None
TX-0497	Ineos Chocolate Bayou Facility	8/29/06	Two Gas Turbines with HRSG	35 MW (each)	6.14 lb/hr 40.88 tpy	GCP
TX-0548	Madison Bell Energy Center	8/18/09	Four Combined Cycle Combustion Turbines	75 MW each	2 ppm_{vd} @ 15% O_2 (1-hr avg.)	GCP
WY-0067	Echo Springs Gas Plant	4/1/09	Gas Turbine	12,555 hp	25 ppm_{vd} 3 tpy	GCP
WY-0067	Echo Springs Gas Plant	4/1/09	Gas Turbine	16,162 hp	25 ppm_{vd} 3.7 tpy	GCP
WY-0067	Echo Springs Gas Plant	4/1/09	Gas Turbine	3,856 hp	50 ppm_{vd} 1.1 tpy	GCP
WY-0070	Black Hills Power, Inc.	8/27/12	Combined Cycle Combustion Turbine	40 MW	3 ppm_{vd} @ 15% O_2 (1-hr avg.) 3 lb/hr (3-hr avg.) 14.7 tpy	Oxidation Catalyst
IN-0180	Midwest Fertilizer Corporation	6/4/14	Two Gas Turbine	283 MMBtu/hr (each)	2.5 ppm_{vd} at 15% O_2 (1-hr avg.)	GCP & Design
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Five Gas Combustion Turbines**	**37.6 MMBtu/hr (each)**	0.0021 lb/MMBtu (1-hr avg.)	None

RBLC Review

VOC control methods listed in the RBLC include good combustion practices and the use of an oxidation catalyst. Existing RBLC entries indicate VOC emission rates range from a low of 2 ppm_{vd} to well over 8 ppm_{vd}.

Applicant Proposal
The applicant provided an economic analysis of the installation of catalytic oxidation on the turbines to demonstrate that the use of catalytic oxidation is not economically feasible on these units. A summary of the analysis is shown below:

Control Alternative	Captured Emissions (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Operating Costs ($/year)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	1.75	1.4	$1,386,700	$277,600	$408,504	$291,788
Capital Recovery Factor = 0.0944 (7% for a 20 year life cycle)						

The economic analysis indicates the level of VOC reduction does not justify the use of catalytic oxidation. Based on the excessive cost per ton of VOC removed per year, installing catalytic oxidation on the turbines is not considered a feasible option for reducing VOC emissions.

The applicant proposes the following as BACT:

(a) VOC emissions from the turbines at the waste heat boiler outlet shall not exceed 0.0021 lb/MMBtu.

Step 5 – Selection of VOC BACT for Turbines
The Department agrees with the applicant that an emission rate achievable with no controls is BACT for the turbines. VOC emissions from each of the natural gas fired combustion turbines (EUs 55 through 59) shall not exceed 0.0021 lb/MMBtu.

5.2 VOC BACT for the Primary Reformer (EU 12)

Step 1 – Identification of VOC Control Technology for the Primary Reformer
From research, the Department identified the following technologies as available for VOC control of reformer furnaces:

(a) Thermal Oxidizers
The thermal oxidizer has a stabilized flame maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors and is considered a technology for controlling VOC emissions. Upon passing through the flame, the gas containing VOC is heated from its inlet temperature to its ignition temperature (It is the temperature at which the combustion reaction rate (and consequently the energy production rate) exceeds the rate of heat losses, thereby raising the temperature of the gases to some higher value). Thus, any VOC/air mixture will ignite if its temperature is raised to a sufficiently high level. The VOC-containing mixture ignites at some temperature between the preheat temperature and the reaction temperature. The ignition occurs at some point during the heating of a waste stream. The mixture continues to react as it flows through the combustion chamber.

Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 °F to 2,000 °F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the level of control. Regenerative Thermal Oxidizers consists of direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.

The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed) to its ignition temperature. The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it to the combustion chamber outlet temperature. The process flows are then switched, feeding the inlet stream to the hot bed. This cyclic process affords high energy recovery (up to 95%). It is impractical for thermal oxidizers to reduce emissions of VOC from a properly operated natural gas combustion units. This is due to the large energy input required to obtain the required destruction temperature because the exhaust stream lacks adequate fuel. The use of a thermal oxidizer is not a technically feasible control option for the reformer furnace.

(b) Catalytic Oxidizers
Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors and is considered a technology for controlling VOC emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures (compared to thermal oxidation) without the catalyst undergoing change itself. Catalytic oxidizers operate at 650°F to 1000°F and require approximately 1.5 to 2.0 ft^3 of catalyst per 1,000 standard ft^3 gas flow.

Emissions from some emission units may contain significant amount of particulates. These particulates can poison the catalyst resulting in the failure of catalytic oxidation. For some fuels, such as coal and residual oil, contaminants would likely be present in such concentrations so as to foul catalysts quickly thereby making such systems infeasible due to the need to constantly replace catalyst materials. In addition, the use of oxidation catalysts on units with high sulfur fuels can also result in the creation of sulfuric acid mist through the conversion of SO_2 to SO_3 and subsequent combination with moisture in the exhaust gas. The use of an oxidation catalyst to control VOC emissions is feasible for gas fired units because the fuel is a low sulfur fuel with relatively low concentrations of other contaminants, such as metals. Due to the lower operating temperature requirements, it is possible to use catalytic oxidizers on reformer exhaust gases. While it is physically feasible to use catalytic oxidation, it is not normally used to control VOC emissions from natural gas combustion due to excessive costs associated with raising the temperature of a low heating value gas. The use of a catalytic oxidizer is not a technically feasible control option for the primary reformer.

(c) Flare
The low heating value of the reformer furnace exhaust is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of a flare for this stream would be the creation of additional emissions from burning supplemental fuel, including VOC. The use of a flare is not a technically infeasible option for the reformer furnace.

(d) Combustion Control
This type of control is appropriate for any type of fuel combustion source. Combustion process controls involve combustion chamber designs and operating practices that improve the oxidation process and minimize incomplete combustion. Factors affecting VOC emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics. Combustion control is a technically feasible control option for the reformer furnace.

Step 2 – Eliminate Technically Infeasible VOC Control Options for the Primary Reformer
As explained in Section 5.2, thermal oxidizers, catalytic oxidizers, and flaring are not feasible control technologies to reduce VOC emissions from the reformer furnace.

Step 3 – Ranking of the Remaining VOC Control Technologies for the Primary Reformer
The Department has identified a single control technology for VOC control from the reformer. Therefore, no ranking is necessary.

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Primary Reformer (EU 12) – VOC						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
TX-0657	Beaumont Gas to Gasoline Plant	5/16/14	Primary Reformer	1,552 MMBtu/hr	5 ppm (annual) 10.16 tpy	GCP
LA-0272	Dyno Nobel Louisiana Ammonia	3/27/13	Primary Reformer	956.2 MMBtu/hr	6.19 lb/hr (hourly maximum) 22.58 tpy	GCP & Design
IA-0105	Iowa Fertilizer Company	10/26/12	Syngas Primary Reformer	1,152.6 MMBtu/hr	0.0014 lb/MMBtu (3 stack test avg.) 6.95 tpy	GCP
IA-0106	CF Industries Nitrogen, LLC	7/12/13	Primary Reformer	1062.6 MMBtu/hr	0.0014 lb/MMBtu (3 stack test avg.) 6.52 tpy	GCP & Fuel Type
IN-0172	Ohio Valley Resources	9/25/13	Methane Primary Reformer	1,006.4 MMBtu/hr	5.51 lb/MMcf (3-hr avg.)	GCP

OK-0134	Pryor Plant Chemical Company	2/23/09	Primary Reformer	700 ton ammonia per day	1.21 lb/hr	None
LA-0211	Garyville Refinery	12/27/06	Hydrogen Reformer	1,412.5 MMBtu/hr	0.0015 lb/MMBtu (3-hr avg.)	Design, Operation, & Good Engineering Practices
NM-0050	Artesia Refinery	12/14/07	Methane Reformer Heater	337 MMBtu/hr	0.005 lb/MMBtu 1.69 lb/hr	Fuel Type
IN-0180	Midwest Fertilizer Corporation	6/4/14	Reformer Furnace	950.64 MMBtu/hr	5.5 lb/MMcf (3-hr avg.)	GCP & Design
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Primary Reformer**	**1,350 MMBtu/hr**	**0.0054 lb/MMBtu (3-hr avg.)**	**None**

RBLC Review
A review of the RBLC control method entries for reformer furnaces indicates add-on controls are not typical for this type of emission unit. The entries indicate that proper design and good combustion practices are employed to ensure complete combustion. While the Garyville Refinery has a BACT limit lower than the applicant proposed, it uses a hydrogen rich fuel which is a different technology from the methane fuel used at the Midwest Fertilizer Corporation, Ohio Valley Resources, and the Iowa Fertilizer Company.

Applicant Proposal
The applicant proposes the following as BACT:

(a) VOC emissions from the primary reformer shall not exceed 5.5 lb/MMcf (0.0054 lb/MMBtu).

The applicant's proposal is consistent with the majority of entries in the RBLC for VOCs. These emission limits are based on the uncontrolled emission factors found in AP-42. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0014 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. The Department believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

(a) Add-on emission controls have been demonstrated to be infeasible or not cost-effective.

(b) The majority of entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.

(c) The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT.

(1) Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.

(2) IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

The Department believes VOC BACT for natural gas-fired combustion in the reformer furnace is 5.5 lb/MMcf with the use of natural gas/process off gases.

Step 5 – Selection of VOC BACT for the Primary Reformer
The Department agrees with the applicant that an emission rate achievable with no controls is BACT for the primary reformer. VOC emissions from the primary reformer (EU 12) shall not exceed 5.5 lb/MMcf (0.0054 lb/MMBtu). Initial compliance with the proposed emission limit will be demonstrated by conducting a stack test.

5.3 VOC BACT for the Package Boilers (EUs 44, 48, and 49)

Step 1 – Identification of VOC Control Technology for the Package Boilers
From research, the Department identified the following technologies as available for VOC control for package boilers:

(a) Thermal Oxidation
This control technology is typically used to control organic vapors. It is most effective in controlling emissions with high organic loading. The organic containing gas stream is mixed with additional fuel to oxidize the organic components to carbon dioxide and water vapor. The additional thermal energy forces a more complete oxidation of the fuel resulting in lower VOC levels and higher carbon dioxide emission levels. Catalytic Oxidation is not normally used on natural gas combustion products because of their low heating value. Significant supplemental fuel will be required to heat the exhaust gas to the required operating temperature to achieve destruction. The boiler exhaust gas is at 350 °F and would require heating to at least 1,500 °F to achieve any reduction. In practice, thermal oxidation has not been installed on natural gas combustion sources. Thermal oxidation is not a feasible control technology for the package boilers.

The theory of thermal oxidizers was discussed in detail in the VOC BACT for the primary reformer and will not be repeated here. The use of a regenerative thermal oxidizer is not a technically feasible control option for the package boilers because the exhaust stream is comprised of natural gas combustion products with extremely low heating value. Thermal oxidizers have not been installed on natural gas combustion sources to control VOC.

(b) Catalytic Oxidation

Catalytic oxidation is a process similar to thermal oxidation. Catalytic oxidation uses a catalyst to allow the oxidation process to occur at a lower temperature. The exhaust gas would only be heated to 600 °F to 800 °F. VOC in the exhaust gas is combined with additional oxygen to form carbon dioxide and water vapor. As with thermal oxidation, it is not traditionally installed on natural gas combustion sources because of the low heating value of the exhaust gas. The combustion of additional fuel to raise the stack gas temperature will result in an increase in other regulated pollutants. Catalytic oxidation is not a feasible control technology for the package boilers.

(c) Flares

Flares are another form of thermal oxidation. The VOC containing exhaust gas is combined with additional fuel to raise the exhaust gas temperature to a level where it is converted to carbon dioxide and water vapor. As with the thermal oxidizer, flares are not typically installed on natural gas combustion sources to achieve a reduction in volatile organic compounds. The combustion of additional fuel to raise the temperature of the exhaust gas to at least 600 °F will result in an increase in other regulated pollutants. VOC control by flare is not a feasible control option for the package boilers.

(d) Good Combustion Practices

The theory of good combustion practices was discussed in detail in the NOx BACT for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of VOC. Therefore good combustion practices is a feasible control option for the package boilers.

Step 2 – Eliminate Technically Infeasible VOC Control Options for the Package Boilers

As explained in Section 5.3, thermal oxidation, catalytic oxidation, and flaring are technically infeasible for controlling VOC emissions from the package boilers.

Step 3 – Ranking of the Remaining VOC Control Technologies for the Package Boilers

The applicant has proposed the only feasible control technology for the package boilers. Therefore, a ranking is not necessary.

Step 4 – Evaluate the Most Effective Controls

The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Package Boilers (EUs 44, 48, and 49) – VOC						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
AR-0094	John W. Turk Jr. Power Plant	11/5/08	Auxiliary Boiler	555 MMBtu/hr	0.0055 lb/MMBtu (3-hr avg.)	None
IA-0105	Iowa Fertilizer Company	10/26/12	Auxiliary Boiler	472.4 MMBtu/hr	0.0014 lb/MMBtu (3 stack test avg.), 0.62 tpy	GCP
IN-0172	Ohio Valley Resources	9/25/13	Four Natural Gas-Fired Boilers	218 MMBtu/hr (each)	5.5 lb/MMcf (3-hr avg.)	GCP & Design
LA-0272	Dyno Nobel Louisiana Ammonia	3/27/13	Commissioning Boilers	217.5 MMBtu/hr	1.41 lb/hr (hourly maximum), 2.58 tpy, 0.0054 lb/MMBtu (annual average)	GCP & Design
NJ-0043	Liberty Generating Station	3/28/02	Auxiliary Natural Gas Boiler	200 MMBtu/hr	50 ppm_{vd} @ 7% O_2, 1.6 lb/hr, 0.008 lb/MMBtu	CO Catalyst
OH-0310	American Municipal Power	10/8/9	Auxiliary Boiler	150 MMBtu/hr	0.83 lb/hr, 0.36 tpy, 5.5 lb/MMcf	None
OK-0135	Pryor Plant Chemical Company	2/23/09	Boilers 1 & 2	80 MMBtu/hr	0.5 lb/hr	GCP
TX-0386	Amella Energy Center	3/26/02	Auxiliary Natural Gas Boiler	155 MMBtu/hr	3.1 lb/hr (maximum)	None
TX-0641	Pinecrest Energy Center	11/12/13	Auxiliary Boiler	150 MMBtu/hr	0.9 lb/hr	GCP & Fuel Type
IN-0180	Midwest Fertilizer Corporation	6/4/14	Three Auxiliary Boiler	218.6 MMBtu/hr (each)	5.5 lb/MMcf (3-hr avg.), 1501.91 MMcf/yr	GCP & Design
WV-0023	Longview Power, LLC	3/2/04	Auxiliary Natural Gas Boiler	225 MMBtu/hr	0.0054 lb/MMBtu (3-hr rolling), 3,000 hr/yr	GCP & Fuel Type
WY-0074	Green River Soda Ash Plant	11/18/13	Natural Gas Package Boiler	254 MMBtu/hr	0.0054 lb/MMBtu (3-hr avg.) 1.4 lb/hr (3-hr avg.)	GCP
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Package Boilers**	**243 MMBtu/hr**	**0.0054 lb/MMBtu (3-hr avg.)**	**None**

RBLC Review

A review of similar units in the RBLC indicates add-on controls are not typically used on natural gas-fired boilers. VOC emissions are exclusively controlled by good combustion practices and the use of a low carbon fuel, natural gas. The lowest emission rate listed in RBLC is for the Iowa Fertilizer Corporation (IFC) with the use of good combustion practices.

Applicant Proposal
The applicant provided an economic analysis of the installation of catalytic oxidation on the boilers to demonstrate that the use of catalytic oxidation is not economically feasible on these units. A summary of the analysis is shown below:

Control Alternative	Captured Emissions (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Operating Costs ($/year)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	17.22	13.78	$9,763,100	$1,093,700	$2,015,336	$143,952
Capital Recovery Factor = 0.0944 (7% for a 20 year life cycle)						

The economic analysis indicates the level of VOC reduction does not justify the use of catalytic oxidation. Based on the excessive cost per ton of VOC removed per year, installing catalytic oxidation on the package boilers is not considered a feasible option for reducing VOC emissions.

The applicant proposes the following as BACT:

(a) VOC emissions from the package boilers shall not exceed 0.0054 lb/MMBtu, based on a 3-hr average.

(b) Compliance with the proposed emission limit will be demonstrated by conducting an initial stack test to obtain an emission rate.

Step 5 – Selection of VOC BACT for the Package Boilers
The Department agrees with the applicant that an emission rate achievable with no controls is BACT for the package boilers. VOC emissions from the package boilers (EUs 44, 48, and 49) shall not exceed 0.0054 lb/MMBtu. Initial compliance with the proposed emission limit will be demonstrated by conducting an initial stack test.

5.4 VOC BACT for the Waste Heat Boilers (EUs 50 through 54)

Step 1 – Identification of VOC Control Technology for the Waste Heat Boilers
From research, the Department identified the following technologies as available for VOC control for five waste heat boilers:

(a) Thermal Oxidizers
The theory behind thermal oxidizers was discussed in detail in the VOC BACT for the package boilers and will not be repeated here. The use of a regenerative thermal oxidizer is not a technically feasible control option for the waste heat boilers because the exhaust stream is comprised of natural gas combustion products with extremely low heating value. Thermal oxidizers have not been installed on natural gas combustion sources to control VOC.

(b) Catalytic Oxidizers
The theory behind catalytic oxidizers was discussed in detail in the VOC BACT for the package boilers and will not be repeated here. The use of an oxidation catalyst to control carbon monoxide emissions is feasible for gas fired units because the fuel is a low sulfur fuel with relatively low concentrations of other contaminants, such as metals. However the use of a catalytic oxidizer is not a technically feasible control option for the waste heat boilers due to the high level of excess air from the combustion turbines.

(c) Flare
The theory behind flaring was discussed in detail in the VOC BACT for the package boilers and will not be repeated here. While technologically feasible, it is not a technically feasible control option for the waste heat boilers.

(d) Good Combustion Practices
The theory of good combustion practices was discussed in detail in the NOx BACT for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of VOC. Therefore good combustion practices is a feasible control option for the waste heat boilers.

Step 2 – Eliminate Technically Infeasible VOC Control Options for the Waste Heat Boilers
As explained in Section 5.4, thermal oxidizers, catalytic oxidizers, and flares are technically infeasible VOC control options for use on waste heat boilers.

Step 3 – Ranking of the Remaining VOC Control Technologies for the Waste Heat boilers
The applicant has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA **Waste Heat Boilers (EUs 50 through 54) – VOC**						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
AR-0094	John W. Turk Jr. Power Plant	11/5/08	Auxiliary Boiler	555 MMBtu/hr	0.0055 lb/MMBtu (3-hr avg.)	None
IA-0105	Iowa Fertilizer Company	10/26/12	Auxiliary Boiler	472.4 MMBtu/hr	0.0014 lb/MMBtu (3 stack test avg.), 0.62 tpy	GCP
IN-0172	Ohio Valley Resources	9/25/13	Four Natural Gas-Fired Boilers	218 MMBtu/hr (each)	5.5 lb/MMcf (3-hr avg.)	GCP & Design

LA-0272	Dyno Nobel Louisiana Ammonia	3/27/13	Commissioning Boilers	217.5 MMBtu/hr	1.41 lb/hr (hourly maximum), 2.58 tpy, 0.0054 lb/MMBtu (annual average)	GCP & Design
NJ-0043	Liberty Generating Station	3/28/02	Auxiliary Natural Gas Boiler	200 MMBtu/hr	50 ppm_{vd} @ 7% O_2, 1.6 lb/hr, 0.008 lb/MMBtu	CO Catalyst
OH-0310	American Municipal Power	10/8/9	Auxiliary Boiler	150 MMBtu/hr	0.83 lb/hr, 0.36 tpy, 5.5 lb/MMcf	None
OK-0135	Pryor Plant Chemical Company	2/23/09	Boilers 1 & 2	80 MMBtu/hr	0.5 lb/hr	GCP
TX-0386	Amella Energy Center	3/26/02	Auxiliary Natural Gas Boiler	155 MMBtu/hr	3.1 lb/hr (maximum)	None
TX-0641	Pinecrest Energy Center	11/12/13	Auxiliary Boiler	150 MMBtu/hr	0.9 lb/hr	GCP & Fuel Type
IN-0180	Midwest Fertilizer Corporation	6/4/14	Three Auxiliary Boiler	218.6 MMBtu/hr (each)	5.5 lb/MMcf (3-hr avg.), 1501.91 MMcf/yr	GCP & Design
WV-0023	Longview Power, LLC	3/2/04	Auxiliary Natural Gas Boiler	225 MMBtu/hr	0.0054 lb/MMBtu (3-hr rolling) 3,000 hr/yr	GCP & Fuel Type
WY-0074	Green River Soda Ash Plant	11/18/13	Natural Gas Package Boiler	254 MMBtu/hr	0.0054 lb/MMBtu (3-hr avg.), 1.4 lb/hr (3-hr avg.)	GCP
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Waste Heat Boilers**	**50 MMBtu/hr (each)**	**0.0054 lb/MMBtu (3-hr avg.)**	**None**

RBLC Review
A review of similar units in the RBLC indicates add-on controls are not typically used on natural gas fired boilers. VOC emissions are exclusively controlled by good combustion practices and the use of a low carbon fuel, natural gas. The lowest emission rate listed in RBLC is for the Iowa Fertilizer Corporation (IFC) with the use of good combustion practices.

Applicant Proposal
The applicant proposes the following as BACT:

(a) VOC emissions from the package boilers shall not exceed 0.0054 lb/MMBtu, based on a 3-hr average.

Step 5 – Selection of VOC BACT for the Waste Heat Boilers
The Department agrees with the applicant that an emission rate achievable with no controls is BACT for the waste heat boilers. VOC emissions from the boilers (EUs 50 through 54) shall not exceed 0.0054 lb/MMBtu. Initial compliance with the proposed emission limit will be demonstrated by conducting an initial stack test.

5.5 VOC BACT for the Startup Heater (EU 13)

Step 1 – Identification of VOC Control Technology for the Startup Heater
From research, the Department identified the following technologies as available for VOC control of startup heaters: thermal oxidizers, catalytic oxidizers, and good combustion practices.

(a) Thermal Oxidizers
The theory of thermal oxidizers was discussed in detail in the CO BACT for the primary reformer and will not be repeated here. Generally, it is impractical for thermal oxidizers to reduce VOC emissions from a properly operated natural gas-fired combustion unit. This is due to the large energy input required to obtain the required destruction temperature because the exhaust stream lacks adequate fuel. The use of a thermal oxidizer is not a feasible control technology for the startup heater.

(b) Catalytic Oxidizers
The theory of catalytic oxidizers was discussed in detail in the CO BACT for the primary reformer and will not be repeated here. Much like the thermal oxidizer, a catalytic oxidizer uses high temperatures in the presence of a catalyst to combust VOC in the exhaust stream. This works for exhaust steams with significant organic content. The exhaust stream from the startup heater does not contain sufficient organic material to support combustion, and a large amount of additional combustion fuel is required. The use of a catalytic oxidizer is not a technologically feasible control option for the startup heater.

(c) Flares
The theory of operation of flares was discussed in detail under the CO BACT for the primary reformer and will not be repeated here. The low heating value of the startup heater exhaust is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of a flare for this stream would be the creation of additional emissions from burning supplemental fuel, including VOC. The VOC emissions created by this unit are due to natural gas combustion, additional natural gas would increase VOC emissions. The use of a flare is not a technically infeasible option for the startup heater

(d) Good Combustion Practices
The theory of good combustion practices was discussed in detail in the NOx BACT for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of VOC. Therefore good combustion practices is a feasible control option for the startup heater.

Step 2 – Eliminate Technically Infeasible VOC Control Options for the Startup Heater
As explained in Section 5.5, thermal oxidizers, catalytic oxidizers, and flares are not feasible control technologies to reduce VOC emissions from the startup heater

Step 3 – Ranking of the Remaining VOC Control Technologies for the Startup Heater
The only conventional VOC control technology that is technologically feasible for the startup heater is good combustion practices. A ranking is not necessary.

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Startup Heater (EU 13) – VOC						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
TX-0657	Beaumont Gas to Gasoline Plant	5/16/14	Heater	45 MMBtu/hr	0.59 tpy	GCP
LA-0272	Dyno Nobel Louisiana Ammonia	3/27/13	Ammonia Startup Heater	61 MMBtu/hr	0.38 lb/hr (max), 0.08 tpy, 500 hours/yr	GCP & Design
OH-0329	BP Products Husky Refining	8/7/09	Reformer Heater	519 MMBtu/hr	2.8 lb/hr, 12.28 tpy, 5.5 lb/MMcf	None
IA-0105	Iowa Fertilizer Company	10/26/12	Startup Heater	110 MMBtu/hr	0.0014 lb/MMBtu, 0.01 tpy	GCP
IN-0172	Ohio Valley Resources	9/25/13	Ammonia Catalyst Startup Heater	106.3 MMBtu/hr	5.5 lb/MMcf (3-hr avg.), 20.84 MMcf/year	GCP & Fuel Type
IN-0180	Midwest Fertilizer Corporation	6/4/14	Startup Heater	92.5 MMBtu/hr	5.5 lb/MMcf (3-hr avg.)	GCP, Design, & Fuel Type
MD-0035	Dominion Cove Pt.	8/12/05	Vaporization Heater	88.4 MMBtu/hr	0.002 lb/MMBtu	Catalytic Oxidation & Fuel Type
MN-0070	Minnesota Steel Industries	9/7/07	Process Heaters	606 MMBtu/hr	0.08 lb/MMBtu, 50 lb/hr (1 hour rolling avg.)	None
OK-0134	Pryor Plant Chemical Company	2/23/09	Nitric Acid Preheaters	20 MMBtu/hr	0.11 lb/hr	GCP
SC-0115	GP Clarendon LP	2/10/09	Backup Oil Heater	75 MMBtu/hr	0.39 lb/hr, 1.72 tpy	GCP
WY-0067	Williams Field Services	4/1/09	Hot Oil Heater	84 MMBtu/hr	0.02 lb/MMBtu, 7 tpy	GCP
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Startup Heater**	**101 MMBtu/hr**	**0.0054 lb/MMBtu, 200 hours/year**	**Limited Use**

RBLC Review
A review of similar units in the RBLC indicates add-on control technology is not practical for natural gas-fired process heaters. VOC emissions are controlled exclusively by good combustion practices and limits on the operation of the combustion unit. As discussed in the VOC BACT for the primary reformer, catalytic oxidation is not a cost effective control technology for the primary reformer. Because of the lower utilization of the startup heater and lower VOC emissions, it is even less cost effective for the startup heater.

Applicant Proposal
The applicant proposes the following as BACT:

(a) VOC emissions from the operation of the startup heater shall be controlled with limited use of the unit.

(b) VOC emissions from the startup heater shall not exceed 0.0054 lb/MMBtu.

(c) Operating hours for the startup heater shall not exceed 200 hours per year.

The applicant's proposal is consistent with a majority of the entries in the RBLC for VOC emissions. The applicant's proposed emission limits are based on the uncontrolled emission factors found in AP-42. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0014 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. The Department believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

(a) Add-on emission controls have been demonstrated to be infeasible or not cost-effective.

(b) The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.

(c) The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT.

    (1) Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.

    (2) IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

Step 5 – Selection of VOC BACT for the Startup Heater
The Department agrees with the applicant that an emission rate achievable with limited use is BACT for the startup heater. VOC emissions from the startup heater (EU 13) shall not exceed 0.0054 lb/MMscf and operating hours will be limited to 200 hours per year. Compliance with the proposed emission limit will be demonstrated by recording total fuel usage and operating hours for the startup heater.

5.6 VOC BACT for the Ammonia Tank Flare and Small Flares (EUs 11, 22, and 23)

Step 1 – Identification of VOC Control Technology for the Flares
From research, the Department identified the following technologies as available for VOC control of the flares: flare work practice requirements, process flaring minimization plan (FMP); and flare gas recovery.

(a) Flare Work Practice Requirements
Flare work practice requirements can be found in 40 CFR 60.18 (c) and (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 use of proper flare design and good combustion practices are technically feasible control options for the flares.

(b) Process Flaring Minimization Plan
Process flaring minimization plans define the procedures intended to reduce the volume of gas going to the flare without compromising plant operations and safety. Process flaring minimization practices is a technically feasible control option 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 for the KNO facility is not technically feasible because the gases controlled by the flares contain ammonia and are not suitable for use in other operations or as fuel at the plant.

Step 2 – Eliminate Technically Infeasible VOC Control Options for the Flares
As explained in Section 5.6, flare gas recovery is not feasible to control VOC emissions from the flares.

Step 3 – Ranking of the Remaining VOC Control Technologies for the Flares
The following control technologies have been identified and ranked for the control of VOC from the flares.

(a) Flare Work Practice Requirements
(b) Process Flaring Minimization Plan

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Ammonia Tank Flare, Plants 4 and 5 Small and Emergency Flares (EUs 11, 22, and 23) – VOC						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
LA-0272	Dyno Nobel Louisiana Ammonia	3/27/13	Ammonia Storage Flare	0.25 MMBtu/hr pilot, 14.94 MMBtu/hr vent gas	0.003 lb/hr (hourly maximum) 0.01 tpy (annual maximum)	Work Practice & GCP
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Work Practice & GCP
IN-0172	Ohio Valley Resources	9/25/13	Ammonia Storage Flare	0.13 MMBtu/hr	0.0054 lb/MMBtu, (SSM venting, 168 hr/yr)	FMP & Fuel Type
IA-0089	Homeland Energy Solutions	8/8/07	Startup and Shutdown Flares	25 MMBtu	0.006 lb/MMBtu	None
IN-0180	Midwest Fertilizer Corporation	6/4/14	Ammonia Storage Flare	1.5 MMBtu/hr	0.0054 lb/MMBtu (3-hr avg.) (SSM venting, 168 hr/yr)	FMP & Fuel Type
IN-0180	Midwest Fertilizer Corporation	6/4/14	Front End Flare	4 MMBtu/hr	0.0054 lb/MMBtu 47.26 lb/hr (SSM venting 3-hr avg.)	FMP & Fuel Type
IN-0180	Midwest Fertilizer Corporation	6/4/14	Back End Flare	4 MMBtu/hr	0.0054 lb/MMBtu 11.73 lb/hr (SSM venting 3-hr avg.)	FMP & Fuel Type
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Ammonia Tank Flare**	**1.25 MMBtu/hr**	**0.0054 lb/MMBtu, (SSM venting, 168 hr/yr)**	**Work Practice & FMP**
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Emergency Flare**	**0.4 MMBtu/hr**	**0.0054 lb/MMBtu, (SSM venting, 168 hr/yr)**	**Work Practice & FMP**
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Small Flare**	**1.25 MMBtu/hr**	**0.0054 lb/MMBtu, (SSM venting, 168 hr/yr)**	**Work Practice & FMP**

RBLC Review
Most of the RBLC control method entries for flares list flare work practice requirements and good combustion practices as the principle VOC control technologies for flares. The Ohio Valley Resources permit required the use of a flare minimization plan. This plan is intended to find the root cause of excess emissions and to prevent a reoccurrence.

Applicant Proposal
The applicant proposes the following as BACT:

(a) Venting to the ammonia tank flare, small flare, and emergency flare shall not exceed 168 hours each, per 12-consecutive month period.

(b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:

  (1) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable; and

  (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other maintenance events.

(c) Flare emissions shall be controlled by use of the following practices:

  (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed five minutes during any two consecutive hours;

  (2) Flares shall be operated with a flame present at all times; and

  (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(d) VOC emissions from the ammonia tank flare, small flare, and emergency flare shall not exceed 0.0054 lb/MMBtu, during normal operation, based on a three-hour average.

Step 5 – Selection of VOC BACT for the Ammonia Tank Flare, Small Flare, and Emergency Flare

The Department agrees with the applicant that an emission rate achievable with flare work practice requirements and developing a flare minimization is BACT for the flares. VOC emissions from the flares (EUs 11, 22, and 23) shall be controlled through work practices and by minimizing their use, and shall not exceed 0.0054 lb/MMBtu during normal operations. VOC emissions from the flares venting shall be limited to no more than 168 hours each, per rolling 12-consecutive months.

5.7 VOC BACT for the Well Pump and Fire Pump Engine (EUs 65 and 66)

Step 1 – Identification of VOC Control Technology for the Pump Engines
Stationary emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60 Subparts IIII and JJJJ, and 40 CFR 63 Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with the applicable emission limitations.

Step 2 – Eliminate Technically Infeasible VOC Control Options for the Pump Engines
The only feasible control option for the diesel-fired well pump and gasoline-fired fire pump engines is good combustion practices.

Step 3 – Ranking of the Remaining VOC Control Technologies for the Pump Engines
The applicant has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Diesel-Fired Well Pump and Gasoline-Fired Fire Pump Engines (EUs 65 and 66) – VOC						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
SC-0113	Pyramax Ceramics	2/8/12	Fire Pump	500 hp	4.0 g/kW-hr 100 hr/yr	40 CFR 60, Subpart IIII & Limited Use
ID-0018	Idaho Power Company	6/25/10	Fire Pump Engine	235 kW	4.0 g/kW-hr	Tier 3 Engine & GCP
IN-0172	Ohio Valley Resources	9/25/13	Diesel-Fired Emergency Water Pump	481 hp	0.141 g/hp-hr (3-hr avg.)	GCP
OK-0129	Associated Electric Cooperative	1/23/09	Fire Pump	267 hp	0.66 lb/hr	GCP
IA-0105	Iowa Fertilizer Company	10/26/12	Fire Pump	235 kW	0.25 g/kW-hr (3 stack test avg.) 0.03 tpy	GCP
LA-0254	Entergy Louisiana	8/16/11	Emergency Fire Pump	350 hp	1.0 g/hp-hr	GCP & Fuel Type
IN-0180	Midwest Fertilizer Company	6/4/14	Fire Pump	500 hp	0.14 g/hp-hr (3-hr avg.)	GCP

AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Diesel-Fired Well Pump Engine**	**2.7 MMBtu/hr**	0.36 lb/MMBtu 168 hr/yr	GCP & Limited Use
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Gasoline-Fired Fire Pump Engine**	**2.1 MMBtu/hr**	3.03 lb/MMBtu 168 hr/yr	Limited Use

RBLC Review
A review of similar units in the RBLC indicates good combustion practices are the principle VOC control technology for both diesel-fired and gasoline-fired pump engines.

Applicant Proposal
The applicant proposes the following as BACT:

(a) VOC emissions from the operation of the diesel-fired well pump and gasoline-fired fire water pump shall be controlled with limited use of the units.

(b) VOC emissions from the diesel-fired well pump shall not exceed 0.36 lb/MMBtu.

(c) VOC emissions from the gasoline-fired fire water pump shall not exceed 3.03 lb/MMBtu.

(d) Operating hours for EUs 65 and 66 shall not exceed 168 hours per year, each.

Step 5 – Selection of VOC BACT for the Well Pump and Fire Water Pump Engines
The Department agrees with the applicant that an emission rate achievable with limited use is BACT for the pump engines. VOC emissions from the diesel-fired well pump engine (EU 65) and the gasoline-fired fire pump engine (EU 66) shall not exceed 0.36 lb/MMBtu and 3.03 lb/MMBtu, respectively, and operating hours will be limited to 168 hours per year each. Compliance with the proposed emission limit will be demonstrated by recording total fuel usage and operating hours for the pump engines.

5.8 VOC BACT for the CO_2 Vent (EU 14)

Step 1 – Identification of VOC Control Technology for the CO_2 Vent
The Department has identified the following control technologies for the CO_2 purification process.

(a) Thermal Oxidizers
Regenerative thermal oxidation is effective at controlling VOC emissions and is typically used to control waste streams containing organics. Thermal oxidizers are designed to maintain a stable flame through combustion of a combination of waste gases, auxiliary fuel, and supplemental air. For the CO_2 vent the flow of gas to be controlled is very high and 96% of this stream is CO_2 with another 2% as water vapor. Neither of these constituents are combustible. Therefore, combustion of this stream to control the dilute amount of VOCs is technically infeasible.

(b) Flare
The heating value of the CO_2 vent exhaust is too low for flaring. As there are insufficient organics in this vent stream to support combustion and the use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of a flare for this stream would be the creation of additional emissions from burning supplemental fuel, including VOC.

(c) Proper Selection of Process Catalyst
The applicant can select a process catalyst that minimizes VOC emissions while maximizing the optimum catalytic conversion of CO to CO_2 in the high and low shift converters. The proper selection of a low VOC catalyst is a feasible control option for the CO_2 vent.

(d) Wet Scrubbers with Methanol Recovery
Wet scrubbing is an effective means of removing soluble or condensable organic vapors in a gas stream. Methanol is infinitely soluble in water and, under the right conditions, a wet scrubber could be used to remove methanol vapors from a gas stream. There are many different types of wet scrubbers, but the general concept is to create contact between the scrubbing liquid and the gas to maximize the mass transfer from the vapor phase to the liquid phase. For an application such as the CO_2 Vent a counter current packed bed scrubber would work best, although other designs and configurations are available. A packed bed scrubber is packed with media, usually spherical plastic shapes, used to disperse the downward flow of scrubbing liquid in the upward flow of gas. The spherical shapes increase the surface area of the scrubbing liquid, thus create more surface to gas contact.

The primary challenge with a wet scrubber in this application is that there is little opportunity to recycle the scrubber water – at some point the amount of methanol being absorbed in the scrubber water will equal the amount of methanol be stripped out of the scrubber water, and there will be no control provided by the scrubber. There are two ways to deal with this challenge: 1) do not recycle the water and have a once through scrubbing system, or 2) recover the methanol and recycle a portion of the water flow. As the name implies, a once through scrubber uses fresh water that contact the gas stream once and is discarded. This arrangement results in an extremely high water use rate give the volumetric flow of the gas stream and the low concentration of methanol in the air stream. In addition, in a once through scrubber the scrubbing water becomes a Wastewater that must be treated. The high water use is the reason that the once through scrubber configuration is not technically feasible for the CO_2 Vent.

To recover methanol one can use a distillation column to heat the water/methanol solution to above the methanol boiling point (148°F) and below the water boiling point (212°F), then condense out the collected methanol vapors. Conceptually this arrangement could allow for recirculation of the scrubber water after the methanol has been recovered and could be optimized to minimize water use and Wastewater generation. However, because the gas temperatures into and out of the scrubber, it is technically infeasible to design the scrubber to achieve significant or consistent control efficiency. Discussion with scrubber vendors has led to the conclusion that a wet scrubber with methanol recovery and recycle is not technically feasible.

(e) Refrigerated Condenser

A refrigerated condenser works by cooling the gas stream to a level where target compounds will condense and can be collected. To condense methanol at 500 ppmv to the point that methanol would be condensed, one would need to cool the gas stream from 122°F to -98°F. The electricity cost alone to achieve that level of cooling of the gas stream is estimated to be over $2,800,000 a year and results in over $63,500 per ton of methanol removed. This cost does not include the equipment cost and is still excessively high. For these reasons, a refrigerated condenser is not considered further in this analysis and is removed from consideration.

(f) Carbon Adsorption

Carbon adsorption works through a surface reaction between activated carbon and the target compound. Activated carbon has a high surface area for these reactions to occur. In addition, activated carbon has a unique affinity to adsorb each gas constituent known as the adsorption capacity. When the activated carbon becomes saturated (reaches the adsorption capacity for a given gas constituent) then the activated carbon must be regenerated by desorbing the adsorbed compounds. Desorption is accomplished by injecting steam or applying pressure shift in the bed. The adsorption capacity of activated carbon for methanol is 0.115 g/g and for CO_2 is 0.0088 g/g. Because CO_2 Vent is 96% CO_2 (by weight) the adsorption sites on the surface of the activated carbon would become saturated with CO_2 quickly and diminish the ability of the activated carbon to adsorb methanol. For this reason, activated carbon is eliminated from further consideration.

Step 2 – Eliminate Technically Infeasible VOC Control Options for the CO_2 Vent

As discussed in Section 5.8 the use of thermal oxidizers, flares, wet scrubbers with methanol recovery, refrigerated condensers, and carbon adsorption are technically infeasible options for controlling VOC emissions.

Step 3 – Ranking of the Remaining VOC Control Technologies for the CO_2 Vent

The applicant has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls

The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA CO_2 Vent (EU 14) – VOC						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
LA-0272	Dyno Nobel Louisiana	3/27/13	CO_2 Stripper Vent	115.83 tons/hour	21.78 lb/hr (hourly max) 95.38 tpy	GCP
IA-0105	Iowa Fertilizer Company	10/26/12	CO_2 Regenerator	3,012 metric tons/day	0.106 lb/ton of ammonia (3 stack test avg.)	Good Operational Practices
IN-0172	Ohio Valley Resources	9/25/13	CO_2 Purification Process	3,570 tons CO_2/day	0.0558 lb/ton of ammonia (3-hr avg.)	Low VOC Catalyst
IN-0179	Ohio Valley Resources	9/25/13	CO_2 Purification Process	3,570 tons CO_2/day	0.0558 lb/ton of ammonia (3-hr avg.)	Low VOC Catalyst
IN-0180	Midwest Fertilizer Company	6/4/14	CO_2 Purification Process	2,400 tons/day ammonia	0.0558 lb/ton of ammonia (3-hr avg.) 100% CO_2 venting	Proper Catalyst Selection
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**CO_2 Vent**	**90 tons/hour ammonia**	**11.4 lb/hr (hourly max)**	**Proper Selection of Process Catalyst**

RBLC Review

Entries in the RBLC table above, indicate add-on control devices are not included in the BACT determinations. The entries show BACT as the proper selection of a production catalyst and good operational practices.

Applicant Proposal

The applicant provided an economic analysis of the installation of a catalytic oxidizer on the CO_2 vent to demonstrate that the use of catalytic oxidation is not economically feasible on this unit. A summary of the analysis is shown below:

Control Alternative	Captured Emissions (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Operating Costs ($/year)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	50	49.5	$612,600	$1,247,440	$1,305,269	$26,105
Capital Recovery Factor = 0.0944 (7% for a 20 year life cycle)						

The economic analysis indicates the level of VOC reduction does not justify installing catalytic oxidizers on the CO_2 vent. Based on the excessive cost per ton of VOC removed per year, installation of catalytic oxidizers on the CO_2 vent is not considered a feasible option for reducing VOC emissions.

The applicant proposes the following as BACT:

(a) VOC emissions from the operation of the CO_2 vent shall be controlled by use of good operational procedures including the selection of an optimal process catalyst.

(b) VOC emissions from the CO_2 vent shall not exceed 11.4 lb/hr, based on a three-hour average and 100% venting.

Step 5 – Selection of VOC BACT for the CO_2 Vent
The Department agrees with the applicant that an emission rate achievable with good operational practices including the selection of an optimal process catalyst is BACT for the CO_2 vent. VOC emissions from the CO_2 vent (EU 14) shall not exceed 11.4 lb/hr.

5.9 VOC BACT for the Urea Granulation A/B and C/D (EUs 35 and 36)

Step 1 – Identification of VOC Control Technology for the Urea Granulation
From research, the Department identified the following technologies as available for VOC control of the Urea Granulation:

(a) Thermal Oxidizers
The theory of thermal oxidizers was discussed in detail in the VOC BACT for the primary reformer and will not be repeated here. A regenerative thermal oxidizer is retained for further evaluation. The methanol concentration in the exhaust stream following the wet scrubber will be less than 2 ppmv. As a result of the low VOC concentration in the exhaust, this control option is eliminated from further consideration.

(b) Catalytic Oxidizers
The theory of catalytic oxidizers was discussed in detail in the VOC BACT for the primary reformer and will not be repeated here. The technology relies on a precious metal catalyst to lower the energy required to oxidize VOC. The precious metal catalyst is susceptible to fouling - a process that limits the use of catalytic oxidizers. Fouling is where particulate matter is deposited on the surface of the catalyst and renders it ineffective. The exhaust gases leaving the Urea Granulation Plant contain particulates that may foul a catalyst, and the gas leaving the scrubbers will be saturated with water and gas cooling will result in condensation that will blind a carbon adsorption unit. Because of the high potential for fouling the use of a catalytic oxidizer is not a feasible control technology for the Urea Granulation.

(c) Wet Scrubbers
The theory of wet scrubbers was discussed in detail in the VOC BACT for the CO_2 vent and will not be repeated here. Wet scrubbers can achieve collection efficiencies from 70% to 99% depending on the physical characteristics of the waste gas stream. The use of wet scrubbers is a technologically feasible control device for the Urea Granulation.

Step 2 - Elimination of Technically Infeasible VOC Controls for Urea Granulation
As explained in Section 5.9, thermal oxidizers, and catalytic oxidizers are technically infeasible options for controlling VOC emissions.

Step 3 - Ranking of Remaining VOC Control Technologies for the Urea Granulation
The applicant has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 - Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in this table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Urea Granulation (EUs 35 and 36) – VOC						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
IA-0106	CF Industries Nitrogen, LLC	7/12/13	Urea Granulator	176.46 ton urea/hr (4,235 ton/day)	0.05 lb/ton urea (3 stack test avg.) 38.9 tpy	GCP & Wet Scrubber
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Urea Granulators**	**50 tons urea/hour**	**90% Control of Methanol, Methanol Concentration < 2ppmvd (whichever is less restrictive)**	**Wet Scrubber**

RBLC Review
A review of similar units in the RBLC indicates wet scrubbers are the principle VOC control devices installed on Urea Granulation.

Applicant Proposal
The applicant proposes the following as BACT:

(a) VOC emissions from the operation of granulation lines shall be controlled with the use of wet scrubbers.

(b) Wet scrubbers shall achieve a 90% control of methanol emissions or an outlet VOC concentration, as methanol, of < 2 ppm_{vd} (whichever is less restrictive).

(c) Compliance with the proposed emission limit will be demonstrated by conducting an initial stack test to obtain an emission rate.

Step 5 – Selection of VOC BACT for the Urea Granulation
The Department agrees with the applicant that an emission rate achievable with wet scrubbers is BACT for the Urea Granulation. VOC emissions from each of the Urea Granulation (EUs 35 and 36) shall be controlled by use of wet scrubbers and shall achieve a 90% control of methanol emissions or an outlet VOC concentration, as methanol, of < 2 ppm_{vd}, whichever is less restrictive.

5.10 VOC BACT for the Urea Formaldehyde Concentrate (UF-85) Storage Tank (EU 41A)

Step 1 – Identification of VOC Control Technology for the UF-85 Storage Tank
From research, the Department identified the following technologies as available for VOC control of the UF-85 storage tank:

(a) Wet Scrubber
The theory of wet scrubbers was discussed in detail in the VOC BACT for the CO_2 vent and will not be repeated here. The use of wet scrubbers is a technologically feasible control device for the UF-85 storage tank.

(b) Tank Design
Tank design features that can minimize VOC emissions include floating roof and submerged fill. Floating roof designs are utilized for storage of volatile organic liquids and include internal and external floating roof designs. These tanks minimize the head-space in a tank, thus eliminate losses from volatilization to the head-space. A floating roof tank is not a practical option for controlling VOC emissions from the UF-85 Tank at the Facility due to the low potential VOC emissions from the tank.

Step 2 - Elimination of Technically Infeasible VOC Controls for UF-85 Storage Tank
As explained in Section 5.10, thermal oxidizers and catalytic oxidizers are technically infeasible options for controlling VOC emissions.

Step 3 - Ranking of Remaining VOC Control Technologies for the UF-85 Storage Tank
The applicant has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 - Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in this table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA UF-85 Storage Tank (EU 41A) – VOC						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
IA-0106	CF Industries Nitrogen, LLC	7/12/13	Urea UF-85 Storage Tank	79,250 gallons	0.046 lb/hr (3 stack test avg.)	Packed Bed Scrubber
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**UF-85 Storage Tank**	**50 tons urea/hour**	**0.00004 lb/hr (3 stack test avg.)**	**Wet Scrubber**

RBLC Review
A review of similar units in the RBLC indicates wet scrubbers are the principle VOC control devices installed on UF-85 storage tanks.

Applicant Proposal
The applicant proposes the following as BACT:

(a) VOC emissions from the UF-85 storage tank shall be controlled with the use of a wet scrubber when filling the tank.

(b) VOC emissions from the UF-85 storage tank shall not exceed 0.00004 lb/hr.

Step 5 – Selection of VOC BACT for the UF-85 Storage Tank
The Department agrees with the applicant that an emission rate achievable with wet scrubbers is BACT for the UF-85 storage tank. VOC emissions from each of the UF-85 storage tank (EU 41A) shall be controlled by use of wet scrubbers and shall not exceed 0.00004 lb/hr.

5.11 VOC BACT for the Methyl-diethanol Amine (MDEA) Storage Tanks (EUs 41B and 41C)

Step 1 – Identification of VOC Control Technology for the MDEA Storage Tank
From research, the Department identified the following technologies as available for VOC control of the MDEA storage tank:

(a) Thermal Oxidizers
For the purpose of this discussion, thermal oxidizers refer to combustion devices designed to oxidize VOC in a gas stream. Generally these devices fall into three categories – regenerative or recuperative thermal oxidizers, flares, and catalytic oxidizers.

Regenerative and recuperative thermal oxidizers operate in the range of 1,000°F to 2,000°F. In general, thermal oxidizers and process boilers handle gas streams with inlet organic vapor concentrations less than 25% to 50% of their Lower Explosive Limit (LEL) of the VOC. Both regenerative and recuperative designs include features to optimize the heat balance around the device and minimize the purchased energy input. Regenerative designs employ a heat storage media and recuperative designs include heat recovery through heat exchangers. Flares are used for the combustion of organic vapor Waste streams that have concentrations greater than 100% of the Upper Explosive Limit (UEL). Finally, catalytic oxidation processes operate at temperatures ranging from 400°F to 1,000°F and are designed for gases containing less than 25% of the LEL. As the name implies, catalytic oxidizers use a catalyst, usually a precious metal, to lower the activation energy required for oxidation of the VOC to occur.

None of these thermal oxidizer technologies are applied to controlling tank emissions. Tank emissions occur during tank filling where head-space displacement occurs (working loss), and due to temperature fluctuations of the tank shell (breathing loss). These types of losses from tank storage are low level and intermittent. The anticipated annual VOC emissions from the MDEA Storage Tanks are estimated to be less than one pound per year per tank due to the low volatility of MDEA (less than 0.01 mm Hg at 20°C). Due to the low level of emissions from the MDEA Storage Tanks, the use of thermal oxidation technologies are technically infeasible and are eliminated from further consideration for control of VOC emissions from the MDEA Storage Tanks.

(b) Carbon Adsorption
Vapor-phase carbon adsorption utilizes activated carbon to capture VOC emissions. Activated carbon is riddled with small, low-volume pores that increase the surface area available for adsorption or chemical reactions. It is on the surface of the microspores in activated carbon that VOC molecules are captured. Over the course of operation activated carbon will reach an adsorption capacity and must be replaced or regenerated in place. Regeneration is accomplished by thermally treating the activated carbon to drive the adsorbed material from the adsorption sites on the surface. Placement of an activated carbon adsorption unit on the MDEA Storage Tank would create a pressure drop across the tank vent and interfere with the proper operation of the tank. Such interference could cause tank pressurization and result in safety concerns for process operation. In addition, due to the low level of emissions from the MDEA Storage Tanks, the use of carbon adoption is technically infeasible and is eliminated from further consideration for control of VOC emissions from the MDEA Storage Tanks.

(c) Tank Operation
The VOC losses to the atmosphere during filling of an organic material storage tank can be eliminated through a vapor balance system. A vapor balance system captures the vapors in the head-space of the tank during tank filling by routing the head-space displacement to the tanker truck filling the tank. This type of system is used for high vapor pressure materials and is not typically used for material transfers of organic compounds such as MDEA (vapor pressure less than 0.01 in Hg). Because vapor balance systems are not used for MDEA storage tank filling systems and due to the low level of emissions from the MDEA Storage Tanks, a vapor balance system is eliminated from further consideration as representing BACT for VOC emissions from the MDEA Storage Tanks.

(d) Tank Design
The theory of tank design was discussed in detail in the VOC BACT for the UF-85 Storage Tank and will not be repeated here. A floating roof tank is not a practical option for controlling VOC emissions from the MDEA Storage Tanks at the Facility due to the low volatility of MDEA and the potential process upsets that a mechanical (moving) tank design entails. Submerged fill is a tank design feature that minimizes the volatilization of organic compounds due to splashing. This is a planned design feature of the MDEA Storage Tanks at the Facility, thus a baseline VOC control.

Step 2 - Elimination of Technically Infeasible VOC Controls for MDEA Storage Tank
As explained in Section 5.11, thermal oxidizers, carbon adsorption, and tank operation are technically infeasible options for controlling VOC emissions.

Step 3 - Ranking of Remaining VOC Control Technologies for the MDEA Storage Tank
The applicant has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 - Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in this table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA

RACT/BACT/LAER Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA MDEA Storage Tanks (EU 41B and 41C) – VOC						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
IA-0106	CF Industries Nitrogen, LLC	7/12/13	MDEA Storage Tank	220,000 gallons	0.1 tpy (rolling 12-month total)	Nitrogen Gas Blanket
IA-0105	Iowa Fertilizer Company	10/26/12	MDEA Storage Tank	390,000 gallons	0.1 tpy (rolling 12-month total)	Nitrogen Gas Blanket
LA-0272	Dyno Nobel Louisiana Ammonia, LLC	3/27/13	AMDEA	395,000 gallons	None (emits 0.003 tpy)	None
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Two MDEA Storage Tanks**	**158,420 gallons** **16,000 gallons**	**0.002 tpy (combined)**	**Submerged Fill Design**

RBLC Review

A review of similar units in the RBLC indicates nitrogen gas blankets are the principle VOC control devices installed on MDEA storage tanks. Due to the low emission rates generated by the MDEA storage tanks and because the tanks are existing units, the applicant proposes submerged fill design to control VOC emissions from the two tanks.

Applicant Proposal

The applicant proposes the following as BACT:

(a) VOC emissions from the MDEA storage tanks shall be controlled with the use of submerged fill design.

(b) VOC emissions from the MDEA storage tanks shall not exceed 0.002 tons per year.

Step 5 – Selection of VOC BACT for the MDEA Storage Tanks

The Department agrees with the applicant that an emission rate achievable with submerged fill design is BACT for the MDEA storage tank. VOC emissions from each of the MDEA storage tanks (EUs 41B and 41C) shall be controlled by use of submerged fill design and shall not exceed 0.002 tons per year.

6.0 BACT Determination for PM, PM-10, and PM-2.5

The KNO facility has five existing 37.6 MMBtu/hr Solar Centaur GSC-4000 turbines that burn natural gas, one 1,350 MMBtu/hr primary reformer, heaters, boilers, flares, and several other EUs subject to BACT. The Department reviewed the control technologies Agrium identified in their application and determined PM, PM-10, and PM-2.5 BACT for the EUs listed in Table B-1.

The Department based its assessment on BACT determinations found in the RBLC and internet research. Table B-5 summarizes PM BACT determinations in the RBLC for the proposed EUs.

Table B-5: PM BACT Determinations in RBLC for January 2004-August 8, 2014

Description of NOx BACT	Fuel Gas Turbines	Primary Reformer	Startup Heater	Boilers	Flares	Cooling Towers	Well and Fire Pump	Urea Granulators, Transfer, and Loading
Good Combustion Practices		9	6	14	4		9	6
Good Operating Practices		6	6	9	4			4
Equipment Design		4	3	4	10			
Wet Scrubbers								16
Drift Eliminators						19		
Bin Vent Filter								9
Clean Fuels	6						5	
Total	**6**	**19**	**15**	**27**	**18**	**19**	**14**	**35**

6.1 PM, PM-10, and PM-2.5 BACT for the Turbines (EUs 55 through 59)

Step 1- Identification of PM, PM-10, and PM-2.5 Control Technology for the Turbines
From research, the Department identified the following technologies as available for PM, PM-10, and PM-2.5 control of turbines rated at 25 MW or less:

(a) Fabric Filters
Fabric filters or baghouses are comprised of an array of filter bags contained in housing. Air passes through the filter media from the "dirty" to the "clean" side of the bag. These devices undergo periodic bag cleaning based on the build-up of filtered material on the bag as measured by pressure drop across the device. The cleaning cycle is set to allow operation within a range of design pressure drop. Fabric filters are characterized by the type of cleaning cycle - mechanical-shaker, pulse-jet, and reverse-air. Fabric filter systems have control efficiencies of 95% to 99.9% (EPA-452/F-03-024, EPA-452/F-03-025, and EPA-452/F-03-026, Air Pollution Control Technology Fact Sheets for Fabric Filters), and are generally specified to meet a discharge concentration of filterable particulate (e.g., 0.01 grains per dry standard cubic feet). Because the filterable particulate emissions resulting from natural gas combustion are so low (0.007 gr/dscf), fabric filters would not achieve any appreciable particulate control. Hence the Department does not consider fabric filters as a feasible control technology for the turbines.

(b) Cartridge Collectors
Cartridge Collectors involve the use of filter media supported on a wire framework to collect filterable particulate matter from an air stream or exhaust. Typical Cartridge Collectors have control efficiencies of 99.99% to 99.999% (EPA-452/F-03-004, Air Pollution Control Technology Fact Sheet for Cartridge Collectors). Use of a HEPA type filter can achieve even greater control efficiency. Cartridge collectors generally do not have a means of self-cleaning and are replaced when the pressure drop across the filter becomes excessive and impedes air flow or fan operation. Cartridge filters are not practical for use to control emissions from a continuous operation and have never been used to control filterable particulate emissions from a natural gas combustion source. Hence the Department does not consider the use of cartridge collectors as a feasible control technology for the turbines.

(c) Mechanical Separators

Separators are often referred to as "pre-cleaners," and are typically used to reduce the inlet loading of $PM/PM_{10}/PM_{2.5}$ to control devices further downstream by removing large particles. Typical inlet grain loading values for separators are 4 – 110 gr/scf (EPA-452/F-03-007, Air Pollution Control Technology Fact Sheet for Mechanically-Aided Separators). Because the filterable particulate emissions resulting from natural gas combustion are so low (0.007 gr/dscf), mechanical separators would not achieve any appreciable particulate control. Therefore, the Department does not consider mechanical separators as a technically feasible control technology for the turbines.

(d) Wet and Dry Electrostatic Precipitators

Wet and Dry Electrostatic Precipitators (ESPs) remove particles from a gas stream by electrically charging particles with a discharge electrode in the gas path and then collecting the charged particles on grounded. The inlet air is quenched with water on a Wet ESP to saturate the gas stream and ensure a wetted surface on the collection plate. This wetted surface along with a period deluge of water is what cleans the collection plate surface. Wet ESPs typically control streams with inlet grain loading values of 0.5 – 5 gr/ft^3 and have control efficiencies between 90% and 99.9% (EPA-452/F-03-027, EPA-452/F-03-028, EPA-452/F-03-029, and EPA-452/F-03-030, Air Pollution Control Technology Fact Sheets for Electrostatic Precipitators). Wet ESPs have the advantage of controlling some amount of condensable particulate matter. The collection plates in a Dry ESP are periodically cleaned by a rapper or hammer that sends a shock wave that knocks the collected particulate off the plate. Dry ESPs typically control streams with inlet grain loading values of 0.5 – 5 gr/ft^3 and have control efficiencies between 99% and 99.9%. Due to the low level of particulate matter emissions, the Department does not consider the use of wet and dry ESPs to be a technically feasible control technology for the turbines.

(e) Wet Scrubbers

Wet Scrubbers use a scrubbing solution to remove $PM/PM_{10}/PM_{2.5}$ from exhaust gas streams. The mechanism for particulate collection is impaction and interception by water droplets. Wet Scrubbers are configured as counter-flow, cross-flow, or concurrent flow, but typically employ counter-flow where the scrubbing fluid is in the opposite direction as the gas flow. Wet Scrubbers have control efficiencies of 50% - 99%. One advantage of wet Scrubbers is that they can be effective on condensable particulate matter. A disadvantage of a Wet Scrubber is that they consume water and produce water and sludge. For fine particulate control, a venturi scrubber can be used, but typical loadings for such a scrubber are 0.1-50 grains/scf (EPA-452/F-03-010, EPA-452/F-03-011, and EPA-452/F-03-017, Air Pollution Control Technology Fact Sheet for Venturi Scrubber). Since the concentration of this stream (0.007 gr/dscf) is already orders of magnitude lower, a wet scrubber would not achieve any appreciable particulate control. Therefore, the Department does not consider the use of wet scrubbers to be a technically feasible control technology for the turbines.

(f) Fuel Specifications
Natural gas combustion turbines are among the cleanest fossil-fuel fired power generation equipment commercially available. Particulate matter 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 combustion turbines.

(g) Good Combustion Practices
The theory of GCP was discussed in detail in the NOx BACT for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of PM. Therefore good combustion practices is a feasible control option for the turbines.

Step 2 - Elimination of Technically Infeasible PM Control Options for Turbines
As explained in Section 6.1, fabric filters, cartridge collectors, mechanical separators, wet and dry electrostatic precipitators (ESP), and wet scrubbers are not feasible to control PM emissions from the turbines.

Step 3 - Ranking of Remaining PM, PM-10, and PM-2.5 Control Technologies for Turbines
The applicant has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 - Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units (combustion turbines rated at less than 25 MW). All data in this table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Solar Combustion Turbines (EUs 55 through 59) – PM/PM-10/PM-2.5						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
NY-0101	Cornell University	3/12/08	Combustion Turbine	155 MMBtu/hr	PM-10 and PM-2.5 6.7 lb/hr (1-hr avg.), PM 6.5 lb/hr (1-hr avg.), 0.023 lb/MMBtu	Sulfur Limit & Work Practice
NY-0101	Cornell University	3/12/08	Combustion Turbine	155 MMBtu/hr	PM-10 4.1 lb/hr (1-hr avg.), PM-2.5 and PM 3.9 lb/hr (1-hr avg.), 0.023 lb/MMBtu	Sulfur Limit & Work Practice
NY-0101	Cornell University	3/12/08	Combustion Turbine	155 MMBtu/hr	PM/PM-10/PM-2.5 6.3 lb/hr (1-hr avg.)	Sulfur Limit & Work Practice

NY-0101	Cornell University	3/12/08	Combustion Turbine	155 MMBtu/hr	PM/PM-10/PM-2.5 8.3 lb/hr > 0º F 8.6 lb/hr < 0º F (1-hr avg.)	Sulfur Limit & Work Practice
IN-0180	Midwest Fertilizer Corporation	6/4/14	Two Combustion Turbines	283 MMBtu/hr (each)	PM 0.0019 lb/MMBtu (3-hr avg.), PM-10 and PM-2.5 0.0076 lb/MMBtu (3-hr avg.)	GCP & Design
TX-0497	Ineos Chocolate Bayou Facility	4/3/12	Two Cogeneration Combustion Turbines	35 MW (each)	PM-10 10.03 lb/hr, 71.32 tpy	Combustion Control & Fuel Type
LA-0256	Westlake Vinyls Company	12/6/11	Three Cogeneration Combustion Turbines	50 MMBtu (each)	PM/PM-10/PM-2.5 3.72 lb/hr, 16.31 tpy	GCP & Fuel Type
VA-0319	Gateway Green Energy	5/2/13	Two Combustion Turbines	593 MMBtu/hr	PM-10 and PM-2.5 5.0 lb/hr (3-hr avg.)	GCP & Fuel Type
LA-0194	Sabine Pass LNG Terminal	11/24/04	Four Gas Turbine Generators	30 MW (each)	PM-10 2.11 lb/hr (hourly maximum), 8.5 tpy	GCP & Fuel Type
WY-0070	Black Hills Power, Inc.	8/27/12	Two Combined Cycle Turbines	40 MW (each)	PM 4 lb/hr (3-hr avg.), 17.5 tpy	GCP
NE-0017	Beatrice Power Station	8/3/04	Two Combustion Turbines with HRSG	80 MW (each)	PM 10.8 lb/hr	Unknown
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Five Gas Combustion Turbines**	**37.6 MMBtu/hr (each)**	PM/PM-10/PM-2.5 0.0074 lb/MMBtu (3-hr avg.)	None

RBLC Review
A review of similar units in the RBLC indicates restrictions on fuel sulfur contents and good combustion practices are the principle PM control technologies installed on gas turbines.

Applicant Proposal
The applicant proposes the following as BACT:

(a) PM, PM-10, and PM-2.5 emissions from the natural gas fired turbines shall not exceed 0.0074 lb/MMBtu, based on a three-hour average.

Step 5 – Selection of PM BACT for the Turbines
The Department agrees with the applicant that an emission rate achievable with no controls is BACT for the turbines. PM emissions from each of the natural gas fired combustion turbines (EUs 55 through 59) shall not exceed 0.0074 lb/MMBtu, based on a three-hour average.

6.2 PM, PM-10, and PM-2.5 BACT for the Primary Reformer (EU 12)

Step 1 – Identification of PM Control Technology for the Primary Reformer
From research, the Department identified the following technologies as available for PM control of reformer furnaces:

(a) Fabric Filters
The theory behind fabric filters was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Because the filterable particulate emissions resulting from natural gas combustion are so low (0.007 gr/dscf), fabric filters would not achieve any appreciable particulate matter control. Hence the Department does not consider Fabric Filters as a feasible control technology for the primary reformer.

(b) Cartridge Collectors
The theory behind cartridge collectors was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Cartridge filters are not a practical technology for control of particulate matter emissions from a continuous operation and have never been used to control filterable particulate emissions from a natural gas combustion source. Hence the Department does not consider the use of cartridge collectors as a feasible control technology for the primary reformer.

(c) Mechanical Separators
The theory behind mechanical separators was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Because the filterable particulate emissions resulting from natural gas combustion are so low (0.007 gr/dscf), mechanical separators would not achieve any appreciable particulate matter control. Therefore, the Department does not consider mechanical separators as a technically feasible control technology for the primary reformer.

(d) Wet and Dry Electrostatic Precipitators
The theory behind ESPs was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Due to the low level of particulate matter emissions, the Department does not consider the use of wet and dry ESPs to be a technically feasible control technology for the primary reformer.

(e) Wet Scrubbers
The theory behind wet scrubbers was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Due to the low level of particulate matter emissions, the Department does not consider the use of wet scrubbers a technically feasible control technology for the primary reformer.

(f) Fuel Specifications
The theory behind fuel specifications was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. The Department considers fuel specifications as a technically feasible control technology for the primary reformer.

(g) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of NOx emissions. GCPs is considered a technically feasible control option for the primary reformer.

Step 2 – Eliminate Technically Infeasible PM Control Options for the Primary Reformer
As explained in Section 6.2, fabric filters, cartridge collectors, mechanical separators, wet and dry electrostatic precipitators (ESP), and wet scrubbers are not feasible to control PM emissions from the primary reformer.

Step 3 - Ranking of Remaining PM, PM-10, and PM-2.5 Control Technologies for Turbines
The applicant has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA
Primary Reformer (EU 12) – PM/PM-10/PM-2.5

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
TX-0657	Beaumont Gas to Gasoline Plant	5/16/14	Primary Reformer	1,552 MMBtu/hr	PM-10 and PM 43.72 tpy PM-2.5 32.79 tpy	GCP & Fuel Type
LA-0272	Dyno Nobel Louisiana Ammonia	3/27/13	Primary Reformer	956.2 MMBtu/hr	PM-10 and PM-2.5 8.55 lb/hr 31.21 tpy	GCP & Design
IA-0105	Iowa Fertilizer Company	10/26/12	Primary Reformer	1,152.6 MMBtu/hr	PM/PM-10/PM-2.5 0.0024 lb/MMBtu 11.9 tpy	GCP
IN-0172	Ohio Valley Resources	9/25/13	Primary Reformer	1,006.4 MMBtu/hr	PM 1.9 lb/MMscf (3-hr avg.) PM-10 and PM-2.5 7.6 lb/MMscf (3-hr avg.)	GCP
OK-0134	Pryor Plant Chemical Company	2/23/09	Primary Reformer	700 ton ammonia/day 225 MMBtu/hr	PM 1.68 lb/hr PM-10 1.26 lb/hr	None
LA-0211	Garyville Refinery	12/27/06	Hydrogen Reformer	1,412.5 MMBtu/hr	PM-10 0.0075 lb/MMBtu (3-hr avg.)	Proper Design, Operation, and Good Engineering Practices
NM-0050	Artesia Refinery	12/14/07	Methane Reformer Heater	337 MMBtu/hr	PM-10 0.0075 lb/MMBtu (hourly)	Fuel Type

IN-0180	Midwest Fertilizer Corporation	6/4/14	Reformer Furnace	950.64 MMBtu/hr	PM 1.9 lb/MMscf (3-hr avg.) PM-10 and PM-2.5 5.385 lb/MMscf (3-hr avg.)	GCP & Design
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Primary Reformer**	**1,350 MMBtu/hr**	**PM/PM-10/PM-2.5 0.0074 lb/MMBtu (3-hr avg.)**	**None**

RBLC Review
Most of the RBLC control method entries for reformer furnaces list the use of proper design, fuel specifications, and good combustion practices as BACT for reformer furnaces.

Applicant Proposal
The applicant proposes the following as BACT:

(a) PM, PM-10, and PM-2.5 emissions from the primary reformer shall not exceed 0.0074 lb/MMBtu, based on a three-hour average.

Step 5 – Selection of PM, PM-10, and PM-2.5 BACT for the Primary Reformer
The Department agrees with the applicant that an emission rate achievable with no controls is BACT for the primary reformer. PM emissions from the primary reformer (EU 12) shall not exceed 0.0074 lb/MMBtu based on a three-hour average.

6.3 PM, PM-10, and PM-2.5 BACT for the Package Boilers (EUs 44, 48, and 49)

Step 1 – Identification of PM Control Technology for the Package Boilers
From research, the Department identified the following technologies as available for PM control for package boilers:

(a) Fabric Filters
The theory behind fabric filters was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Because the filterable particulate emissions resulting from natural gas combustion are so low (0.007 gr/dscf), fabric filters would not achieve any appreciable particulate matter control. Hence the Department does not consider fabric filters as a feasible control technology for the package boilers.

(b) Cartridge Collectors
The theory behind cartridge collectors was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Cartridge filters are not a practical technology for control of particulate matter emissions from a continuous operation and have never been used to control filterable particulate emissions from a natural gas combustion source. Hence the Department does not consider the use of cartridge collectors as a feasible control technology for the package boilers.

(c) Mechanical Separators
The theory behind mechanical separators was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Because the filterable particulate emissions resulting from natural gas combustion are so low (0.007 gr/dscf), mechanical separators would not achieve any appreciable particulate matter control. Therefore, the Department does not consider mechanical separators as a technically feasible control technology for the package boilers.

(d) Wet and Dry Electrostatic Precipitators
The theory behind ESPs was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Due to the low level of particulate matter emissions, the Department does not consider the use of wet and dry ESPs to be a technically feasible control technology for the package boilers.

(e) Wet Scrubbers
The theory behind wet scrubbers was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Due to the low level of particulate matter emissions, the Department does not consider the use of wet scrubbers a technically feasible control technology for the package boilers.

(f) Fuel Specifications
The theory behind fuel specifications was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. The Department considers fuel specifications as a technically feasible control technology for the package boilers.

(g) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of NOx emissions. GCPs is considered a technically feasible control option for the package boilers.

Step 2 – Eliminate Technically Infeasible PM Control Options for the Package Boilers
As explained in Section 6.3, fabric filters, cartridge collectors, mechanical separators, wet and dry electrostatic precipitators (ESP), and wet scrubbers are not feasible to control PM emissions from the package boilers.

Step 3 – Ranking of the Remaining PM Control Technologies for the Package Boilers
The applicant has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Package Boilers (EUs 44, 48, and 49) – PM/PM-10/PM-2.5						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
NC-0101	Forsyth Energy Plant	9/29/05	Auxiliary Boiler	110.2 MMBtu/hr	PM-10 0.82 lb/hr (3-hr avg.) 0.007 lb/MMBtu	DLN, GCP, & Fuel Type
NJ-0043	Liberty Generating Station	3/28/02	Auxiliary Boiler	200 MMBtu/hr	PM-10 1.6 lb/hr, 0.008 lb/MMBtu (maximum)	Unknown
LA-0231	Lake Charles Cogeneration	6/22/09	Auxiliary Boiler	938 MMBtu/hr	PM-10 6.99 lb/hr, max	GCP & Design
LA-0272	Dyno Nobel Louisiana Ammonia	3/27/13	Commissioning Boilers	217.5 MMBtu/hr	PM-10 and PM-2.5 1.94 lb/hr (hourly maximum) 3.57 tpy	GCP & Design
IA-0105	Iowa Fertilizer Company	10/26/12	Auxiliary Boiler	472.4 MMBtu/hr	PM/PM-10/PM-2.5 0.0024 lb/MMBtu (3-test avg.) 1.06 tpy (12-month rolling)	GCP
IN-0172	Ohio Valley Resources	9/25/13	Natural Gas-Fired Boilers	218 MMBtu/hr	PM 1.9 lb/MMcf (3-hr avg.) PM-10 and PM-2.5 7.6 lb/MMcf (3-hr avg.)	GCP & Design
OK-0307	Biomass Energy South Point	4/4/06	Auxiliary Boiler	227 MMBtu/hr	PM-10 9.08 lb/hr 3.26 tpy	Unknown
OK-0135	Pryor Plant Chemical Company	2/23/09	Boilers #1 & #2	80 MMBtu/hr	PM 0.6 lb/hr, PM-10 0.5 lb/hr (24-hr)	Unknown
PA-0187	Gray's Ferry Cogen Partnership	3/21/01	Auxiliary Boiler	1119 MMBtu/hr	PM and PM-10 0.005 lb/MMBtu 34.4 lb/hr	GCP
ID-0017	Southeast Idaho Energy	2/10/09	Package Boiler	250 MMBtu/hr	PM and PM-10 0.0052 lb/MMBtu 1.3 lb/hr	Unknown
TX-0371	Corpus Christi Energy Center	2/4/00	Three Auxiliary Boilers	315 MMBtu/hr	PM-10 1.57 lb/hr 0.005 lb/MMBtu	Unknown
TX-0386	Amella Energy Center	3/26/02	Auxiliary Boiler	155 MMBtu/hr	PM-10 3.23 lb/hr 0.02 lb/MMBtu	Unknown

TN-0153	Williams Refining and Marketing	4/3/12	Boiler No. 9	95 MMBtu/hr	PM-10 0.0075 lb/MMBtu	Unknown
IN-0180	Midwest Fertilizer Corporation	6/4/14	Auxiliary Boiler	218.6 MMBtu/hr	PM 1.9 lb/MMcf (3-hr avg.) PM-10 and PM-2.5 7.6 lb/MMcf (3-hr avg.), 2,800 MMcf/ 12-months rolling	GCP & Design
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Package Boilers**	**243 MMBtu/hr**	**PM/PM-10/PM-2.5** **0.0074 lb/MMBtu** **(3-hr avg.)**	**None**

RBLC Review
A review of similar units in the RBLC indicates all of the auxiliary boilers in the RBLC are controlled by good combustion practices. Particulate emissions from natural gas-fired combustion sources are already extremely low and add-on controls are not practical.

Applicant Proposal
The applicant proposes the following as BACT:

(a) PM, PM-10, and PM-2.5 emissions from the natural gas fired package boilers shall not exceed 0.0074 lb/MMBtu, based on a three-hour average.

Step 5 – Selection of PM, PM-10, and PM-2.5 BACT for the Package Boilers
The Department agrees with the applicant that an emission rate achievable with no controls is BACT for the package boilers. PM emissions from the package boilers (EUs 44, 48, and 49) shall not exceed 0.0074 lb/MMBtu, based on a three-hour average.

6.4 PM, PM-10, and PM-2.5 BACT for the Waste Heat Boilers (EUs 50 through 54)

Step 1 – Identification of PM Control Technology for the Waste Heat Boilers
From research, the Department identified the following technologies as available for PM control for three waste heat boilers:

(a) Fabric Filters
The theory behind fabric filters was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Because the filterable particulate emissions resulting from natural gas combustion are so low (0.007 gr/dscf), fabric filters would not achieve any appreciable particulate matter control. Hence the Department does not consider Fabric Filters as a feasible control technology for the waste heat boilers.

(b) Cartridge Collectors
The theory behind cartridge collectors was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Cartridge filters are not a practical technology for control of particulate matter emissions from a continuous operation and have never been used to control filterable particulate emissions from a natural gas combustion source. Hence the Department does not consider the use of cartridge collectors as a feasible control technology for the waste heat boilers.

(c) Mechanical Separators
The theory behind mechanical separators was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Because the filterable particulate emissions resulting from natural gas combustion are so low (0.007 gr/dscf), mechanical separators would not achieve any appreciable particulate matter control. Therefore, the Department does not consider mechanical separators as a technically feasible control technology for the waste heat boilers.

(d) Wet and Dry Electrostatic Precipitators
The theory behind ESPs was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Due to the low level of particulate matter emissions, the Department does not consider the use of wet and dry ESPs to be a technically feasible control technology for the waste heat boilers.

(e) Wet Scrubbers
The theory behind wet scrubbers was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Due to the low level of particulate matter emissions, the Department does not consider the use of wet scrubbers a technically feasible control technology for the waste heat boilers.

(f) Fuel Specifications
The theory behind fuel specifications was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. The Department considers fuel specifications as a technically feasible control technology for the waste heat boilers.

(g) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of NOx emissions. GCPs is considered a technically feasible control option for the waste heat boilers.

Step 2 – Eliminate Technically Infeasible PM Control Options for the Waste Heat Boilers
As explained in Section 6.4, fabric filters, cartridge collectors, mechanical separators, wet and dry ESPs, and wet scrubbers are not feasible to control PM emissions from the package boilers.

Step 3 – Ranking of the Remaining PM Control Technologies for the Waste Heat boilers
The applicant has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Waste Heat Boilers (EUs 50 through 54) – PM/PM-10/PM-2.5						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
NC-0101	Forsyth Energy Plant	9/29/05	Auxiliary Boiler	110.2 MMBtu/hr	PM-10 0.82 lb/hr (3-hr avg.) 0.007 lb/MMBtu	DLN, GCP, & Fuel Type
NJ-0043	Liberty Generating Station	3/28/02	Auxiliary Boiler	200 MMBtu/hr	PM-10 1.6 lb/hr, 0.008 lb/MMBtu (maximum)	Unknown
LA-0231	Lake Charles Cogeneration	6/22/09	Auxiliary Boiler	938 MMBtu/hr	PM-10 6.99 lb/hr, max	GCP & Design
LA-0272	Dyno Nobel Louisiana Ammonia	3/27/13	Commissioning Boilers	217.5 MMBtu/hr	PM-10 and PM-2.5 1.94 lb/hr (hourly maximum) 3.57 tpy	GCP & Design
IA-0105	Iowa Fertilizer Company	10/26/12	Auxiliary Boiler	472.4 MMBtu/hr	PM/PM-10/PM-2.5 0.0024 lb/MMBtu (3-test avg.) 1.06 tpy (12-month rolling)	GCP
IN-0172	Ohio Valley Resources	9/25/13	Natural Gas-Fired Boilers	218 MMBtu/hr	PM 1.9 lb/MMcf (3-hr avg.) PM-10 and PM-2.5 7.6 lb/MMcf (3-hr avg.)	GCP & Design
OK-0307	Biomass Energy South Point	4/4/06	Auxiliary Boiler	227 MMBtu/hr	PM-10 9.08 lb/hr 3.26 tpy	Unknown
OK-0135	Pryor Plant Chemical Company	2/23/09	Boilers #1 & #2	80 MMBtu/hr	PM 0.6 lb/hr, PM-10 0.5 lb/hr (24-hr)	Unknown
PA-0187	Gray's Ferry Cogen Partnership	3/21/01	Auxiliary Boiler	1119 MMBtu/hr	PM and PM-10 0.005 lb/MMBtu 34.4 lb/hr	GCP
ID-0017	Southeast Idaho Energy	2/10/09	Package Boiler	250 MMBtu/hr	PM and PM-10 0.0052 lb/MMBtu 1.3 lb/hr	Unknown

TX-0371	Corpus Christi Energy Center	2/4/00	Three Auxiliary Boilers	315 MMBtu/hr	PM-10 1.57 lb/hr 0.005 lb/MMBtu	Unknown
TX-0386	Amella Energy Center	3/26/02	Auxiliary Boiler	155 MMBtu/hr	PM-10 3.23 lb/hr 0.02 lb/MMBtu	Unknown
TN-0153	Williams Refining and Marketing	4/3/12	Boiler No. 9	95 MMBtu/hr	PM-10 0.0075 lb/MMBtu	Unknown
IN-0180	Midwest Fertilizer Corporation	6/4/14	Auxiliary Boiler	218.6 MMBtu/hr	PM 1.9 lb/MMcf (3-hr avg.) PM-10 and PM-2.5 7.6 lb/MMcf (3-hr avg.), 2,800 MMcf/ 12-months rolling	GCP & Design
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Waste Heat Boilers**	**50 MMBtu/hr**	**PM/PM-10/PM-2.5** **0.0074 lb/MMBtu** **(3-hr avg.)**	**None**

RBLC Review
A review of similar units in the RBLC indicates all of the auxiliary boilers in the RBLC are controlled by good combustion practices. Particulate emissions from natural gas-fired combustion sources are already extremely low and add-on controls are not practical.

Applicant Proposal
The applicant proposes the following as BACT:

(a) PM, PM-10, and PM-2.5 emissions from the waste heat boilers shall not exceed 0.0074 lb/MMBtu, based on a three-hour average.

Step 5 – Selection of PM, PM-10, and PM-2.5 BACT for the Waste Heat Boilers
The Department agrees with the applicant that an emission rate achievable with no controls is BACT for the waste heat boilers. PM emissions from the waste heat boilers (EUs 50 through 54) shall not exceed 0.0074 lb/MMBtu, based on a three-hour average.

6.5 PM, PM-10, and PM-2.5 BACT for the Startup Heater (EU 13)

Step 1 – Identification of PM Control Technology for the Startup Heater
From research, the Department identified the following technologies as available for PM control of startup heaters:

(a) Fabric Filters
The theory behind fabric filters was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Because the filterable particulate emissions resulting from natural gas combustion are so low (0.007 gr/dscf), fabric filters would not achieve any appreciable particulate matter control. Hence the Department does not consider Fabric Filters as a feasible control technology for the startup heater.

(b) Cartridge Collectors
The theory behind cartridge collectors was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Cartridge filters are not a practical technology for control of particulate matter emissions from a continuous operation and have never been used to control filterable particulate emissions from a natural gas combustion source. Hence the Department does not consider the use of cartridge collectors as a feasible control technology for the startup heater.

(c) Mechanical Separators
The theory behind mechanical separators was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Because the filterable particulate emissions resulting from natural gas combustion are so low (0.007 gr/dscf), mechanical separators would not achieve any appreciable particulate matter control. Therefore, the Department does not consider mechanical separators as a technically feasible control technology for the startup heater.

(d) Wet and Dry Electrostatic Precipitators
The theory behind ESPs was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Due to the low level of particulate matter emissions, the Department does not consider the use of wet and dry ESPs to be a technically feasible control technology for the startup heater.

(e) Wet Scrubbers
The theory behind wet scrubbers was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Due to the low level of particulate matter emissions, the Department does not consider the use of wet scrubbers a technically feasible control technology for the startup heater.

(f) Fuel Specifications
The theory behind fuel specifications was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. The Department considers fuel specifications as a technically feasible control technology for the startup heater.

(g) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of NOx emissions. GCPs is considered a technically feasible control option for the startup heater.

Step 2 – Eliminate Technically Infeasible PM Control Options for the Startup Heater
As explained in Section 6.5, fabric filters, cartridge collectors, mechanical separators, ESPs, and wet scrubbers are not feasible to control PM emissions from the startup heater.

Step 3 – Ranking of the Remaining PM Control Technologies for the Startup Heater
The applicant has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls

The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Startup Heater (EU 13) – PM/PM-10/PM-2.5						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
TX-0657	Beaumont Gas to Gasoline Plant	5/16/14	Heater	45 MMBtu/hr	PM/PM-10/PM-2.5 0.81 tpy	GCP & Fuel Type
LA-0272	Dyno Nobel Louisiana Ammonia	3/27/13	Ammonia Startup Heater	61 MMBtu/hr	PM-10 and PM-2.5 0.53 lb/hr (hourly maximum) 0.11 tpy	GCP & Design
IA-0105	Iowa Fertilizer Company	10/26/12	Startup Heater	110.12 MMBtu/hr	PM/PM-10/PM-2.5 0.0024 lb/MMBtu (3-test avg.) 0.01 tpy (rolling 12-month total)	GCP
IN-0172	Ohio Valley Resources	9/25/13	Ammonia Catalyst Startup Heater	106.3 MMBtu/hr	PM 1.9 lb/MMcf (3-hr avg.) PM-10 and PM-2.5 7.6 lb/MMcf (3-hr avg.)	GCP & Design
LA-0244	Sasol N.A., Inc.	11/29/10	Startup Heater	21 MMBtu/hr	0.21 lb/hr (hourly maximum)	None
IN-0180	Midwest Fertilizer Corporation	6/4/14	Startup Heater	92.5 MMBtu/hr	PM 1.9 lb/MMcf (3-hr avg.) PM-10 and PM-2.5 7.6 lb/MMcf (3-hr avg.)	GCP, Design, & Fuel Type
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Startup Heater**	**101 MMBtu/hr**	**PM/PM-10/PM-2.5** **0.0074 lb/MMBtu**	**Limited Use**

RBLC Review

A review of similar units in the RBLC indicates good combustion practices is the principle PM control technology for startup heaters.

Applicant Proposal

The applicant proposes the following as BACT:

(a) PM, PM-10, and PM-2.5 emissions from the operation of the startup heater shall be controlled with limited use of the unit.

(b) PM, PM-10, and PM-2.5 emissions from the startup heater shall not exceed 7.6 lb/MMscf (0.0074 lb/MMBtu).

(c) Operating hours for the startup heater shall not exceed 200 hours per year.

Step 5 – Selection of PM BACT for the Startup Heater
The Department agrees with the applicant that an emission rate achievable with limited use is BACT for the startup heater. PM emissions from the startup heater (EU 13) shall not exceed 0.0074 lb/MMBtu and operating hours will be limited to 200 hours per year. Compliance with the proposed emission limit will be demonstrated by recording total fuel usage and operating hours for the startup heater.

6.6 PM BACT for the Ammonia Tank Flare and Small Flares (EUs 11, 22, and 23)

Step 1 – Identification of PM Control Technology for the Flares
From research, the Department identified the following technologies as available for PM control of the flares:

(a) Flare Work Practice Requirements
Flare work practice requirements can be found in 40 CFR 60.18 (c) and (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 use of proper flare design and good combustion practices are technically feasible control options for the flares.

(b) Process Flaring Minimization Plan
Process flaring minimization plans define the procedures intended to reduce the volume of gas going to the flare without compromising plant operations and safety. Process flaring minimization practices is a technically feasible control option 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 for the KNO facility is not technically feasible because the gases controlled by the flares contain ammonia and are not suitable for use in other operations or as fuel at the plant.

Step 2 – Eliminate Technically Infeasible PM Control Options for the Flares
As explained in Section 6.6, flare gas recovery is not feasible to control PM emissions from the flares.

Step 3 – Ranking of the Remaining PM Control Technologies for the Flares
The following control technologies have been identified and ranked for the control of PM from the flares.

(a) Flare Work Practice Requirements
(b) Process Flaring Minimization Plan

Step 4 – Evaluate the Most Effective Controls

The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA
Ammonia Tank Flare, Plants 4 and 5 Small and Emergency Flares (EUs 11, 22, and 23) – PM/PM-10/PM-2.5

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
LA-0272	Dyno Nobel Louisiana Ammonia	3/27/13	Ammonia Storage Flare	0.25 MMBtu/hr pilot, 14.94 MMBtu/hr vent gas	PM-10 and PM-2.5 0.001 lb/hr (hourly maximum) 0.005 tpy	Work Practice & GCP
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Work Practice & GCP
IN-0172	Ohio Valley Resources	9/25/13	Ammonia Storage Flare	0.13 MMBtu/hr	PM 0.0019 lb/MMBtu (3-hr avg.) PM-10 and PM-2.5 0.0075 lb/MMBtu (3-hr avg.)	FMP & Fuel Type
ID-0017	Southeast Idaho Energy	2/10/09	Ammonia Storage Flare	0.75 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	Smoke-less Flare & GCP
AK-0076	Pt Thomson Production	8/20/12	Combustion Flares	35 MMscf/yr	PM-2.5 0.0264 lb/MMBtu	None
IN-0180	Midwest Fertilizer Corporation	6/4/14	Ammonia Storage Flares	1.5 MMBtu/hr, 4 MMBtu/hr, 4 MMBtu/hr	PM 0.0019 lb/MMBtu (3-hr avg.) PM-10 and PM-2.5 0.0075 lb/MMBtu (3-hr avg.)	FMP & Fuel Type
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Ammonia Tank Flare**	**1.25 MMBtu/hr**	**PM/PM-10/PM-2.5** **0.0074 lb/MMBtu** **(3-hr avg.)** **(SSM venting, 168 hr/yr)**	**Work Practice & FMP**
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Emergency Flare**	**0.4 MMBtu/hr**	**PM/PM-10/PM-2.5** **0.0074 lb/MMBtu** **(3-hr avg.)** **(SSM venting, 168 hr/yr)**	**Work Practice & FMP**
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Small Flare**	**1.25 MMBtu/hr**	**PM/PM-10/PM-2.5** **0.0074 lb/MMBtu** **(3-hr avg.)** **(SSM venting, 168 hr/yr)**	**Work Practice & FMP**

RBLC Review

Most of the RBLC control method entries for flares list flare work practice requirements and good combustion practices as the principle PM control technologies for flares.

Applicant Proposal

The applicant proposes the following as BACT:

(a) Startup, shutdown, and maintenance venting to the ammonia tank flare, small flare, and emergency flare shall not exceed 168 hours each, per 12-consecutive month period.

(b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:

(1) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable; and

(2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other maintenance events.

(c) Flare emissions shall be controlled by use of the following practices:

(1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed five minutes during any two consecutive hours;

(2) Flares shall be operated with a flame present at all times; and

(3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(d) PM emissions from the ammonia tank flare, small flare, and emergency flare shall not exceed 0.0074 lb/MMBtu during normal operation, based on a three-hour average.

Step 5 – Selection of PM BACT for the Ammonia Tank Flare, Small Flare, and Emergency Flare

The Department agrees with the applicant that an emission rate achievable with flare work practice requirements and developing a flare minimization is BACT for the flares. PM emissions from the flares (EUs 11, 22, and 23) shall be controlled through work practices and by minimizing their use, and shall not exceed 0.0074 lb/MMBtu during normal operations. PM emissions from the flares venting shall be limited to no more than 168 hours each per rolling 12-consecutive months.

6.7 PM BACT for the Well Pump and Fire Pump Engine (EUs 65 and 66)

Step 1 – Identification of PM Control Technology for the Pump Engines
Stationary emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60 Subparts IIII and JJJJ, and 40 CFR 63 Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with the applicable emission limitations.

Step 2 – Eliminate Technically Infeasible PM Control Options for the Pump Engines
The only feasible control option for the diesel-fired well pump and gasoline-fired fire pump engines is good combustion practices.

Step 3 – Ranking of the Remaining PM Control Technologies for the Pump Engines
The applicant has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Fire Pump Engine (EU 66) – PM/PM-10/PM-2.5						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
ID-0018	Idaho Power Company	6/25/10	Fire Pump Engine	235 kW	0.2 g/kW-hr	Tier III & GCP
LA-0251	Flopam, Inc.	4/26/11	Fire Pump Engines (2 units)	444 hp (each)	PM-10 0.01 lb/hr, 0.01 tpy, 0.15 g/hp-hr (annual average)	None
LA-0254	Ninemile Point Electric Generating Plant	8/16/11	Emergency Fire Pump	350 hp	PM-10 and PM-2.5 0.15 g/hp-hr (annual average)	GCP & ULSD
IN-0172	Ohio Valley Resources	9/25/13	Diesel-Fired Emergency Water Pump	481bhp	PM/PM-10/PM-2.5 0.15 g/hp-hr (annual average)	GCP
IA-0105	Iowa Fertilizer Company	10/26/12	Fire Pump	235 kW	PM/PM-10/PM-2.5 0.2 g/kW-hr (3 stack test avg.) 0.03 tpy	GCP

OH-0254	Duke Energy Washington County	8/14/13	Fire Pump Engine	400 hp	PM 0.88 lb/hr 0.22 tpy 1 g/hp-hr (annual avg.)	GCP & Fuel Type
IN-0180	Midwest Fertilizer Company	6/4/14	Fire Pump	500 hp	PM/PM-10/PM-2.5 0.15 g/hp-hr (3-hr avg.)	GCP
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Diesel-Fired Well Pump Engine**	**2.7 MMBtu/hr**	**PM/PM-10/PM-2.5** **0.31 lb/MMBtu** **(3-hr avg.)**	**GCP** **& Limited Use**
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Gasoline-Fired Fire Pump Engine**	**2.1 MMBtu/hr**	**PM/PM-10/PM-2.5** **0.1 lb/MMBtu** **(3-hr avg.)**	**Limited Use**

RBLC Review
A review of similar units in the RBLC indicates good combustion practices is the principle PM control technology for both diesel-fired and gasoline-fired pump engines.

Applicant Proposal
The applicant proposes the following as BACT:

(a) PM emissions from the operation of the diesel-fired well pump and gasoline-fired fire water pump shall be controlled with limited use of the units.

(b) PM emissions from the diesel-fired well pump shall not exceed 0.31 lb/MMBtu.

(c) PM emissions from the gasoline-fired fire water pump shall not exceed 0.1 lb/MMBtu.

(d) Operating hours for EUs 65 and 66 shall not exceed 168 hours per year, each.

Step 5 – Selection of PM BACT for the Well Pump and Fire Water Pump Engines
The Department agrees with the applicant that an emission rate achievable with limited use is BACT for the pump engines. PM emissions from the diesel-fired well pump engine (EU 65) and the gasoline-fired fire pump engine (EU 66) shall not exceed 0.31 lb/MMBtu and 0.1 lb/MMBtu, respectively, and operating hours will be limited to 168 hours per year each. Compliance with the proposed emission limit will be demonstrated by recording total fuel usage and operating hours for the pump engines.

6.8 PM BACT for the Urea Granulation A/B and C/D (EUs 35 and 36)

Step 1 – Identification of PM Control Technology for the Urea Granulation
From research, the Department identified the following technologies as available for PM control of the Urea Granulation:

(a) Fabric Filters

The theory behind fabric filters was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Because of the sticky physical properties of the hot urea granule, fabric filters will not be compatible with the Urea Granulation due to bag fouling causing excessive maintenance problems. Therefore use of fabric filters is not considered a technologically feasible control technology for granulation lines.

(b) Wet and Dry Electrostatic Precipitators
The theory behind ESPs was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Because of the physical characteristics of this waste gas stream, the charged particles will become stuck to the walls of the control device. This will reduce collection efficiency and result in excessive maintenance problems. The use of ESPs, therefore, is not a technologically feasible control option.

(c) Wet Scrubbers
The theory behind wet scrubbers was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. The urea granules created in the granulation lines are hygroscopic. They tend to attract and hold water molecules in the air. Wet Scrubbers are considered a technologically feasible control option.

(d) Cyclones
The theory of operation of a cyclone was discussed in detail in the particulate matter BACT for the reformer and will not be repeated here. Granulated urea is created in the granulation unit by spraying a heated liquid into a fluidized bed containing fine granules. The urea coats the particles until they reach the desired diameter. The hot urea granules are sticky until completely cooled. Cyclones rely on particulate matter to fall out of the gas stream when they impact the wall of the control device. Because the granules are sticky, they will collect on the walls of the cyclone instead of falling into the collection hopper. This will cause the unit to foul on a frequent basis. Therefore, a cyclone is not a feasible control technology for this waste gas stream.

Step 2 - Elimination of Technically Infeasible PM Controls for the Urea Granulation
As explained in Section 6.8, fabric filters, wet and dry electrostatic precipitators, and cyclones are not considered technically feasible PM control options for the Urea Granulation.

Step 3 - Ranking of Remaining PM Control Technologies for the Urea Granulation
Wet Scrubbers are the only technically feasible PM control technology for the urea granulation, therefore ranking is not required.

Step 4 - Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in this table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Urea Granulation (EUs 35 and 36) – PM/PM-10/PM-2.5						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
IA-0106	CF Industries Nitrogen, LLC	7/12/13	Urea Granulator	176.46 ton urea/hr (4,235 ton/day)	PM/PM-10/PM-2.5 0.11 lb/ton urea (3 stack test avg.) 85.7 tpy	GCP & Wet Scrubber
IA-0105	Iowa Fertilizer Company	10/26/12	Urea Granulator	1,500 metric tons/day	PM and PM-10 0.1 kg/metric ton (3 stack test avg.) 60.4 tpy PM-2.5 0.025 kg/metric ton (3 stack test avg.) 15.1 tpy	Wet Scrubber
OK-0124	Koch Nitrogen Company	5/1/08	Urea Granulators	1,550 tons urea/day	PM-10 6.6 lb/hr	Wet Scrubber 90% Control
IN-0180	Midwest Fertilizer Corporation	6/4/14	Urea Granulation Unit	1,440 metric tons/day	PM/PM-10/PM-2.5 0.163 lb/ton granules (3-hr avg.)	Wet Scrubber 90% Control
LA-0098	CF Industries Nitrogen, LLC	10/14/94	Urea Granulator	894,250 tpy	PM-10 46.4 lb/hr	Wet Scrubber
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Urea Granulators**	**50 tons urea/hour**	**PM/PM-10/PM-2.5** **0.2 lb/ton urea**	**Wet Scrubber 90% Control**

RBLC Review

A review of similar units in the RBLC indicates wet scrubbers is the principle PM control technology installed on Urea Granulation.

Applicant Proposal

The applicant provided an economic analysis of the installation of high efficiency wet scrubbers on the granulation lines to demonstrate that high efficiency wet scrubbers are not economically feasible on these units. A summary of the analysis is shown below:

Control Alternative	Captured Emissions (tpy)	Emission Reduction (tpy)	Capital Cost ($)	Operating Costs ($/year)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
High Efficiency Wet Scrubbers	35.9	27	$10,000,000	$445,000	$1,389,000	$51,444
Capital Recovery Factor = 0.0944 (7% for a 20 year life cycle)						

The Department calculated the capital recovery factor assuming a 20 year life cycle as indicated in US EPA's, *Stationary Source Control Techniques Document for Fine Particulate Matter (October 1998).*

The applicant proposes the following as BACT:

(a) PM emissions from the operation of granulation lines shall be controlled with the use of wet scrubbers.

(b) PM, PM-10, and PM-2.5 emissions from the granulation lines shall not exceed 0.2 lb/ton of urea produced.

(c) Compliance with the proposed emission limit will be demonstrated by conducting an initial stack test to obtain an emission rate.

Step 5 – Selection of PM BACT for the Urea Granulation
The Department agrees with the applicant that an emission rate achievable with wet scrubbers is BACT for the Urea Granulation. PM emissions from each of the Urea Granulation (EUs 35 and 36) shall be controlled by use of wet scrubbers and shall not exceed 0.2 lb/ton urea produced.

6.9 PM BACT for the Urea Ship Loading (EU 47)

Step 1 – Identification of PM Control Technology for the Urea Ship Loading
The Department did not identify any sources with controls on urea ship loading operations. Fabric filters, wet scrubbers, ESPs, and cyclones are available control options for particulate matter emissions and will be considered in this analysis.

Step 2 - Elimination of Technically Infeasible PM Controls for the Urea Ship Loading
Fabric filters, wet scrubbers, ESPs, and cyclones are infeasible control technologies for ship loading operations due to the variability in the size and orientation of ship holds. Further, there is no practical means to capture emissions during loading in order to direct them to control devices. The manufacturing process at the facility is designed to minimize the presence of dust on the urea product.

Step 3 - Ranking of Remaining PM Control Technologies for the Urea Ship Loading
No add-on control technology has been determined to be feasible for control of PM emissions from ship loading. As a result, no add-on control technology is evaluated for this source.

Step 4 - Evaluate the Most Effective Controls
The uncontrolled PM and PM-10 emission factors provided in the application are from the EPA Factor Information Retrieval (FIRE) database. The uncontrolled PM-2.5 emission factor provided in the application is derived based on the EPA Particulate Calculator for the Standard Classification Code 30104007. The applicant proposes the following PM, PM-10, and PM-2.5 emission factors, based on a combination of manufacturing design and loading techniques:

Particulate Matter Emission Factors with Controls				
Pollutant	Uncontrolled Emission Factor	UF-85 and Product Coolers on Granulation Lines (50% Control)	Loading into Partial Enclosure (50% Control)	Use of Telescoping Chute (75% Control)
PM	0.02 lb/ton of urea	0.01 lb/ton of urea	0.005 lb/ton of urea	**0.00125 lb/ton of urea**
PM-10	0.017 lb/ton of urea	0.0085 lb/ton of urea	0.00425 lb/ton of urea	**0.00106 lb/ton of urea**
PM-2.5	0.006 lb/ton of urea	0.003 lb/ton of urea	0.006 lb/ton of urea	**0.000375 lb/ton of urea**

UF-85 and Product Coolers on Granulation Lines (50% Control)
The applicant intends to use urea formaldehyde concentrate (UF-85) as a hardening agent in the urea manufacturing process to maintain the integrity of urea granules during handling and ship loading. In addition, product coolers were installed on all four of KNO's granulated urea process lines to provide additional cooling, allowing the granules to harden better before being placed into storage. Cooling also reduces the potential of crystal formation on the granules due to moisture in the air which causes them to clump and then break apart as they are handled.

Loading into Partially Enclosed Ship Holds (50% Control)
The applicant proposes that particulate matter emissions generated during loading operations can be controlled by loading into partially enclosed ship holds. They quantified the reduction based on guidance provided by the Texas Commission on Environmental Quality[2] that suggests 90% control of PM can be assumed for full enclosures. This efficiency is reduced to 50% control to recognize that ship holds are not full enclosures.

Drop Height Reduction using Telescoping Chute (75% Control)
The applicant intends to further reduce the release of particulate emissions due to ship loading by minimizing the drop height of loading operations. The document "*Stationary Source Control Techniques Documents for Fine Particulate Matter*"[3] contains information on control techniques for control of fugitive particulate matter emissions, with suggested control efficiencies expected from the various techniques. Table 6-1 of this document provides estimated control efficiencies for various drop height reduction techniques. This table indicates that telescoping chutes are estimated to provide a 75% reduction in particulate matter emissions.

Using the adjusted ship loading emission factors that result from manufacturing techniques, loading into enclosed holds, and use of a telescoping chute; the following table lists the proposed particulate matter BACT limits:

[2] "Rock Crushing Plants", Texas Commission on Environmental Quality, Table 7
[3] Stationary Source Control Techniques Document for Fine Particulate Matter, Prepared by EC/R Incorporated for Air Quality Strategies and Standards Division, US EPA, October 1998.

Proposed BACT Limit Urea Ship Loading(EU 47) – PM/PM-10/PM-2.5						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
OK-0124	Koch Nitrogen Company	5/1/08	Solids Handling and Loading	1,550 tons/day	PM-10 90% Control	Enclosure of Handling Operations, Telescoping Chutes on Loading, and Conditioning Agent to Reduce Brittleness
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Urea Ship Loading**	**1,000 tons urea/hour**	**PM** **0.00125 lb/ tons urea** **PM-10** **0.00106 lb/ ton urea** **PM-2.5** **0.000375 lb/ ton urea**	Use of UF-85 (Hardening Agent), Product Coolers on Granulation Urea Process Lines Loading into Partial Enclosure Telescoping Chute

RBLC Review
A review of RBLC yields no other sources with controls on urea ship loading operations.

Applicant Proposal
The applicant proposes the following as BACT:

(a) PM emissions from ship loading operations shall be controlled by hardening the urea granules with UF-85 and product coolers, by minimizing drop heights with a telescoping chute, and by loading into a partially enclosed ship hold.

(b) PM emissions from ship loading operations shall not exceed 0.00125 lb/tons of urea.

(c) PM-10 emissions from ship loading operations shall not exceed 0.00106 lb/tons of urea.

(d) PM-2.5 emissions from ship loading operations shall not exceed 0.000375 lb/tons of urea.

Step 5 – Selection of PM BACT for the Urea Ship Loading
The Department agrees with the applicant that an emission rate achievable with UF-85, product coolers, a telescoping chute, and loading partially enclosed ship holds is BACT for the urea ship loading. PM, PM-10, and PM-2.5 emissions from urea ship loading activities (EU 47) shall not exceed 0.00125, 0.00106, and 0.000375 lb/tons of urea produced.

6.10 PM BACT for the Urea Handling Units (EUs 47B through 47D)

Step 1 – Identification of PM Control Technology for the Urea Handling Units
From research, the Department identified the following technologies as available for PM control of the urea material handling units:

(a) Fabric Filters
The theory of operation of fabric filters was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Fabric filters are a feasible control technology for the urea handling units.

(b) High Efficiency Particle Air Filters (HEPA)
HEPA filters are high efficiency filters that must satisfy efficiency standards set forth by the United States Department of Energy. Certain HEPA filters are capable of achieving control efficiencies greater than 99.9% (EPA-452/F-03-023). HEPA filters are a feasible control technology for the urea handling units.

(c) Cartridge Collectors
The theory of operation of cartridge collectors was discussed in detail in the particulate matter BACT for the turbines and will not be repeated here. Cartridge filters are a feasible control technology for the urea handling units.

(d) Water Application
Water application involves spraying water in order to suppress particulate matter emissions. Spraying water would adversely affect facility operations and is, therefore, not considered technologically feasible.

Step 2 - Elimination of Technically Infeasible PM Controls for the Urea Handling Units
As explained in Section 6.10, water application is not considered as a technically feasible control option for particulate matter reduction of the urea handling units.

Step 3 - Ranking of Remaining PM Control Technologies for the Urea Handling Units
The following control technologies have been identified and ranked for control of PM from the urea handling units.

(a)	Fabric Filters	(> 99% Control)
(b)	HEPA Filters	(> 99% Control)
(c)	Cartridge Collectors	(> 99% Control)

Step 4 - Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in this table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA
Urea Handling Units (EUs 47B through 47D) – PM/PM-10/PM-2.5

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
OK-0124	Koch Nitrogen Company	5/1/08	Solids Handling and Loading	1,550 tons/day	PM-10 90% Control	Enclosure of Handling Operations, Telescoping Chutes on Loading, and Conditioning Agent to Reduce Brittleness
IA-0105	Iowa Fertilizer Company	10/26/12	Granulated Urea Transfer	1,500 metric tons/day	PM and PM-10 0.005 grains/dscf (3 stack test avg.), PM-2.5 0.0013 grains/dscf (3 stack test avg.)	Bin Vent Filter
IN-0180	Midwest Fertilizer Corporation	6/4/14	Urea Junction Operation	1,440 metric tons/day	PM/PM-10/PM-2.5 0.21 lb/hour (3-hr avg.)	Fabric Filter Dust Collector
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Urea Handling Units**	**100 tons/hour**	**PM/PM-10/PM-2.5** **0.005 grains/dscf (3 stack test avg.)**	**Fully Enclosed Conveyors & Fabric Filter**

RBLC Review
A review of similar units in the RBLC indicates fabric and bin filters are the principle PM control technologies installed on urea handling units.

Applicant Proposal
The applicant proposes the following as BACT:

(a) PM emissions from the operation of the urea material handling units shall be controlled with the use of fabric filters.

(b) PM, PM-10, and PM-2.5 emissions from the urea handling units shall not exceed 0.005 grains/dscf.

Step 5 – Selection of PM BACT for the Urea Material Handling Units (47B through 47D)
The Department agrees with the applicant that an emission rate achievable with fully enclosed conveyors and fabric filters is BACT for the urea handling units. PM emissions from each of the urea handling units (EUs 47B through 47D) shall be controlled by use of wet scrubbers and shall not exceed 0.005 grains/dscf.

6.11 PM BACT for the Two Cell Cross-Flow Cooling Tower (EU 40)

Step 1 – Identification of PM Control Technology for the Cooling Tower
Emissions from cooling towers are generally controlled by a drift elimination system.

(a) High Efficiency Drift Eliminators
Cooling towers are a source of particulate matter emissions from the small amount of water mist that is entrained with the cooling air as “drift”. The cooling water contains small amounts of dissolved solids which become particulate matter emissions once the water mist evaporates. To

reduce the drift from cooling towers, drift eliminators are typically incorporated into the tower design to remove as many droplets as practical from the air stream before exiting the tower.

Drift eliminators contain packing which is used to limit the amount of particulate matter which becomes airborne during the cooling process. As mist passes through the packing, the particles in the air contact and adhere to the surface of the packing. As condensed water flows down this packing, these particles are removed. The use of a drift elimination system is technically feasible control option for the cooling tower.

(b) Dissolved Solids Management
A cooling tower is a device intended to remove heat from a process through the evaporation of water. The minerals contained in the vaporized water remain in the recirculated cooling water and form scale or increase the total dissolved solids. Operators remove water from the system (blow down) and replace it with makeup water to maintain a desired total dissolved solids concentration and a constant volume of recirculated water. The blow down process is automated and the system normally contains a conductivity sensor and a solenoid valve to automatically remove solids from the system. The proper management of the total dissolved solids concentration of the recirculation water is a technologically feasible control method for the cooling tower.

(c) Dry Cooling
Dry cooling systems do not use water as a cooling medium and are categorized as indirect. Dry cooling uses indirect air to cool the water. The main advantage of a dry cooling system is the reduction in water consumption. Dry cooling is eliminated from further consideration because the technology is expensive and only used in areas of extreme water shortage.

Step 2 - Elimination of Technically Infeasible PM Controls for the Cooling Tower
As explained in Section 6.11, dry cooling systems is eliminated from further review, due to its expense and because water shortage is not a concern at KNO.

Step 3 - Ranking of Remaining PM Control Technologies for the Cooling Tower
The following control technologies have been identified and ranked for control of PM from the cooling tower.

(a) Drift Eliminators
(b) Dissolved Solids Management

Step 4 - Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in this table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA
Cooling Tower (EU 40) – PM/PM-10/PM-2.5

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
LA-0248	Nucor, Direct Reduction Plant	1/27/11	Cooling Towers	26,857 GPM (two units) 17,611 GPM (one unit)	0.0005% Drift 1,000 mg/L TDS	Drift Eliminators
IA-0106	CF Industries, Port Neal	7/12/13	16 Cell Draft Cooling Tower	322,000 GPM	0.005% Drift 2,000 mg/L TDS	High Efficiency Drift Eliminators
IN-0180	Midwest Fertilizer Corporation	6/4/14	10 Cell Cooling Tower	147,937 GPM	0.0005% Drift 2,000 mg/L TDS	High Efficiency Drift Eliminators
IN-0180	Midwest Fertilizer Corporation	6/4/14	6 Cell Cooling Tower	88,762 GPM	0.0005% Drift 2,000 mg/L TDS	High Efficiency Drift Eliminators
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**2 Cell Cross-Flow Cooling Tower**	**15,000 GPM**	**0.002% Drift**	**Drift Eliminators**

RBLC Review
A review of similar units in the RBLC indicates drift eliminators is the principle PM control technology installed on cooling towers. Unlike counter-flow towers, cross-flow type towers (like the Class 600 cooling tower located at KNO) cannot achieve a 0.0005% drift rate. Tower configuration and gravity has an impact on drift rate. The drift eliminators in a cross-flow tower must strip the water out and drain it through the height of the pack until it gets to a drain board and shed the water back onto the fill. The fill velocity in a cross-flow tower is much more non-uniform than on a counter-flow tower. The velocity is much higher at the top of the fill pack than at the bottom and the drift is more likely to be pulled out of the drift eliminators at those locations. In a counter-flow tower the velocity is more uniform and the water does not load up in the eliminators since it can discharge the water back into the fill at any location. The highest drift rate a cross-flow tower, such as the one at KNO can achieve, is 0.002%.

Applicant Proposal
The applicant proposes the following as BACT:

(a) PM, PM-10, and PM-2.5 emissions from the cooling tower shall be controlled by drift eliminators designed with a drift loss rate of less than 0.002%.

Step 5 – Selection of PM BACT for the Cooling Tower
The Department agrees with the applicant that an emission rate achievable with drift eliminators is BACT for the cooling tower. PM emissions from the cooling tower (EU 40) shall be controlled by use of drift eliminators with a drift loss rate of less than 0.002%.

APPENDIX C: BACT ANALYSIS GREEN HOUSE GASES

1.0 BACT Determination for Greenhouse Gases

The Department reviewed the RACT/BACT/LAER Clearinghouse (RBLC) for all PSD applicable emission units as recently as September 5, 2014, and found that between 2001 and 2014, 63 determinations were made for carbon dioxide (CO_2). Table C-1, provides a summary of the RBLC for July 2001 through September 2014.

The turbines planned for use at the stationary source are each rated at 37.6 MMBtu/hr. The Department found no determination for turbines of this size (<25 MW), but found that larger turbines did not have additional controls beyond the use of a DLN turbine and good combustion practices.

The Department reviewed Agrium's BACT analysis and made a determination based on internet research, the BACT analysis information provided by Agrium in their October 24, 2013 application, and the EPA RBLC.

CO_2 emissions account for 99% of the total CO_2e emissions of the stationary source. Controls for CO_2 emissions also minimize methane (CH_4) and nitrous oxide (N_2O) emissions; therefore, the BACT analysis was prepared for CO_2 only.

This analysis focuses on the emissions of CO_2 only. While other greenhouse gases (GHGs), such as methane and N_2O are present in trace quantities, there are no known add-on control technologies for these pollutants coming from combustion sources. To the extent measures are identified that reduce fuel use and thereby CO_2, the other GHGs will be reduced accordingly. Therefore, CO_2 serves as a useful surrogate for other GHGs in this regard.

Table C-1: RBLC Determinations for Carbon Dioxide as of September 5, 2014

Description of BACT	Combustion Turbines		Primary Reformer Furnaces	Diesel IC Engines		Diesel Heaters and Boilers	Startup Heaters	Flares	Urea Lines	CO_2 Vents
	MW < 25	MW > 25		hp > 500	hp < 500					
Good Combustion Practices		2	7	7	6	8	4	2		
Dry Low NOx Burners with Inlet Air Heating	2									
Proper Design and Good Combustion				1		2	1			
Tuning, Optimization, Instrumentation and Controls, Insulation, and Turbulent Flow						1				
Use of natural gas						3	3	3		
Selective Catalytic Reduction Controls						1				

Description of BACT	Combustion Turbines		Primary Reformer Furnaces	Diesel IC Engines		Diesel Heaters and Boilers	Startup Heaters	Flares	Urea Lines	CO_2 Vents
	MW < 25	MW > 25		hp > 500	hp < 500					
Flare Minimization Plan								6		
Maintain flame when gas is routed to flare								2		
Good Operational Practice									5	5
Use of Tier 1 engines				1						
Total	**2**	**2**	**7**	**9**	**6**	**15**	**8**	**13**	**5**	**5**

1.1 GHG BACT for the Turbines (EUs 55 through 59)

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, or product of combustion in the case of distillate fuel oil.

Step 1 – Identification of CO_2 Control Technologies for the Turbines

From research, the Department identified the following technologies as available for CO_2e control for the turbines:

(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 that improves the efficiency of the operation.

(1) Simple Cycle (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) Gas Turbine with Waste Heat Recovery and Traditional Combined Cycle
In this configuration, waste heat recovery units are added to the exhausts of the turbines, and recover previously unused energy to drive a steam turbine generator (STG). This leads to a more energy efficient operation because the additional power produced by the STG 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) 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 900 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 Storage (CCS)
The EPA Guidance classifies CCS as "an add-on pollution control technology that is 'available' for facilities emitting CO_2 in large amounts." Agrium 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 United States 2012 Carbon Utilization and Storage Atlas indicates that there is an extensive saline aquifer in the Cook Inlet Basin with a high CO_2 sequestration potential. However, CCS technologies for the ammonia production industry are still considered to be in the research phase. Therefore, the Department considers CCS as a technically infeasible control option as is eliminated from further consideration for GHG BACT.

(c) Alternative fuels
Natural gas are the predominant fuels planned to be used at the facility. Given the equipment planned to be installed in the facility, the use of other fuels would fundamentally redefine the project, and is therefore not considered as an option in the BACT analysis.

Step 2 – Eliminate Technically Infeasible Control Options

The following control options have been determined to be technically infeasible:

1) **Organic Rankine Cycle –** ORC would require additional equipment due to the complexities of the operations, thereby increasing the physical size and footprint of the facility. The increased fuel consumption during cold temperatures increases the gas turbine heat rates and significantly offsets CO_2 reduction benefits.

2) **Carbon Capture and Storage –** CCS requires additional infrastructure for the capture, transportation, and storage of carbon dioxide. Various post-combustion capture technologies are available, but are currently not demonstrated in practice for combustion turbines. At present, there are no large-scale applications of CCS technology anywhere in the world. In addition, there are no proven safe storage sites for KNO Facility, and in the Cook Inlet Basin. An appropriate design for a CO_2 pipeline would also be required if the storage reservoir is at the KNO Facility.

3) **Alternative Fuels –** As discussed in Section 1.1, alternative fuels is not considered a feasible control technology for GHGs and is eliminated from further review.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness.

The following control technologies have been identified and ranked for control of CO_2 from the turbines.

(a)	Simple Cycle with Waste Heat Recovery Unit	(10% Control)
(b)	Simple Cycle	(Baseline)

Step 4 – Evaluate More Effective Controls
The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units (combustion turbines rated at less than 25 MW). All data in this table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Alaska

issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Solar Combustion Turbines (EUs 55 through 59) – CO_2e BACT						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
AK-0076	Point Thomson Production Facility	5/30/13	Four Gas Turbines	7,520 kW (each)	89,336 tpy (2 gas-fired turbines) 95,942 tpy (2 dual fuel-fired turbines)	LNB & Inlet Air Heating
IA-0107	Marshalltown Generating Station	5/16/14	Two combustion Turbines	2,258 MMBtu/hr	951 lb/MW-hr 1,318,647 tpy	None
TX-0636	Houston Central Gas Plant	1/7/14	Two Combustion Turbines	15,000 hp	65,097 tpy	None
TX-0612	Thomas C. Ferguson Power Plant	9/25/13	Combined Cycle Turbine Generator	1,746 MMBtu/hr	908,957.6 lb/hr (30-day rolling average)	GCP
PA-0296	Berks Hollow Energy Association	4/17/14	Turbine, Combined Cycle #1 and #2	3,046 MMBtu/hr	1,000 lb/MW-hr 1,380,899 tpy	None
IN-0180	Midwest Fertilizer Company	8/13/14	Two Natural Gas Fired Combustion Turbines	283 MMBtu/hr (each)	116.89 lb/MMBtu (3-hr avg.) 12,666 Btu/kW-hr	GCP & Proper Design
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Five Gas Combustion Turbines**	**37.6 MMBtu/hr (each)**	**59.61 tons/MMcf (3-hr avg.) 91,500 tpy (combined)**	**Simple Cycle with Waste Heat Recovery Units**

RBLC Review
A review of similar units in the RBLC indicates greenhouse gas emissions are controlled by good combustion practices and design features to maximize the efficiency of the turbines. Efficient turbines will require less fuel which reduces greenhouse gas emissions. 59.61 tons CO_2e per MMcf is equivalent to the GHG BACT limits for: Ohio Valley's reformer heater in the 9/25/13 PSD permit issued by the State of Indiana, Iowa Fertilizer Company's PSD permit issued on 10/26/12, and Magnolia Nitrogen's PSD permit issued on April 21, 2014.

Applicant Proposal
The applicant proposes the following as BACT:

(a) Energy will be recovered through use of waste heat boilers.

(b) CO_2e emissions from the turbines shall not exceed 59.61 tons/MMcf of natural gas combusted based on a three-hour average.

(c) CO_2e emissions from the turbines shall not exceed 91,500 tpy combined.

Step 5 – Establish BACT
The Department agrees with the applicant that an emission rate achievable with simple-cycle turbines with waste heat recover units is BACT for the turbines. CO_2e emissions for the natural gas-fired combustion turbines (EUs 55 through 59) shall be controlled by use of simple cycle turbines with waste heat recovery units and shall not exceed 59.61 tons/MMcf of natural gas burned or 91,500 tpy combined.

1.2 CO_2e BACT for the Primary Reformer (EU 12)

Step 1 – Identification of CO_2 Control Technology for the Primary Reformer
From research, the Department identified the following technologies as available for CO_2e control of reformer furnaces:

(a) Cogeneration/Combined Heat and Power (CHP)
The reformer furnace uses natural gas as a fuel to produce hydrogen syngas. The functionality and design of the reformer is such that a CHP configuration cannot be applied to the emission unit. Therefore, the Department considers CHP a technically infeasible control technology for the primary reformer.

(b) Carbon Capture and Storage
The theory of CCS was discussed in detail in the CO_2e BACT for the turbines and will not be repeated here. It was determined that CCS is not a technically feasible control technology for the entire source and has been eliminated from further consideration for GHG BACT.

(c) Energy Efficient Design
The reformer utilizes several energy efficient design mechanisms including:
- (1) Combustion Control Optimization
- (2) Tuning
- (3) Instrumentation and Controls
- (4) Air Pre-Heaters
- (5) Turbulators

(d) Good Combustion Practices
The theory of GCP was discussed in detail in the NOx BACT for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of CO_2. Therefore good combustion practices is a feasible control option for the primary reformer.

Step 2 – Eliminate Technically Infeasible CO_2 Control Options for the Primary Reformer
As explained in Section 1.2, CHP and CCS are technically infeasible CO_2 control technologies for the primary reformer.

Step 3 – Ranking of the Remaining CO_2 Control Technologies for the Primary Reformer
The applicant has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls

The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Primary Reformer (EU 12) – CO_2e BACT						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
IA-0105	Iowa Fertilizer Company	10/26/12	Primary Reformer	1,152.6 MMBtu/hr	117 lb/MMBtu (rolling 30-day avg.) 596,905 tpy	GCP
IA-0106	CF Industries Nitrogen, LLC	7/18/13	Primary Reformer	1062.6 MMBtu/hr	117 lb/MMBtu (rolling 30-day avg.) 545,674 tpy	GCP & Fuel Type
IN-0172	Ohio Valley Resources	7/17/14	Primary Reformer	1,006.4 MMBtu/hr	59.61 tons/MMcf (3-hr avg.) 515,246 tpy	GCP & Design
IN-0179	Ohio Valley Resources	8/13/14	Primary Reformer	1,006.4 MMBtu/hr	59.61 tons/MMcf (3-hr avg.) 515,246 tpy	GCP & Design
IN-0180	Midwest Fertilizer Corporation	6/4/14	Reformer Furnace	950.64 MMBtu/hr	59.61 tons/MMcf (3-hr avg.) 486,675 tpy (monthly avg.)	GCP & Design
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Primary Reformer**	**1,350 MMBtu/hr**	**59.61 tons/MMcf (3-hr avg.) 700,000 tpy**	**None**

RBLC Review

Most of the RBLC control method entries for reformer furnaces list the use of good combustion practices and energy efficient design as BACT for primary reformers. Because the primary reformer at KNO is an existing unit, it would need to be retrofitted with replacement burners to achieve the maximum CO_2 control. 59.61 tons CO_2e per MMcf is equivalent to the GHG BACT limits for: Ohio Valley's reformer heater in the 9/25/13 PSD permit issued by the State of Indiana, Iowa Fertilizer Company's PSD permit issued on 10/26/12, and Magnolia Nitrogen's PSD permit issued on April 21, 2014.

Applicant Proposal

The applicant proposes the following as BACT:

(a) CO_2e emissions from the primary reformer shall not exceed 59.61 tons/MMcf of natural gas combusted, based on a three-hour average.

(b) The primary reformer furnace shall be equipped with the following energy efficiency features: air inlet controls and flue gas heat recovery to pre-heat inlet fuel, inlet process air, and inlet steam flows.

(c) CO_2e emissions from the primary reformer shall not exceed 700,000 tons per twelve consecutive month period with compliance determined at the end of each month.

(d) Compliance will be demonstrated through the use of 40 CFR Part 98 emission factors.

Step 5 – Selection of CO_2 BACT for the Primary Reformer
The Department agrees with the applicant that an emission rate achievable with no controls is BACT for the primary reformer. CO_2e emissions from the primary reformer (EU 12) shall not exceed 59.61 tons/MMcf based on a 3-hour average or 700,000 tons per twelve consecutive month period with compliance determined at the end of each month.

1.3 CO_2 BACT for the Package Boilers (EUs 44, 48, and 49)

Step 1 – Identification of CO_2 Control Technology for the Package Boilers
From research, the Department identified the following technologies as available for CO_2 control for three package boilers:

(a) Cogeneration/Combined Heat and Power
CHP involves the production of useable heat and electricity from a single source. The use of CHP results in significant energy gains. Significant reductions in GHG emissions are achieved by recovering energy which would otherwise go to waste. However, the package boilers are used to provide process steam to the plant. Significant process modifications would be required to convert the Package Boilers to CHP. The plant already utilizes Solar Turbines to generate electricity for the plant. Therefore, the Department considers CHP a technically infeasible control technology for the package boilers.

(b) Carbon Capture and Storage
The theory of CCS was discussed in detail in the CO_2 BACT for the turbines and will not be repeated here. It was determined that CCS is not a technically feasible control technology for the entire source and has been eliminated from further consideration for GHG BACT.

(c) Energy Efficient Design
Energy efficient designs can reduce the natural gas required to produce the necessary amount of steam. Therefore emissions of GHGs are reduced. Energy efficient design elements for boilers include combustion control optimization, tuning, instrumentation and controls, economizer, blowdown heat recovery, and condensate return system. An energy efficient design with combustion controls is a technically feasible control option for the package boilers.

(d) Good Combustion Practices
The theory of GCP was discussed in detail in the NOx BACT for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of CO_2. Therefore, good combustion practices is a feasible control option for the package boilers.

Step 2 – Eliminate Technically Infeasible CO_2 Control Options for the Package Boilers
As explained in Section 1.3, cogeneration/combined heat and power and carbon capture and storage are not feasible technologies to control CO_2 emissions from the package boilers.

Step 3 – Ranking of the Remaining CO_2 Control Technologies for the Package Boilers
The applicant has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Package Boilers (EUs 44, 48, and 49) – CO_2e BACT						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
LA-0254	Ninemile Point Electric Generating Plant	12/12/11	Auxiliary Boiler	338 MMBtu/hr	117 lb/MMBtu	GCP
IA-0106	CF Industries Nitrogen, LLC	7/18/13	Boilers	456 MMBtu/hr	117 lb/MMBtu (3 stack test avg.), 234,168 tpy (rolling 12-month total)	GCP & Fuel Type
IA-0105	Iowa Fertilizer Company	8/13/13	Auxiliary Boiler	472.4 MMBtu/hr	117 lb/MMBtu (rolling 30-day avg.), 51,748 tpy	GCP
IA-0107	Marshalltown Generating Station	5/16/14	Auxiliary Boiler	60.1 MMBtu/hr	17,313 tpy (12-month rolling total)	Fuel Limit
IN-0172	Ohio Valley Resources	9/25/13	Natural Gas-Fired Boilers	218 MMBtu/hr	59.61 tons/MMcf (3-hr avg.)	GCP & Design
FL-0330	Port Dolphin Energy LLC	10/29/13	Four Boilers	278 MMBtu/hr (each)	117 lb/MMBtu (8-hr rolling average)	Design
TX-0629	BASF Total Petrochemicals	9/25/13	Steam Package Boilers	425.4 MMBtu/hr	420,095 tpy (12-month rolling avg.)	SCR
IN-0166	Indiana Gasification, LLC	11/15/13	Two Auxiliary Boilers	408 MMBtu/hr (each)	81% Thermal Efficiency (HHV) 88,167 tpy	Design & Fuel Type
IN-0180	Midwest Fertilizer Corporation	6/4/14	Three Auxiliary Boilers	218.6 MMBtu/hr (each)	59.61 ton/MMcf (3-hr avg.)	GCP & Design
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Package Boilers**	**243 MMBtu/hr (each)**	**59.61 tons/MMcf (3-hr avg.), 376,500 tpy (combined)**	**None**

RBLC Review
A review of similar units in the RBLC indicates greenhouse gas emissions are controlled by good combustion practices and design features to maximize the efficiency or the boiler. Efficient boilers will require less fuel which reduces greenhouse gas emissions. All of the entries use 117 lb/MMBtu for CO_2 emissions. This is equivalent to 59.61 ton CO_2/MMcf. 59.61 tons CO_2e per MMcf is equivalent to the GHG BACT limits for: Ohio Valley's reformer heater in the 9/25/13 PSD permit issued by the State of Indiana, Iowa Fertilizer Company's PSD permit issued on 10/26/12, and Magnolia Nitrogen's PSD permit issued on April 21, 2014.

Applicant Proposal
The applicant proposes the following as BACT:

(a) Each of the package boilers shall be equipped with the following energy efficient design features: air inlet controls, heat recovery, and condensate recovery.

(b) CO_2e emissions from the package boilers shall not exceed 59.31 tons/MMcf of natural gas combusted based on a three-hour average.

(c) CO_2e emissions from the package boilers shall not exceed 376,500 tons per 12-consecutive month period with compliance determined at the end of each month.

Step 5 – Selection of CO_2e BACT for the Package Boilers
The Department agrees with the applicant that an emission rate achievable with no controls is BACT for the package boilers (EUs 44, 48, and 49). CO_2e emissions from the package boilers shall not exceed 59.61 tons/MMcf of natural gas combusted or 376,500 tpy (combined).

1.4 CO_2 BACT for the Waste Heat Boilers (EUs 50 through 54)

Step 1 – Identification of CO_2 Control Technology for the Waste Heat Boilers
From research, the Department identified the following technologies as available for CO_2 control for five waste heat boilers:

(a) Cogeneration/Combined Heat and Power
The theory of CHP was discussed in detail in the CO_2 BACT for the package boilers and will not be repeated here. The waste heat boilers are used to recovery energy from the solar turbines to provide process steam to the plant. In combination with the turbines the waste heat boilers are considered to be CHP units and therefore a technologically feasible control technology for CO_2.

(b) Carbon Capture and Storage
The theory of CCS was discussed in detail in the CO_2 BACT for the turbines and will not be repeated here. It was determined that CCS is not a technically feasible control technology for the entire source and has been eliminated from further consideration for GHG BACT.

(c) Energy Efficient Design

The theory behind energy efficient design was discussed in detail in the CO_2 BACT for the package boilers and will not be repeated here. An energy efficient design with combustion controls is a technically feasible control option for the package boilers.

(d) Good Combustion Practices

The theory of GCP was discussed in detail in the NOx BACT for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of CO_2. Therefore, good combustion practices is a feasible control option for the waste heat boilers.

Step 2 – Eliminate Technically Infeasible CO_2 Control Options for the Waste Heat Boilers

As explained in Section 1.4, carbon capture and storage is not a feasible technology to control CO_2 emissions from the waste heat boilers.

Step 3 – Ranking of the Remaining CO_2 Control Technologies for the Waste Heat boilers

The applicant has accepted all feasible control options. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls

The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Waste Heat Boilers (EUs 50 through 54) – CO_2e BACT						
RBLC ID	**Facility**	**Issued Date**	**Process Description**	**Capacity**	**Limitation**	**Control Method**
LA-0254	Ninemile Point Electric Generating Plant	12/12/11	Auxiliary Boiler	338 MMBtu/hr	117 lb/MMBtu	GCP
IA-0106	CF Industries Nitrogen, LLC	7/18/13	Boilers	456 MMBtu/hr	117 lb/MMBtu (3 stack test avg.), 234,168 tpy (rolling 12-month total)	GCP & Fuel Type
IA-0105	Iowa Fertilizer Company	8/13/13	Auxiliary Boiler	472.4 MMBtu/hr	117 lb/MMBtu (rolling 30-day avg.), 51,748 tpy	GCP
IA-0107	Marshalltown Generating Station	5/16/14	Auxiliary Boiler	60.1 MMBtu/hr	17,313 tpy (12-month rolling total)	Fuel Limit
IN-0172	Ohio Valley Resources	9/25/13	Natural Gas-Fired Boilers	218 MMBtu/hr	59.61 tons/MMcf (3-hr avg.)	GCP & Design
FL-0330	Port Dolphin Energy LLC	10/29/13	Four Boilers	278 MMBtu/hr (each)	117 lb/MMBtu (8-hr rolling average)	Design

TX-0629	BASF Total Petrochemicals	9/25/13	Steam Package Boilers	425.4 MMBtu/hr	420,095 tpy (12-month rolling avg.)	SCR
IN-0166	Indiana Gasification, LLC	11/15/13	Two Auxiliary Boilers	408 MMBtu/hr (each)	81% Thermal Efficiency (HHV) 88,167 tpy	Design & Fuel Type
IN-0180	Midwest Fertilizer Corporation	6/4/14	Three Auxiliary Boilers	218.6 MMBtu/hr (each)	59.61 ton/MMcf (3-hr avg.)	GCP & Design
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Waste Heat Boilers**	**50 MMBtu/hr (each)**	**59.61 tons/MMcf (3-hr avg.) 131,405 tpy (combined)**	**None**

RBLC Review
A review of similar units in the RBLC indicates greenhouse gas emissions are controlled by good combustion practices and design features to maximize the efficiency or the boiler. Efficient boilers will require less fuel which reduces greenhouse gas emissions. All of the entries use 117 lb/MMBtu for CO_2 emissions. This is equivalent to 59.61 ton CO_2/MMcf. 59.61 tons CO_2e per MMcf is equivalent to the GHG BACT limits for: Ohio Valley's reformer heater in the 9/25/13 PSD permit issued by the State of Indiana, Iowa Fertilizer Company's PSD permit issued on 10/26/12, and Magnolia Nitrogen's PSD permit issued on April 21, 2014.

Applicant Proposal
The applicant proposes the following as BACT:

(a) CO_2e emissions from the waste heat boilers shall not exceed 59.61 tons/MMcf of natural gas combusted, based on a three-hour average.

(b) CO_2e emissions from the waste heat boilers shall not exceed 131,405 tons per 12-consecutive month period with compliance determined at the end of each month.

Step 5 – Selection of CO_2 BACT for the Waste Heat Boilers
The Department agrees with the applicant that an emission rate achievable with no controls is BACT for the waste heat boilers. CO_2e emissions from the boilers (EUs 50 through 54) shall not exceed 59.61 tons/MMcf of natural gas combusted or 131,405 tpy (combined).

1.5 CO_2 BACT for the Startup Heater (EU 13)

Step 1 – Identification of CO_2 Control Technology for the Startup Heater
From research, the Department identified the following technologies as available for CO_2 control of startup heaters:

(a) Carbon Capture and Storage
The theory of CCS was discussed in detail in the CO_2e BACT for the turbines and will not be repeated here. It was determined that CCS is not a technically feasible control technology for the entire source and has been eliminated from further consideration for GHG BACT.

(b) Energy Efficient Design
The theory behind energy efficient design was discussed in detail in the CO_2 BACT for the package boilers and will not be repeated here. An energy efficient design with combustion controls is a technically feasible control option for the startup heater

(c) Low Carbon Fuel
The primary fuel can be selected to minimize the carbon content which reduces the carbon available for conversion to CO_2. Combustion of low carbon fuel such as natural gas is s technologically feasible control option for the startup heater.

(d) Good Combustion Practices
The theory of GCP was discussed in detail in the NOx BACT for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of CO_2. Therefore good combustion practices is a feasible control option for the startup heater.

Step 2 – Eliminate Technically Infeasible CO_2 Control Options for the Startup Heater
As explained in Section 1.5, CCS is a technically infeasible control technology for the source.

Step 3 – Ranking of the Remaining CO_2 Control Technologies for the Startup Heater
The applicant has accepted all feasible control options. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA
Startup Heater (EU 13) – CO_2e

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0106	CF Industries Nitrogen, LLC	7/18/13	Startup Heater	58.8 MMBtu/hr	CO_2 - 117 lb/MMBtu (3 run avg.), CH_4 – 0.0023 lb/MMBtu, (3 run avg.), CO_2e – 345 tpy (12 month rolling), N_2O – 0.0006 lb/MMBtu (3 run avg.),	GCP & Limited Use
IA-0105	Iowa Fertilizer Company	10/26/12	Startup Heater	110.12 MMBtu/hr	CO_2 - 117 lb/MMBtu (3 run avg.), CH_4 – 0.0023 lb/MMBtu, (3 run avg.), CO_2e – 638 tpy (12 month rolling), N_2O – 0.0006 lb/MMBtu (3 run avg.),	GCP & Limited Use
IN-0172	Ohio Valley Resources	9/25/13	Ammonia Catalyst Startup Heater	106.3 MMBtu/hr	59.61 tons/MMcf (3-hr avg.), 20.84 MMcf/year	GCP, Design, & Fuel Type

IN-0180	Midwest Fertilizer Corporation	6/4/14	Startup Heater	92.5 MMBtu/hr	59.61 tons/MMcf (3-hr avg.), 18.14 MMcf/year	GCP, Design, & Fuel Type
IN-0179	Ohio Valley Resources	8/13/14	Ammonia Catalyst Startup Heater	106.3 MMBtu/hr	59.61 tons/MMcf (3-hr avg.), 20.84 MMcf/year	GCP, Design, & Fuel Type
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Startup Heater**	**101 MMBtu/hr**	**59.61 tons/MMcf, 1,200 tpy 200 hours/year**	**Limited Use**

RBLC Review
A review of similar units in the RBLC indicates add-on control technology is not practical for natural gas-fired process heaters. CO_2 emissions are controlled exclusively by use of low carbon fuel, proper design, good combustion practices, and limits on the hours of operation. 59.61 tons CO_2e per MMcf is equivalent to the GHG BACT limits for: Ohio Valley's reformer heater in the 9/25/13 PSD permit issued by the State of Indiana, Iowa Fertilizer Company's PSD permit issued on 10/26/12, and Magnolia Nitrogen's PSD permit issued on April 21, 2014.

Applicant Proposal
The applicant proposes the following as BACT:

(a) CO_2e emissions from the operation of the startup heater shall be controlled with limited use of the unit.

(b) CO_2e emissions from the startup heater shall not exceed 59.61 tons/MMcf of natural gas combusted, based on a three-hour average.

(c) Operating hours for the startup heater shall not exceed 200 hours per year.

(d) CO_2e emissions from the startup heater shall not exceed 1,200 tons per twelve consecutive month period with compliance determined at the end of each month.

(e) Compliance with the CO_2e limits will be determined by tracking operating hours for the startup heater.

Step 5 – Selection of CO_2e BACT for the Startup Heater
The Department agrees with the applicant that an emission rate achievable with limited use is BACT for the startup heater. CO_2e emissions from the startup heater (EU 13) shall not exceed 59.61 tons/MMcf of natural gas combusted and operating hours will be limited to 200 hours per year. Compliance with the proposed emission limit will be demonstrated by recording total operating hours for the startup heater.

1.6 CO_2 BACT for the Ammonia Tank Flare and Small Flares (EUs 11, 22, and 23)

Step 1 – Identification of CO_2 Control Technology for the Flares
From research, the Department identified the following technologies as available for CO_2 control of the flares:

(a) Flare Work Practice Requirements
Flare work practice requirements can be found in 40 CFR 60.18 (c) and (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 use of proper flare design and good combustion practices are technically feasible control options for the flares.

(b) Process Flaring Minimization Plan
Process flaring minimization plans define the procedures intended to reduce the volume of gas going to the flare without compromising plant operations and safety. Process flaring minimization practices is a technically feasible control option 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 for the KNO facility is not technically feasible because the gases controlled by the flares contain ammonia and are not suitable for use in other operations or as fuel at the plant.

Step 2 – Eliminate Technically Infeasible CO_2 Control Options for the Flares
As explained in Section 1.6, flare gas recovery is not feasible to control CO_2 emissions from the flares.

Step 3 – Ranking of the Remaining CO_2 Control Technologies for the Flares
The following control technologies have been identified and ranked for the control of CO_2 from the flares.

(a) Flare Work Practice Requirements
(b) Process Flaring Minimization Plan

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA
Ammonia Tank Flare, Plants 4 and 5 Small and Emergency Flares (EUs 11, 22, and 23) – CO_2e

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Work Practice & GCP
IN-0172 and IN-0179	Ohio Valley Resources	9/25/13	Two Front End Process Flares	0.25 MMBtu/hr (each)	116.89 lb/MMBtu (3-hr avg.), 511.8 tons/hour (SSM venting 3-hr avg. 336 hours/year)	FMP & Fuel Type
			Two Back End Ammonia Flares	0.25 MMBtu/hr (each)	116.89 lb/MMBtu (3-hr avg.), 127.12 tons/hour (SSM venting 3-hr avg. 336 hours/year)	
			Two UAN Vent Flares	0.19 MMBtu/hr (each)	116.89 lb/MMBtu (3-hr avg.), 5.59 tons/hour (SSM venting 3-hr avg. 336 hours/year)	
			Two Ammonia Storage Flares	0.13 MMBtu/hr (each)	52.02 lb/hour (3-hr avg.)	
IN-0180	Midwest Fertilizer Corporation	8/13/14	Front End Flare	4 MMBtu/hr	116.89 lb/MMBtu, 511.8 tons/hour (SSM venting 3-hr avg. 336 hours/year)	FMP & Fuel Type
			Back End Flare	4 MMBtu/hr	116.89 lb/MMBtu, 127.12 tons/hour (SSM venting 3-hr avg. 336 hours/year)	FMP & Fuel Type
			Ammonia Storage Flare	1.5 MMBtu/hr	116.89 lb/MMBtu (3-hr avg.), (SSM venting limited to 168 hr/yr)	FMP & Fuel Type
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Ammonia Storage Flare**	**1.25 MMBtu/hr**	**59.61 tons/MMcf, 645 tpy (SSM venting limited to 168 hr/yr)**	**Work Practice & FMP**
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Emergency Flare**	**0.4 MMBtu/hr**	**59.61 tons/MMcf, 206.4 tpy (SSM venting limited to 168 hr/yr)**	**Work Practice & FMP**
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Small Flare**	**1.25 MMBtu/hr**	**59.61 tons/MMcf, 645 tpy (SSM venting limited to 168 hr/yr)**	**Work Practice & FMP**

RBLC Review
Most of the RBLC control method entries for flares indicate that add-on controls are not typically used with flares. Greenhouse gas emissions are controlled by good combustion and design practices and the monitoring of the presence of a pilot flare. 59.61 tons CO_2e per MMcf is equivalent to the GHG BACT limits for: Ohio Valley's reformer heater in the 9/25/13 PSD permit issued by the State of Indiana, Iowa Fertilizer Company's PSD permit issued on 10/26/12, and Magnolia Nitrogen's PSD permit issued on April 21, 2014.

Applicant Proposal
The applicant proposes the following as BACT:

(a) Venting to the ammonia tank flare, small flare, and emergency flare shall not exceed 168 hours each, per 12-consecutive month period.

(b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:

(1) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable; and

(2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other maintenance events.

(c) Flare emissions shall be controlled by use of the following practices:

(1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed five minutes during any two consecutive hours;

(2) Flares shall be operated with a flame present at all times; and

(3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(d) CO_2e emissions from the ammonia tank flare, small flare, and emergency flare shall not exceed 59.61 tons/MMcf of natural gas combusted during normal operation, based on a three-hour average.

Step 5 – Selection of CO_2 BACT for the Ammonia Tank Flare, Small Flare, and Emergency Flare

The Department agrees with the applicant that an emission rate achievable with flare work practice requirements and developing a flare minimization is BACT for the flares. CO_2e emissions from the flares (EUs 11, 22, and 23) shall be controlled through work practices and by minimizing their use, and shall not exceed 59.61 tons/MMcf of natural gas combusted during normal operations. CO_2 emissions from the flares venting shall be limited to no more than 168 hours each, per rolling 12-consecutive months.

1.7 CO_2 BACT for the Well Pump and Fire Pump Engine (EUs 65 and 66)

Step 1 – Identification of CO_2 Control Technology for the Pump Engines
Stationary emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60 Subparts IIII and JJJJ, and 40 CFR 63 Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with the applicable emission limitations.

Step 2 – Eliminate Technically Infeasible CO_2 Control Options for the Pump Engines
The only feasible control option for the diesel-fired well pump and gasoline-fired fire pump engines is good combustion practices.

Step 3 – Ranking of the Remaining CO_2 Control Technologies for the Pump Engines
The applicant has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA
Diesel-Fired Well Pump and Gasoline-Fired Fire Pump Engines (EUs 65 and 66) – CO_2e

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IN-0172	Ohio Valley Resources	9/25/13	Diesel-Fired Emergency Water Pump	481 hp	CO_2 – 527.4 g/hp-hr (3-hr avg.), 200 hr/year	GCP
IA-0105	Iowa Fertilizer Company	10/26/12	Fire Pump	235 kW	CO_2e - 91 tons/12 month rolling, CO_2 – 1.55 g/kW-hr (3 stack test avg.), CH_4 – 0.0001 g/kW-hr, (3 stack test average)	GCP
LA-0254	Ninemile Point Generating Plant	12/12/11	Emergency Fire Pump	350 hp	CO_2 – 163 lb/MMBtu, CH_4 – 0.0061 lb/MMBtu, N_2O – 0.0014 lb/MMBtu	GCP

IN-0180	Midwest Fertilizer Company	8/13/14	Fire Pump	500 hp	CO_2 – 527.4 g/hp-hr (3-hr avg.), 500 hours/year	GCP & Limited Use
MD-0040	CPV St. Charles	11/12/08	Emergency Fire Water Pump	300 hp	CH_4 – 3 g/hp-hr	None
IN-0166	Indiana Gasification LLC	6/27/12	Three Firewater Pump Engines	575 hp (each)	CO_2 – 84 tpy	Design, NSPS, & MACT
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Diesel-Fired Well Pump Engine**	**2.7 MMBtu/hr**	164 lb/MMBtu (3-hr avg.), 37.2 tpy, 12 hr/yr	GCP & Limited Use
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**Gasoline-Fired Fire Pump Engine**	**2.1 MMBtu/hr**	154 lb/MMBtu (3-hr avg.), 27.2 tpy, 60 hr/yr	Limited Use

RBLC Review
A review of similar units in the RBLC indicates add-on control devised are not typically used. The only control method is good combustion practices.

Applicant Proposal
The applicant proposes the following as BACT:

(a) CO_2e emissions from the operation of the diesel-fired well pump and gasoline-fired fire water pump shall be controlled with limited use of the units.

(b) CO_2e emissions from the diesel-fired well pump shall not exceed 164 lb/MMBtu, based on a three-hour average.

(c) CO_2e emissions from the gasoline-fired fire water pump shall not exceed 154 lb/MMBtu, based on a three-hour average.

(d) The hours of operation for EUs 65 and 66 shall not exceed 168 hours per year, each.

Step 5 – Selection of CO_2 BACT for the Well Pump and Fire Water Pump Engines
The Department agrees with the applicant that an emission rate achievable with limited use is BACT for the pump engines. CO_2e emissions from the diesel-fired well pump engine (EU 65) and the gasoline-fired fire pump engine (EU 66) shall not exceed 164 lb/MMBtu and 154 lb/MMBtu, respectively, and operating hours will be limited to 168 hours per year each. Compliance with the proposed emission limit will be demonstrated by recording and reporting operating hours for the pump engines.

1.8 CO_2 BACT for the CO_2 Vent (EU 14)

Step 1 – Identification of CO_2 Control Technology for the CO_2 Vent
The Department has identified the following control technologies for the CO_2 purification process.

(a) Carbon Capture and Storage
The theory of CCS was discussed in detail in the CO_2 BACT for the turbines and will not be repeated here. It was determined that CCS is not a technically feasible control technology for the entire source and has been eliminated from further consideration for GHG BACT.

(b) Use of CO_2 as Raw Material to Manufacture Urea (Good Operational Practices)
The KNO facility's CO_2 purification process is designed to use a portion of the CO_2 created in the ammonia plant to manufacture urea. By using CO_2 as a raw material, CO_2 emissions to the atmosphere are reduced significantly. Good operational practices to use as much CO_2 in the manufacture of urea is a technically feasible control strategy for the CO_2 vent.

Step 2 – Eliminate Technically Infeasible CO_2 Control Options for the CO_2 Vent
As discussed in Section 1.8 the use of CCS is a technically infeasible option for controlling CO_2 emissions from the source.

Step 3 – Ranking of the Remaining CO_2 Control Technologies for the CO_2 Vent
The applicant has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
The following table lists the proposed BACT determination for the facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the applicant, the U.S. EPA RACT/BACT/LEAR Clearinghouse (RBLC), Alaska issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA
CO_2 Vent (EU 14) – CO_2e

RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	CO_2 Regenerator	3,012 metric tons/day	CO_2 –1.26 lb/ton of NH_4 (30-day avg.), CO_2e – 1,211,847 tons per 12-month rolling	Good Operational Practices
IN-0180	Midwest Fertilizer Company	6/4/14	CO_2 Purification Process	2,400 tons/day ammonia	CO_2 – 1.275 tons CO_2e/ton of NH_4 (3-hr avg.), 100% CO_2 venting, 1,232,475 ton CO_2 / 12 month rolling	Good Operational Practices, Usage Limit
IN-0172	Ohio Valley Resources	9/25/13	CO_2 Purification Process	3,570 tons CO_2/day	CO_2 – 1.275 tons CO_2 / ton of NH_4 (3-hr avg.), 1,022,000 ton CO_2 / 12 month rolling	Good Operational Practices
IA-0106	CF Industries Nitrogen, LLC	7/18/13	Carbon Dioxide Regenerator	111.15 tons NH_4/hr	1.26 lb/ton NH_4 (30-day rolling avg.), 1,226,814 tons CO_2 / 12 month rolling	Good Operating Practices

OK-0135	Pryor Plant Chemical	2/18/10	CO_2 Vent	36.5 tons CO_2/hr	3.65 lb/hr (1-hr / 8-hr avg.)	Good Operational Practices
IN-0179	Ohio Valley Resources	8/13/14	CO_2 Purification Process	3,570 tons CO_2/day	1.275 tons CO_2 / ton of NH_4 (3-hr avg.), 1,022,000 tons NH_4 produced /year	Good Operational Practices
LA-0272	Dyno Nobel Louisiana	3/27/13	CO_2 Stripper Vent	115.83 tons/hour	1,280,000 tpy	Improved Solvents to Minimize Energy
AQ0083CPT06	**Kenai Nitrogen Operations**	**Proposed**	**CO_2 Vent**	**90 tons NH_4/ hour**	**845,486 tons/year**	**Good Operational Practices**

RBLC Review
Entries in the RBLC table above, indicate add-on control devices are not included in the BACT determinations for the CO_2 purification process. The entries show BACT as good operational practices that use CO_2 as a raw material to produce urea.

Applicant Proposal
The applicant proposes the following as BACT:

(a) The applicant proposes to use CO_2 from the CO_2 purification process for the manufacture of urea while the urea unit is operating.

(b) CO_2e emissions from the CO_2 vent shall not exceed 845,486 tons per 12-consecutive month period with compliance determined at the end of each month.

Step 5 – Selection of CO_2 BACT for the CO_2 Vent
The Department agrees with the applicant that an emission rate achievable with good operational practices is BACT for the CO_2 vent. CO_2 emissions from the CO_2 vent (EU 14) shall not exceed 1.62 tons CO_2 per ton of ammonia produced or 845,486 tons of CO_2 per year.

APPENDIX D: MODELING REPORT

Alaska Department of Environmental Conservation

Air Permit Program

Review of Agrium's Ambient Demonstration

for the

Kenai Nitrogen Operations Restart Project

Construction Permit AQ0083CPT06

Prepared by: Alan Schuler
November 26, 2014

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Table of Contents

1. INTRODUCTION

This report summarizes the Department's findings regarding the ambient demonstrations submitted by Agrium U.S. Inc. (Agrium) for the Kenai Nitrogen Operations (KNO) restart project. Agrium submitted this analysis in support of their October 2013 Prevention of Significant Deterioration (PSD) permit application (AQ0083CPT06). The project triggers PSD review for oxides of nitrogen (NOx), particulate matter with an aerodynamic diameter of less than or equal to 10 microns (PM-10), particulate matter with an aerodynamic diameter of less than or equal to 2.5 microns (PM-2.5), carbon monoxide (CO), ozone (O_3), and greenhouse gases (GHG).

Agrium's application adequately complies with the 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). Agrium's ambient analysis adequately demonstrates that operating the KNO emissions units (EUs) within the restrictions listed in this report will not cause or contribute to a violation of the: 1-hour and annual nitrogen dioxide (NO_2), 1-hour and 8-hour CO, 24-hour PM-10, 24-hour and annual PM-2.5, 8-hour O_3, and 8-hour ammonia (NH_3) Alaska Ambient Air Quality Standards (AAAQS) listed in 18 AAC 50.010. Agrium's ambient analysis also demonstrates compliance with the annual NO_2, 24-hour and annual PM-10, and 24-hour and annual PM-2.5 Class I and Class II maximum allowable increases (increments) listed in 18 AAC 50.020.[1]

2. REPORT OUTLINE

As indicated in the opening paragraph, Agrium's project triggers numerous ambient demonstration requirements. The Department's findings regarding Agrium's approach for meeting the pre-construction monitoring requirement in 40 CFR 52.21(m) is described in the **Ambient Air Pollutant Data** section of this report. The Department's findings regarding Agrium's additional impact analysis under 40 CFR 52.21(o) is described in the **Additional Impact Analysis** section.

Agrium needed to use a variety of means to fully address the ambient demonstration requirement in 40 CFR 52.21(k). Agrium used computer analysis (modeling) to predict the ambient NO_2, PM-10, PM-2.5, CO and NH_3 air quality impacts. They used the AERMOD Modeling System (AERMOD) in their "near-field" analysis – i.e., impacts within 50 km of their stationary source. They used the CALPUFF Modeling System (CALPUFF) to estimate the Class I increment impacts at locations beyond 50 km of their stationary source. Agrium used a qualitative approach to address the ambient O_3 impacts. The Department's findings regarding these assessments are respectively in the **Near-field AERMOD Analysis**, the **CALPUFF Class I Increment Analysis**, and **Ozone Impacts** sections of this report.

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

3. BACKGROUND

KNO is an existing fertilizer manufacturing facility that has been inoperative for the last several years. At Agrium's request, the Department rescinded all previous air quality control permits and application shields on October 26, 2009. The Department further noted that, "resumption of emitting activities at the Kenai Nitrogen Operations will constitute a new stationary source under Air Quality Control Regulations." Agrium is proposing to restart a portion of the KNO facility. Therefore, while the KNO facility exists, the Department is treating it as a new stationary source for air quality permitting purposes.

3.1. Project Location and Area Classification

KNO is located near Kenai, Alaska. The area is unclassified in regards to compliance with the AAAQS. For purposes of increment compliance, KNO is located within a Class II area of the Cook Inlet Intrastate Air Quality Control Region. The nearest Class I areas are the Tuxedni National Wildlife Refuge (Tuxedni) and Denali National Park (Denali). Tuxedni is located approximately 90 kilometers (km) to the southwest. Denali is located approximately 200 km to the north.

3.2. Ambient Demonstration Requirements

In accordance with 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:

- A Source Impact Analysis – 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 Air Quality Analysis, i.e., pre-construction monitoring data, for the PSD-triggered pollutant with an associated ambient air quality standard or increment, per 40 CFR 52.21(m);
- An Additional Impact Analysis per 40 CFR 52.21(o); and
- A Class I Impact Analysis, for stationary sources that may affect a Class I area, per 40 CFR 52.21(p).

The 2010 Federal Land Manager's Air Quality Related Values Work Group (FLAG) report details a screening procedure for assessing when a PSD project is too small or too distant to warrant a Class I impact analysis. Agrium provided the Department with an emissions-to-distance (Q/d) evaluation for the KNO restart project observing this procedure. The Q/d values were 6.2 for Tuxedni and 2.7 for Denali. Values that are less than 10 indicate the project will have negligible impacts with respect to Class I air quality related values (AQRVs). The Department forwarded this information to the Tuxedni and Denali federal land managers (FLMs) on November 19, 2013. The Department stated that it would not be requesting a Class I AQRV analysis under 40 CFR 52.21(p) due to the low Q/d values, unless the FLMs stated otherwise. The Denali FLM, the National Park Service (NPS), stated on November 19, 2013 that they did not request an AQRV analysis, but they want to be copied "on any public notice, draft permit, and staff analysis." The Tuxedni FLM, the U.S. Fish and Wildlife Service (FWS), did not reply.

In addition to assessing the ambient impacts from the PSD-triggered pollutants, Agrium also submitted an ambient demonstration with the State's 8-hour ammonia (NH_3) AAAQS. This assessment is appropriate since fertilizer plants can emit substantive NH_3 emissions.

3.3. Modeling Protocol Submittal

Agrium submitted a modeling protocol for Department review on February 18, 2014. ERM Group, Inc. (ERM) prepared the protocol on Agrium's behalf. AMEC Environment & Infrastructure, Inc. (AMEC) reviewed the protocol on behalf of the Department. Agrium submitted a revised version, in response to AMEC and Department comments, on June 10, 2014. The Department approved the protocol, with comment, on July 18, 2014.

3.4. Application Submittal

Agrium submitted a partial permit application on October 24, 2013 while continuing to develop the ambient portion of their application. Agrium subsequently submitted various revisions. They submitted the ambient demonstration on September 5, 2014 and revised versions of select aspects of their demonstration on October 20, 2014, November 10, 2014, November 19, 2014, and November 21, 2014. Agrium submitted the PM-10, PM-2.5, and O_3 pre-construction monitoring data as described in Section 4 of this report. ERM prepared the application and ambient analysis on Agrium's behalf.

4. AMBIENT AIR POLLUTANT 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 (SMC) provided in 40 CFR 52.21(i)(5).[2] The requirement only pertains to the pollutants subject to PSD review. 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. Agrium's approach for meeting the pre-construction data needs is discussed below. Agrium's approach for meeting the "background" data needs is described in the *Offsite Impact* sub-section of the *Near-field AERMOD Analysis* section of this report.

[2] The SMC for PM-2.5 was vacated on January 22, 2013 by the District of Columbia Circuit Court. Therefore, projects that trigger PSD review for PM-2.5 must include pre-construction monitoring data, regardless of the project impacts.

4.1. Pre-Construction Monitoring

Agrium used computer analysis (modeling) to compare the NOx, PM-10 and CO project impacts to the SMCs.[3] Agrium used the methodology discussed in the *Source Impact Analysis* sub-section of the *Near-field AERMOD Analysis* section of this report for the modeling analysis. The maximum project impacts are shown in Table 1, along with the applicable SMC. All values are reported in micrograms per cubic meter (μg/m^3).

Table 1. Pre-Construction Monitoring Assessment

Air Pollutant	Avg. Period	Project Impact (μg/m^3)	SMC (μg/m^3)
NO_2	Annual	**7**	14
CO (Startup Scenario)	8-hr	**3,566**	575
CO (All Other Scenarios)		**279**	
PM-10	24-hr	**22**	10

The maximum annual average NO_2 impact is less than the SMC. Therefore, preconstruction monitoring is not required for NO_2. The maximum 8-hour CO impact during the startup scenario exceeds the SMC and the maximum 24-hour PM-10 impact likewise exceeds the SMC.

Agrium noted that they anticipate operating under the startup scenario for no more than 200 hours per year and that the maximum CO impact would be less than the SMC during the rest of the year. They also noted that a pre-construction monitoring data set collected by Union Oil Company of California (UOCC) at the Swanson River Field demonstrates that the existing CO concentrations comply with the CO AAAQS. UOCC collected the data between May 2008 and April 2009. The Department determined that the data meets the PSD quality assurance requirements on September 11, 2009.

Agrium stated the UOCC CO data is representative of the expected existing CO impacts at KNO since the combustion sources at Swanson River are similar to the nearby sources, and since high ambient CO concentrations are typically associated with motor vehicle emissions. Agrium further noted that the vehicle volumes near KNO are relatively low and the vehicle speeds are high, which leads to lower CO emissions than what occurs during idle or low speed conditions. Agrium's position is reasonable. As shown below in Table 2, the maximum CO concentrations measured at Swanson River are well below the CO AAAQS.[4]

[3] Agrium used a conservative approach for estimating their project impacts. They included the secondary emissions (in this case, marine vessel emissions) as if they were part of their stationary source. Therefore, the maximum modeled impacts are potentially larger than what may have been found if Agrium only modeled the KNO EUs.

[4] Agrium used the conservative approach of reporting the first-high CO concentrations measured at Swanson River, rather than the second-high value allowed under the AAAQS.

Table 2. Maximum CO Concentrations Measured at Swanson River

Avg. Period	Max Conc ($\mu g/m^3$)	AAAQS ($\mu g/m^3$)	% of AAAQS
1-hr	**2,500**	40,000	6%
8-hr	**1,100**	10,000	11%

Agrium fulfilled the pre-construction monitoring requirement for O_3, PM-10, and PM-2.5, by collecting PSD-quality ambient data at the project site. Pre-construction monitoring data must be collected at a location and in a manner that is consistent with the U.S. Environmental Protection Agency's (EPA's) *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA-450/4-87-007), which is adopted by reference in 18 AAC 50.035(a)(5). In summary, the data must be collected at the location(s) of existing and proposed maximum impacts, the data must be current, and the data must meet the state and PSD quality assurance requirements per 18 AAC 50.215(a).

The Department approved Agrium's PM-2.5 monitoring location on August 26, 2013, the PM-10 monitoring location on September 11, 2013, and the O_3 monitoring location on October 28, 2013. Agrium used the same location for all three pollutants. The Department accepted Agrium's proposal to limit the O_3 monitoring effort to the April through October 2014 "ozone season" as part of its siting approval.

Agrium submitted a single Quality Assurance Project Plan (QAPP) for the PM-2.5 and PM-10 monitoring effort. Eastern Research Group (ERG) reviewed the particulate matter (PM) QAPP on behalf of the Department. The Department approved the PM QAPP on February 26, 2014. Agrium submitted a separate QAPP for their O_3 monitoring effort. AMEC reviewed the O_3 QAPP on behalf of the Department. The Department approved the O_3 QAPP on April 1, 2014.

Agrium collected PM data from October 1, 2013 through September 30, 2014. They submitted their PM data for Department review on October 24, 2014. Agrium collected O_3 data from April 1, 2014 through October 31, 2014, and submitted it for Department review on November 14, 2014. The Department accepted the PM-10, PM-2.5 and O_3 data on November 26, 2014.

The maximum concentrations measured by Agrium are provided in Table 3 below. The reported values were calculated in a manner that is consistent with the form of each AAAQS. The ozone concentration is in parts per billion (ppb). The PM-10 and PM-2.5 concentrations are in $\mu g/m^3$. The AAAQS for each pollutant is also provided. All of the concentrations are less than the AAAQS.

Table 3. Maximum Ambient Concentrations Measured by Agrium

Air Pollutant	Avg. Period	Monitoring Period	Max Conc	AAAQS	% of AAAQS
PM-10	24-hour	Oct. 1, 2013 – Sept. 30, 2014	**58.5 μg/m^3**	150 μg/m^3	39%
PM-2.5	24-hour		**8.0 μg/m^3**	35 μg/m^3	23%
	Annual		**3.6 μg/m^3**	15[a] μg/m^3	24%
O_3	8-hour	Apr. 1, 2014 – Oct. 31, 2014	**60.0 ppb**	75 ppb	80%

Table Note:

[a] The Department has not yet adopted EPA's revised annual PM-2.5 standard of 12 μg/m^3. However, the annual average PM-2.5 concentration measured by Agrium is less than the annual PM-2.5 National Ambient Air Quality Standard (NAAQS) as well as the annual PM-2.5 AAAQS.

5. NEAR-FIELD AERMOD ANALYSIS

There are a number of air dispersion models available to applicants and regulators. EPA lists these models in their *Guideline on Air Quality Models* (Guideline), which the Department has adopted by reference in 18 AAC 50.040(f). Agrium used AERMOD to demonstrate compliance with the NO_2, PM-10, PM-2.5, CO and NH_3 AAAQS and Class II increments, as applicable.

5.1. Approach

Agrium identified four *short-term* operating scenarios that could occur during any given year. With one exception, they modeled each of the four scenarios for those pollutants with a short-term AAAQS or increment. The exception regards the 1-hour NO_2 AAAQS, which is discussed later in this report. When modeling *annual* average impacts, Agrium assumed all EUs are operating at their respective annual operating limit (see *EU Inventory* section).

Agrium identified and described the short-term operating scenarios as:

- S1 – "***normal***" operation. In this scenario, the exhaust from each Solar combustion turbine is routed through a Waste Heat Recovery (WHR) boiler, and then through a selective catalytic reduction (SCR) control system to reduce the NOx emissions. The Startup Heater (EU 13) and the Hydrogen Vent Stack (EU 19) are not operated during normal operations.
- S2 – "***bypass***" scenario. This scenario is identical to the normal operation scenario, except the exhaust from one of the combustion turbines bypasses the WHR boiler and SCR control system. Agrium stated this scenario would occur for no more than one week per year per WHR boiler, for maintenance reasons.
- S3 – reformer "***startup***" scenario. Agrium anticipates up to four startup/shutdown events per year and one catalyst change out per year of the Primary Reformer (EU 12). During

these events, Agrium would operate the Startup Heater (EU 13) to warm-up the Primary Reformer. For modeling purposes, Agrium initially assumed the Primary Reformer would be at 50-percent capacity, since that is the level it needs to obtain before taking the Startup Heater off line. They later assumed the Primary Reformer is at full load, in order to avoid possible permit restrictions. Agrium will also operate the Hydrogen Vent Stack (EU 19) during the startup scenario.

- S4 – plant "***turnaround***" scenario. Agrium will need to take the Primary Reformer (EU 12) off-line once every four years for maintenance purposes. The Startup Heater (EU 13), the Hydrogen Vent Stack (EU 19), the Waste Heat Recovery boilers (EU 50 – 54) and four of the five Solar combustion turbines (EU 55 – 59) will not operate during plant turn-around. The turbine that does operate would be in bypass mode. There could also be flaring from the Plants 4 and 5 Small Flare (EU 22) and Plants 4 and 5 Emergency Flare (EU 23).

Agrium indicated that urea or NH_3 ship loading could occur during any of the above scenarios, but that only one vessel could be loaded at a time. Since the vessel emissions vary by product, Agrium provided two sets of results for each run: one where a urea vessel is being loaded during the entire averaging period, and the other where ammonia is being loaded on a vessel during the entire averaging period. Agrium reported each result in their modeling report.

Agrium also used a multi-step modeling approach for each run. They first modeled just the KNO EUs, along with the vessel emissions, and compared these impacts to the significant impact levels (SILs) for AAAQS and Class II increments listed in Table 5 of 18 AAC 50.215(d). Impacts less than the SIL may be considered as negligible since none of the AAAQS are threatened.

Agrium found that all of the project impacts exceeded the applicable SIL, and that *cumulative* AAAQS and Class II increment assessments were needed. The Department is not providing the intermediate "project impact" results in this report, except as already provided in Table 1. The project impacts for all scenarios, pollutants and averaging periods may be found in Table 12 of Agrium's ambient demonstration.

5.2. Model Selection

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. Agrium used the current version of AERMAP, version 11103, and AERMOD, version 14134. Agrium did not need to run AERMET, for the reason described in the *Meteorological Data* section.

5.3. Meteorological Data

AERMOD requires hourly meteorological data to estimate plume dispersion. According to the Guideline, a *minimum* of one-year of site-specific data, or five years of representative

National Weather Service (NWS) data should be used. Agrium used five years (2008 - 2012) of NWS data from the Kenai airport for their AERMOD modeling analysis. Kenai data adequately represents the plume transport conditions at KNO.

Agrium obtained the Kenai data in an AERMOD-ready format from the Department web-site: http://dec.alaska.gov/air/ap/AERMOD_Met_Data.htm. The meteorological data was originally processed by Hilcorp Alaska, LLC (Hilcorp) in support of a minor permit application for the Paxton Production Pad (Minor Permit AQ1286MSS01). Hilcorp augmented the surface data with upper air data from the nearest NWS upper air station, Anchorage. Hilcorp used the current version of AERMET, version 14134, and the current version of the AERMINUTE preprocessor, version 11325. Additional details regarding Hilcorp's processing of the Kenai NWS data may be found in Appendix B of the Technical Analysis Report (TAR) for Minor Permit AQ1286MSS01.

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. Agrium used the Universal Transverse Mercator (UTM) system.

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, unless the terrain features are so slight that a "flat terrain" assumption can be made. AERMOD's terrain preprocessor, AERMAP, utilizes digital terrain data to obtain the elevation for EUs, building bases, and receptors.

Agrium used AERMAP and National Elevation Dataset (NED) files for their terrain analysis. NED is the current terrain elevation dataset provided by the Unites States Geological Survey.

5.6. EU Inventory

Agrium modeled the EUs listed in the *EU Inventory* of Construction Permit AQ0086CPT06. They also included the fugitive NH_3 emissions in the NH_3 ambient demonstration. Agrium characterized most of the emissions as point source releases. However, they characterized the NH_3 fugitive emissions, the urea ship loading emissions (EU 47), and the urea warehouse and tripper belt emissions (EU 47B), as volume sources. These are appropriate methods for characterizing these emission releases. Agrium treated all KNO emissions as increment consuming.

5.6.1. Annual Operational Assumptions

Agrium generally assumed each EU operates continuously throughout the year. The exceptions are listed below, along with the Department's assessment as tow whether the annual operating assumptions need to be imposed as ambient air permit limits.

- **Solar Combustion Turbines (EU 55 – 59) in Bypass Mode**: Agrium assumed the bypass mode lasted 204 hours per year (hrs/yr). Since the turbine NOx emission rate increases by an order of magnitude in bypass mode, the Department is imposing the 204 hrs/yr assumption as an ambient limit to protect the annual NO_2 AAAQS and increment.

  The bypass mode does not increase the turbine emissions for the other pollutants. However, the ambient impacts could be greater due to the shorter stack height. The Department is therefore imposing the 204 hrs/yr assumption as an ambient limit to protect the annual PM-10 increment, and the annual PM-2.5 AAAQS and increment.

  Annual operating assumptions can also affect the emissions profile used to model 1-hour NO_2 impacts. However, the Department ran a 1-hour NO_2 sensitivity analysis where one of the solar turbines (EU 55) is in bypass mode on a year-round basis.[5] The maximum impact did not change. Therefore, the Department is not imposing the 204 hrs/yr limit to protect the 1-hour NO_2 AAAQS.
- **Startup Heater (EU 13)**: Agrium stated EU 13 would not be operated for more than 200 hrs/yr. The Department is therefore imposing this assumption as an ambient limit to protect the annual NO_2 AAAQS and increment, the annual PM-10 increment, and the annual PM-2.5 AAAQS and increment. The Department is also imposing this limit to protect the 1-hour NO_2 AAAQS.
- **Hydrogen Vent Stack (EU 19)**: Agrium stated EU 19 would not be operated for more than 200 hrs/yr. However, this EU only emits CO and NH_3, which have no annual average AAAQS or increments. Therefore, this limitation is not needed to protect the AAAQS and increments.
- **Diesel Fired Well Pump (EU 65)** and **Gasoline Fired Firewater Pump (EU 66)**: Agrium originally assumed that EU 65 would operate for no more than 12 hrs/yr and that EU 66 would operate for no more than 60 hrs/yr. Agrium increased this assumption to 168 hrs/yr, per unit, in the October and November modeling submittals. The Department is therefore imposing the 168 hrs/yr assumption as an ambient limit to protect the annual NO_2 AAAQS and increment, the annual PM-10 increment, and the annual PM-2.5 AAAQS and increment.

5.6.2. Short-term Operational Assumptions

Agrium assumed most EUs operate continuously throughout the year. However, there are several exceptions in addition to the annual operating assumptions described above.

Agrium modeled each of the short-term operating scenarios described in Section 5.1 in order to demonstrate that the short-term AAAQS and increments would be protected during all scenarios. In all but one case, the maximum impacts did not substantially vary between scenarios. This indicates the maximum impacts are more associated with the constantly operating EUs, than the EUs that only operate during some of the scenarios.

[5] Agrium likewise assumed one of the turbines is constantly in by-pass mode in their November 2014 submittals.

The CO analysis is the exception. In this case, the maximum 1-hour and 8-hour CO impacts associated with the reformer startup scenario are three-times greater than the maximum impacts associated with the other scenarios. The increase is due to the **H2 Vent Stack (EU 19)**, which has substantive CO emissions and which only operates during the reformer startup scenario.

The start-up scenario also incorporated a fifty-percent reduction in the CO emissions from the **Primary Reformer (EU 12)**, due to the part-load operating assumption. This could have led to part-load operating restriction in the permit. However, Agrium submitted a CO sensitivity analysis on October 30, 2014 to show that this type of restriction is not needed. Agrium modeled the maximum CO emission rate allowed under any scenario in a combined run. The maximum 1-hour CO impact increased by a third of one percent, which is inconsequential. The maximum 8-hour CO impact did not change at all. Therefore, the Department does not need to restrict the part-load operation of EU 12 in order to protect the 1-hour and 8-hour CO AAAQS.[6]

The Department conducted a similar 1-hour NO_2 sensitivity analysis in October 2014 to further confirm that there is no need for imposing a part-load restriction. The Department chose the 1-hour NO_2 pollutant and averaging period since it has the smallest margin of compliance of all the modeled pollutants. The Department also noted that the NOx emissions from the **Solar Turbines (EUs 55 – 59)** and **Plants 4 and 5 flares (EUs 22 – 23)** greatly vary by scenario. Using a combined run addresses whether these units need to be restricted by operating scenario. It also provides a more robust demonstration for a probabilistic standard. The Department found that the maximum 1-hour NO_2 impact did not change. Agrium subsequently corrected several stack errors in the modeling files and submitted a revised combined run on November 19, 2014. These sensitivity runs show that there is no need to impose a requirement to: track and report a change in operating scenario; limit the load on the **Primary Reformer (EU 12);** or limit when the **Plants 4 and 5 flares (EUs 22 – 23)** can operate.

While the Department is not imposing a condition that restricts operation by scenario, there are several other modeling assumptions that are being translated into permit conditions. These other short-term operational assumptions are summarized below, along with the Department's assessment regarding the potential need for ambient air limits.

- **Diesel Fired Well Pump (EU 65)**: Agrium assumed EU 65 could operate during any of the short-term scenarios. They also stated that they would not operate this EU for more than an hour per day.

[6] Agrium submitted a revised CO sensitivity on November 10, 2014, which contained corrected stack parameters for the package boilers (EU 44, 48 and 49). They submitted another revision on November 19, 2014, which contained additional corrections to the stack outlets for EU 13, 60 and 61. The corrections did not alter the maximum impacts or conclusions associated with the October 2014 submittal.

Agrium did not incorporate the hour-per-day intent in their modeling analysis. They instead assumed continuous operation in the short-term PM-10, PM-2.5, and CO demonstrations. They used the annual NOx emission rate for the 1-hour NO_2 analysis, as allowed under EPA guidance.[7] Therefore, the Department is not imposing Agrium's hour-per-day intention as an operating limit.

- **Gasoline Fired Firewater Pump (EU 66)**: Agrium assumed EU 66 could operate during any of the short-term scenarios. However, they also assumed that EU 66 would not operate for more than four hours per day in their 24-hour PM-10 and 24-hour PM-2.5 assessments. The Department is therefore imposing this assumption as an ambient air limit to protect the 24-hour PM-10 AAAQS and increment, and the 24-hour PM-2.5 AAAQS and increment.
- **Solar Combustion Turbines (EU 55 – 59) in Bypass Mode**: Agrium assumed no more than one turbine would be in bypass mode at a time. Given the previously discussed stack height and NOx emission rate considerations, the Department is imposing this assumption as an ambient condition to protect the short-term AAAQS and increments for NO_2, CO, PM-10 and PM-2.5, as applicable. The limit is not needed to protect the 8-hour NH_3 AAAQS since bypassing the SCR unit decreases NH_3 emissions.

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…"

The restarting of KNO will lead to ship activity at the Agrium wharf. The ships are not part of the KNO stationary source, but they will be there because of the KNO operation. The ship emissions associated with providing power and heat while docked (aka hoteling emissions) fall under the secondary emissions category and therefore, must be included in the AAAQS and increment demonstrations. Agrium identified and characterized two types of ships that will be used for transporting product to market: urea vessels and ammonia vessels.

Construction activities can also be considered as secondary emissions. However, the tailpipe emissions from the mobile source component are not considered as secondary emissions and are not included in analysis. The KNO restart project will require relatively little construction activity since most components already exists. Agrium also noted that most of the construction activity that would occur would come from tailpipe emissions. Agrium therefore did not include construction emissions in their ambient demonstration. Agrium's approach is reasonable. The post-construction stationary

[7] EPA Memorandum, *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard*, March 1, 2011.

source emissions that they modeled far exceed the construction-phase secondary emissions.

5.7. Load Analysis

The maximum ambient pollutant concentration does not always occur during the full-load operating conditions that typically produce the maximum emissions. The relatively poor dispersion that occurs with cooler exhaust temperatures and slower part-load exit velocities may produce the maximum ambient impacts. Turbine emissions also tend to greatly vary by fuel type, load, and inlet air temperature. Therefore, EPA recommends that a load analysis be conducted on the primary EUs to determine the worst-case conditions.

Agrium stated that they will typically operate KNO at full-load conditions for economic reasons. They nevertheless conducted a load analysis of the **Primary Reformer (EU 12)**, since it will operate at part-load during start-up, the **Granulators (EU 35 – 36)**, the **Package Boilers (EU 44**, **48** and **49)**, and the **Solar Turbines/Waste Heat Boilers (EU 50 – 59)**. Agrium described their load analysis in Section 8.1 and Appendix F of their ambient demonstration. Agrium concluded that the full-load conditions should be used for their modeling analysis. The Department agrees with their finding.

5.8. EU Characterization

Agrium appropriately characterized their EUs. However, some aspects warrant additional discussion.

5.8.1. Emission Rates

The modeled emission rates are consistent with the emissions information provided throughout the application. Since these emission rates generally reflect the Department's Best Available Control Technology (BACT) analysis, the Department is imposing compliance with the BACT emission rates as ambient air conditions.

5.8.2. Point Source Parameters

Applicants must provide the stack height, diameter, location, and base elevation in addition to the pollutant emission rates, exhaust plume exit velocity, and exhaust temperature for each modeled point source.

The Department generally found the modeled stack parameters to be consistent with the vendor information or expectations for similarly sized EUs. The exceptions, or items that otherwise warrant additional discussion, are discussed below.

5.8.2.1 Stack Heights

KNO has a number of tall structures that could lead to substantive downwash from the exhaust stacks. Agrium instead designed most of the exhaust stacks with fairly high release points. It seems evident that these heights are needed to enhance plume dispersion. The Department is therefore imposing the stack heights listed in Table 4 as ambient air conditions. Since the pollutants vary by stack, the pollutants associated with each stack is also listed.

Table 4. Minimum Stack Height Requirements

EU	Description	Emitted Pollutants	Min. Stack Height (ft)
12	Primary Reformer	NOx, CO, PM-10, PM-2.5	100
14	CO_2 Vent	CO, NH_3	154
19	H2 Vent Stack	CO, NH_3	80
35 - 36	Granulator Scrubber Exhaust Vents Stack	PM-10, PM-2.5, NH_3	140
44, 48, 49	Package Boilers	NOx, CO, PM-10, PM-2.5	100
50 - 54	Waste Heat Boilers	NOx, CO, PM-10, PM-2.5	100
55 - 59	Solar Turbines (bypass stacks)	NOx, CO, PM-10, PM-2.5	60

5.8.2.2 Horizontal/Capped Stacks

The presence of non-vertical stacks or stacks with rain caps requires special handling in an AERMOD analysis. The proper approach for characterizing these types of stacks is described in EPA's *AERMOD Implementation Guide*. When specifying the model parameters for non-vertical or capped stacks that are subject to building downwash, a user should input the actual stack diameter and exit temperature, but set the exit velocity to a nominally low value i.e. 0.001 meters-per-second (m/s). If the non-vertical or capped stack is not subject to downwash, then the aforementioned 0.001 m/s exit velocity should be used along with a surrogate diameter that allows the actual exhaust flow rate to be maintained. Minor adjustments to the stack height may also be warranted.

EPA has developed a non-default option in AERMOD that will revise the stack characteristics as warranted, for stacks that are identified as horizontal or capped. EPA Region 10 granted the Department permission to generally use this option in October 2007.[8]

Agrium identified the following stacks as having capped or horizontal releases:

- **Startup Heater (EU 13)**
- **Tank Scrubber (EU 41)**
- **Urea Warehouse Baghouse Stack (EU 47C)**
- **Urea Transfer Baghouse Stack – Wharf (EU 47D)**
- **Deaerator Vent (EU 60)**
- **Degasifier Vent (EU 61)**

[8] E-mail from Herman Wong (EPA Region 10) to Alan Schuler (Department), *RE: Capped/Horizontal Stack Issue;* October 2, 2007.

- **Diesel Fired Well Pump (EU 65)**
- **Gasoline Fired Firewater Pump (EU 66)**

Agrium used the non-default option in AERMOD to properly characterize these stacks, along with the off-site EUs with capped or horizontal releases. Agrium characterized all of stacks as having uncapped, vertical releases. Because the near-field impacts from horizontal or capped stacks are typically greater than the impacts from stacks with vertical, uncapped discharges, the Department is including a permit condition that requires vertical, uncapped stacks, except for the EUs listed above.[9]

5.8.2.3 Urea Ship Stack Parameters

Agrium used a stack temperature of 358K (185°F) for the urea ship stack, which may be unrealistically cool for combustion-related exhaust. They also used an exit velocity of 6.14 meters per second, which is roughly half of the value derived from the 3,360 cubic meter per hour exhaust flow rate provided in Agrium's modeling report. While these values are questionable, they characterize the plume as being less buoyant than what it likely is, which in turn would likely cause AERMOD to over-predict the actual ambient impacts from the urea ship. Agrium's use of these values is therefore acceptable.

5.8.3. Flare Characterization

Agrium intends to operate three flares at KNO (**EU 11**, **22** and **23**). Flares can generally be treated as point sources, but they require special handling since the emissions are generated outside of the "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 temperature is set to 20 meters per second (m/s), the stack height is the flare height plus flame length, and the stack diameter is based on the flare heat release rate. A conservative alternative that some applicants use is to ignore the flame length – which leads to a shorter stack height.

Agrium used the actual flare heights as the stack heights, which makes that aspect of their flare characterization conservative. However, they used a 121.92 m/s exit velocity for the **Plants 4 and 5 emergency flare (EU 23)** instead of the EPA recommended value of 20 m/s. Agrium stated in Section 7.1 of their modeling report that the exit velocity is based on vendor information, but they did not provide the vendor information to support their value.

The Department conducted a sensitivity analysis to help address the issue. The Department found that the maximum impact from the **EU 23** flare could triple when using EPA's 20 m/s exit velocity instead Agrium 121.92 m/s value. The point of

[9] Per Agrium's request, the Department included EUs 41B and 41C in the list of EUs that may have capped or horizontal stacks. These EUs only have VOC emissions. Therefore, a capped or horizontal release would have no effect on the NO_2, PM-10, PM-2.5, CO or NH_3 dispersion modeling analyses.

maximum impact changes as well. However, none of the points of maximum impact are near the points of maximum impacts found in the cumulative impact analyses. The **EU 23** flare actually has negligible influence on the maximum cumulative impacts. In the case of NH_3, reducing the exit velocity increased the maximum 8-hour impact by only 0.1 micrograms per cubic meter ($\mu g/m^3$). This is less than 0.005 percent of the 2,100 $\mu g/m^3$ AAAQS. Agrium's approach for characterizing the **EU 23** flare is therefore adequate. Therefore, while Agrium's value is technically questionable, the ramifications are moot.

5.8.4. Volume Source Parameters

Applicants must provide the release height, initial lateral dimension and initial vertical dimension for each volume source. The method for determining these parameters is described in Section 3.2.2.2 of the AERMOD User's Guide. Agrium used reasonable values for these parameters.

5.9. Pollutant Specific Considerations

The following pollutants warrant additional discussion.

5.9.1. Ambient NO_2 Modeling

The modeling of ambient NO_2 concentrations can sometimes be refined through the use of ambient air data or assumptions. Section 5.2.4 of the Guideline describes several approaches that may be considered in modeling the annual average NO_2 impacts. These approaches are also generally applicable in modeling the one-hour NO_2 impacts.

Agrium used the national default ambient NO_2-to-NOx ratio of 0.75, as provided in the Guideline, to enhance the estimated annual average NO_2 concentrations. This is an acceptable and commonly used technique.

Agrium used the Ozone Limiting Method (OLM) to enhance the estimated 1-hour NO_2 concentrations. OLM is an allowed option under the Guideline for estimating annual average NO_2 impacts, but EPA has not promulgated OLM as an approved option for estimating 1-hour NO_2 impacts. They have issued guidance, however, that describes how OLM could be used in a 1-hour NO_2 analysis.[10] The use of OLM is therefore reasonable, but warrants discussion.

5.9.1.1 EPA and Department Approval

The use of a non-Guideline modeling technique requires EPA and Department approval per 18 AAC 50.215(c)(2). EPA Region 10 and the Air Permits Program

[10] 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;* March 1, 2011.

Manager[11] both granted permission to use OLM for the KNO Restart project on August 20, 2014.

5.9.1.2 Public Comment

The use of a non-Guideline model is subject to public comment per Alaska's State Implementation Plan and 40 CFR 51.160(f)(2). The Department is therefore soliciting public comment regarding Agrium's use of OLM in the public notice for the preliminary permit decision.

5.9.1.3 In-Stack NO_2-to-NOx Ratio

The NOx emissions created during combustion are partly nitric oxide (NO) and partly NO_2. Additional NO_2 is created as an EU's exhaust mixes with atmospheric O_3.

The assumed NO_2-to-NOx in-stack ratio (ISR) is a variable that must be set for each EU that generates NOx emissions. Source-specific ISR data should be used to define this ratio when available. When source-specific data is not available, EPA's 1-hour NO_2 modeling guidance indicates an ISR of 0.5 may be used without justification for the purposes of modeling the one-hour NO_2 impacts. According to EPA, this value represents "a reasonable upper bound based on the available in-stack data."

Agrium utilized EPA's NO_2/NOx ISR Database[12] to obtain the ISR for each class of NOx emitting EU. The resulting values that Agrium used for both the KNO EUs and offsite EUs are:

- 0.30 for turbines;
- 0.22 for reciprocating engines;
- 0.10 for boilers;
- 0.50 for everything else.

The selected values are reasonable.

5.9.1.4 Ozone Data

OLM requires ambient O_3 data to determine how much of the NO is converted to NO_2. Agrium used concurrent hourly ozone data collected by the National Park Service (NPS) at their Clean Air Status and Trends Network (CASTNET) site in Denali National Park and Preserve. Agrium used interpolation to fill in missing data of five hours or less, and the five-year maximum ozone concentration based on month, day of week and hour of day to fill in larger data gaps.

[11] The Commissioner delegated his authority regarding the use of non-guideline models to the Air Permits Program Manager on June 3, 2008.
[12] http://www.epa.gov/ttn/scram/no2_isr_database.htm

Agrium compared the five-year average ozone concentration by month and hour of day to the March through July 2014 ozone data measured to date in their pre-construction monitoring effort. Agrium showed that the ozone concentration is generally higher at Denali than at Nikiski. The use of Denali ozone data therefore makes that aspect of their 1-hour NO_2 modeling approach conservative.

5.9.2. 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).[13] AERMOD is an acceptable model for performing near-field analysis of the direct emissions, but EPA has not developed a near-field model that includes the necessary chemistry algorithms for estimating the secondary impacts.

EPA has instead issued guidance as to how secondary formation could be accounted for in various PSD scenarios.[14] EPA described a two-by-two matrix where the direct emissions and precursor emissions are either above or below the PSD significant emission rate (SER) for those pollutants. In Agrium's case, the direct emissions and at least one of the precursor emissions (NOx) exceed the respective SER. In this situation, a qualitative approach, or a hybrid qualitative/quantitative approach, would generally be adequate for assessing the secondary impacts.

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 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 near-field, where the maximum direct impacts typically occur.

EPA further stated that representative ambient monitoring data could be used to address the secondary formation that occurs from existing sources in the ambient standard demonstration. The change in ambient concentrations subsequent to the PM-2.5 minor source baseline could likewise be used in the PM-2.5 increment demonstration, if available.

Agrium used their pre-construction PM-2.5 data as the background concentration in their PM-2.5 AAAQS demonstration (see the *Off-site Impacts* section of this report). The ambient data likely includes at least some secondary formation from the off-site sources. Agrium also compared their NOx and SO_2 pre-cursor emissions to the potential emissions from the nearby stationary sources. Agrium's NOx and SO_2 emissions are both just under six-percent of the total potential emissions. Agrium reasonably concluded that the increase in pre-cursor emissions is inconsequential, especially given

[13] The NOx and SO_2 emissions are also referred as "precursor emissions" in a PM-2.5 assessment.
[14] *Guidance for $PM_{2.5}$ Permit Modeling* (EPA-454/B-14-001); May 2014.

the wide margin of PM-2.5 compliance shown through their pre-construction monitoring effort (see Table 3 of this report).

The PM-2.5 minor source baseline date for the Cook Inlet Intrastate Air Quality Control Region is September 14, 2012. There is no local ambient monitoring data from that period that could be used to determine the change in PM-2.5 impact from the existing sources. However, most EUs at the off-site stationary sources are pre-baseline, and therefore, do not consume PM-2.5 increment. Agrium identified two EUs that are an exception. The EUs are two upgraded Solar turbines (EU 32A and 33A) listed in the current operating permit for the Tesoro Kenai Refinery (AQ0035TVP02). Agrium included the direct emissions from these turbines in the PM-2.5 increment analysis. The secondary PM-2.5 formation from just two EUs would likely be inconsequential.

5.10. Downwash

Downwash refers to conditions where structures influence the plume from an exhaust stack. Downwash can occur when a stack height is less than a height derived by a procedure called "Good Engineering Practice," 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. Agrium used the current version of BPIPPRM, version 04274, to determine the building profiles needed by AERMOD.

Agrium included downwash for their on-site EUs, as well as the urea/NH_3 ships. They also included downwash for the EUs at the two adjacent stationary sources: the Nikiski Generating Plant operated by Alaska Electric & Energy Cooperative (AE&EC) and the Kenai Liquid Natural Gas (LNG) plant operated by ConocoPhillips Alaska Natural Gas Corporation (CPANGC). They did not include downwash for the off-site diesel-fired well pump (EU 65) and the non-adjacent off-site stationary sources (see the *Off-site Impact* section of this report). Excluding downwash for more distant EUs is a common and acceptable practice.

The Department used a proprietary 3-D visualization program to review Agrium's characterization of the exhaust stacks and structures. This lead to questions regarding Agrium's characterization of the wharf structure, which Agrium adequately addressed in a sensitivity analysis that they provided on October 20th. Agrium's characterization of their other structures is likewise reasonable. BPIPPRM indicated that the exhaust stacks are within the Good Engineering Practice (GEP) stack height requirements.

5.11. Ambient Air Boundary

For the purposes of air quality modeling, *ambient air* means outside air to which the public has access. Ambient air typically excludes that portion of the atmosphere within a stationary source's boundary. Agrium used their fence line as the ambient air boundary for the onshore portion of the KNO facility. For the overwater portion, Agrium established the ambient boundary at 100-meters (m) beyond the wharf and moored vessel. The 100-m range is standard practice for Cook Inlet stationary sources. The range represents a common sense set-back distance for safely navigating around objects in Cook Inlet, which can have substantive drift rates due to the strong tidal currents. Agrium appropriately treated the shore-line and the portion of Cook Inlet that is under the conveyor as ambient air.

5.12. Receptor Grid

Agrium used a variety of receptor grids in their AERMOD modeling analysis. They used the following nested Cartesian grid around the KNO facility:

- 25-m along the ambient boundary;
- 25-m from the ambient boundary to a distance of 100-m;
- 50-m from 100 m to 500 m; and
- 100-m from 500 m to 3 km.

They also used a polar grid at 5 km intervals from 10 km to 50 km. They used the Cartesian grid to determine the maximum project and cumulative impacts. They used the polar grid as a worst-case estimate of the project impacts within Tuxedni and Denali Class I areas. They limited the polar grid to 50 km since that is the maximum acceptable range of AERMOD. Agrium's receptor grid has sufficient resolution and coverage to determine the maximum impacts.

5.13. Off-Site Impacts

The impact from neighboring (off-site) sources must be accounted for in a cumulative impact assessment. In accordance with Section 8.2.3 of the Guideline, "*…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 ambient monitoring data.

The off-site inventory and background concentration must be evaluated on a case-specific basis for each of the modeled pollutants. The data used to represent the background concentration must represent the non-modeled sources such as natural, area and long-range transport. Once the background concentration is determined, it is added to the modeled concentration to estimate the total ambient concentration.

Agrium appropriately included the two adjacent stationary sources, the Nikiski Generating Plant and the Kenai LNG plant, in their off-site inventory since they would obviously have significant concentration gradients in the vicinity of KNO. They also included the nearby Kenai Refinery operated by Tesoro Alaska Petroleum Company, and the Bernice Lake Power Plant operated by AE&EC. Including these nearby stationary sources is also appropriate. Agrium only included the increment consuming EUs from each off-site stationary source in the increment demonstrations. Since the major source baseline data varies by pollutant, the resulting off-site EU inventory also varied by pollutant in the increment analysis.

Agrium relied on background data to account for the impact from all other regional sources. They used their pre-construction data to represent the PM-10 and PM-2.5 background concentrations. This data provides a conservative estimate of the background concentration since it includes impacts from the Kenai Refinery – which was modeled.

Agrium used the pre-construction NO_2 and CO data collected by Union Oil Company of California (Unocal) at the Swanson River Field to represent the NO_2 and CO background concentrations. Unocal collected this PSD-quality data from May 1, 2008 through April 30, 2009. Agrium used the annual NO_2 concentration for the annual NO_2 background concentration and the maximum 1-hour and 8-hour CO concentrations for the 1-hour and 8-hour background concentrations. For the 1-hour NO_2 background concentration, Agrium removed all concentrations measured whenever the wind blowing from the Swanson River Field turbines. Removing these data points is appropriate. Unocal sited the monitor to measure the maximum impacts from the turbines, not as a regional background site. The Swanson River Field is also far enough away that the maximum measured impacts would grossly overstate the impacts near Agrium.[15] The turbine impacts from the KNO, Kenia LNG and Nikiski Generating Plant turbines are also already accounted for through modeling. Agrium did not take the effort to recalculate the annual NO_2 concentration, or cull the CO data by wind direction, since they had adequate margin of compliance for those pollutants and averaging periods to use overly conservative background concentrations.

Agrium further refined the 1-hour NO_2 background concentration by hour-of-day. Agrium used the 98th-percentile from each hour, which according to Appendix S of 40 CFR 50, would be the fifth-highest value when processing a subset of this size (201 – 250 data points). Agrium instructed AERMOD to include the applicable 1-hour NO_2 background concentration prior to determining the daily maximum 1-hour NO_2 concentrations. Agrium's approach is consistent with EPA's NO_2 modeling guidance.

5.14. Design Concentrations

EPA generally allows applicants to use modeled concentrations that are consistent with the form of the standard or increment. In all cases, applicants must compare the highest modeled concentration to the deterministic annual average standards, increments, SILs, and SMCs.

Agrium used the modeled concentrations calculated as indicated in Table 5 for comparison to the SMCs, AAAQS and Class II increments, as applicable. Their approach is consistent with EPA guidance.

[15] The Swanson River Field is roughly 20 km from KNO.

Table 5. Agrium's Approach for Determining The Modeled Design Concentrations

<table>
<tr><th>Pollutant</th><th>Avg. Period</th><th>SMC</th><th>AAAQS</th><th>Class II Increment</th></tr>
<tr><td rowspan="2">NO_2</td><td>1-hr</td><td>--</td><td>h8h</td><td>--</td></tr>
<tr><td>Annual</td><td colspan="3">HY</td></tr>
<tr><td rowspan="2">PM-10</td><td>24-hr</td><td>h1h</td><td>h6h</td><td>h2h</td></tr>
<tr><td>Annual</td><td rowspan="4">--</td><td>--</td><td>HY</td></tr>
<tr><td rowspan="2">PM-2.5</td><td>24-hr</td><td>h8h</td><td>h2h</td></tr>
<tr><td>Annual</td><td>M5A</td><td>HY</td></tr>
<tr><td rowspan="2">CO</td><td>1-hr</td><td rowspan="3">h2h</td><td rowspan="3">--</td></tr>
<tr><td>8-hr</td><td>h1h</td></tr>
<tr><td>NH_3</td><td>8-hr</td><td>--</td></tr>
</table>

Table Notes:
h1h = high, first-high.
h2h = high, second-high.
h6h = high, sixth-high *averaged over five years*.
h8h = high, eighth-high. For purposes of 1-hour NO_2, the "h8h" is the five-year average of the high, eighth-high of the daily maximum 1-hr 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.
M5A = maximum five-year average of the annual average concentrations.
-- = the limit/threshold does not exist.

5.15. AERMOD Results and Discussion

The following discussion provides the overall maximum impacts between all scenarios.

5.15.1. AAAQS Demonstration

The maximum modeled NO_2, PM-10, PM-2.5, CO and NH_3 impacts from Agrium's ambient standard demonstration is presented in Table 6. The background concentration, total impact, and respective ambient standard are also presented for comparison. The total modeled impacts are less than the respective AAAQS. Therefore, Agrium has demonstrated compliance with the AAAQS.

The maximum 1-hour NO_2 impact shown in Table 6 is associated with the urea ship loading scenario. The maximum impact occurs over water and is mostly due to the urea vessel – which is a secondary emissions source. The maximum 1-hour NO_2 impact during the NH_3 vessel loading scenario is 164 $\mu g/m^3$. It occurs between the KNO and Nikiski Generating Plant boundary. The highest onshore impacts at locations where the general public has access is only two-thirds of the AAAQS. The Department is therefore not imposing a post-construction monitoring requirement for 1-hour NO_2.

Table 6. Maximum Impacts Compared to the AAAQS

Pollutant	Avg. Period	Max. Modeled Conc ($\mu g/m^3$)	Bkgd Conc ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	AAAQS ($\mu g/m^3$)
NO_2	1-hr	177.7	*Included*	**178**	188
	Annual	14.2	13.2	**27**	100
PM-10	24-hr	17.5	58.5	**76**	150
PM-2.5	24-hr	6.1	8.0	**14**	35
	Annual	1.1	3.6	**5**	15 [a]
CO	1-hr	8,144.9	2,500	**10,645**	40,000
	8-hr	2,916.0	1,100	**4,016**	10,000
NH_3	8-hr	204.4	0.35	**205**	2,100

Table Note:

[a] As previously noted, the Department has not yet adopted EPA's revised annual average PM-2.5 standard of 12 $\mu g/m^3$. The total annual average PM-2.5 impact is nevertheless less than the annual average PM-2.5 NAAQS, as well as the annual average PM-2.5 AAAQS.

The Department previously required Agrium to conduct post-construction NH_3 monitoring to ensure their emissions did not violate the 8-hour NH_3 AAAQS. As shown in Table 6, the maximum impact is only 10-percent of the NH_3 AAAQS. The Department therefore finds no basis for re-imposing a post-construction NH_3 monitoring requirement.

The maximum impacts for all other pollutants and averaging periods are well below the applicable air quality standard. The Department therefore is not imposing a post-construction monitoring requirement for any of the other pollutants and averaging periods.

5.15.2. Class II Increment Demonstration

The maximum modeled NO_2, PM-10 and PM-2.5 near-field increment impacts are presented in Table 7, along with the respective Class II increment. In all cases, the maximum impact is less than the applicable Class II increment. Therefore, Agrium has demonstrated compliance with the Class II increments.

Table 7. Maximum Impacts Compared to the Class II Increments

Pollutant	Avg. Period	Max. Modeled Conc ($\mu g/m^3$)	Class II Increment ($\mu g/m^3$)
NO_2	Annual	7.7	25
PM-10	24-hr	21.5	30
	Annual	1.5	17
PM-2.5	24-hr	8.3	9
	Annual	1.1	4

6. CALPUFF CLASS I INCREMENT ANALYSIS

CALPUFF is an EPA-approved dispersion modeling system for source-receptor distances of 50 to several hundred kilometers. The Guideline describes CALPUFF as a, "multi-layer, multi-species non-steady-state puff dispersion modeling system that simulates the effects of time- and space-varying meteorological conditions on pollutant transport, transformation, and removal." The main components are the meteorological preprocessor, CALMET; the dispersion model, CALPUFF; and the post-processor, CALPOST. Agrium used the current regulatory version of each component: CALMET version 5.8.4; CALPUFF version 5.8.4; and CALPOST version 6.221.
CALMET generates time-dependent three-dimensional (3-D) meteorological fields in order to simulate plume dispersion over large distances. It will accept data from 3-D meteorological prognostic models, such as the fifth-generation Mesoscale Meteorological model (MM5).

Agrium used the 2002 – 2004 MM5 data previously developed by a group of Alaskan industrial sources in support of their Best Available Retrofit Technology (BART) assessments under 18 AAC 50.260. Agrium was one of the operators involved in developing the MM5 dataset. The group, frequently referred as the "Alaska BART coalition" (ABC), processed the MM5 data with the version of CALMET that was current at that time. Agrium used the current version of CALMET to reprocess the MM5 data. They appropriately used the same CALMET options as previously approved for the BART effort.

CALPUFF has numerous switches that must be evaluated for the given situation. Section 6.2.3 of the Guideline provides EPA's general recommendations for a long rang transport analysis. However, EPA has subsequently issued several guidance memorandums in response to various issues that have arisen over the past few years (e.g., CALPUFF version 5.8.4 has settings that have been added subsequent to EPA's promulgation of CALPUFF in 2003). Agrium used appropriate settings for their CALPUFF analysis.

EPA has never promulgated Class I SILs for most of the increment-consuming pollutants. The one exception was PM-2.5, which EPA promulgated in October 20, 2010. However, EPA later acknowledged that the regulatory language did not provide sufficient flexibility for permitting authorities to exercise discretion to conduct or require additional analysis. EPA therefore asked the District of Columbia Circuit Court to remand and vacate the Class I SILs, which the court did on January 22, 2013.

The Department is nevertheless allowing Agrium to use the vacated Class I PM-2.5 SILs for this project. Agrium's Q/d analysis indicates that the project is too small and distant to warrant broad and detailed assessments at the Class I areas. The purpose of the project impact analysis is therefore to further support this position of inconsequential impact, rather than to determine the degree of impact. Since the court only questioned the circumstances regarding the use of the SILs, not the SILs themselves, using the Class I PM-2.5 SILs in this type of assessment is reasonable.

While EPA has never promulgated Class I SILs for the other pollutants, they did propose Class I SILs in 1996. Agrium used the proposed NO_2 and PM-10 Class I SILs since they are the only known values for this type of assessment. The use of these values is reasonable, especially since the Q/d analysis already showed inconsequential impact.

The maximum modeled NO_2, PM-10 and PM-2.5 project increment impacts at the Tuxedni and Denali Class I areas are presented in Tables 8 – 9, respectively, along with the PM-2.5 and proposed Class I SILs. The Department is reporting the overall maximum impact from any meteorological data year or short-term scenario.

Table 8. Maximum Project Impacts at Tuxedni

Pollutant	Avg. Period	Max. Modeled Conc ($\mu g/m^3$)	Proposed Class I SIL ($\mu g/m^3$)
NO_2	Annual	0.006	0.1
PM-10	24-hr	0.17	0.3
	Annual	0.010	0.2
PM-2.5	24-hr	**0.16**	0.07
	Annual	0.009	0.06

Table 9. Maximum Project Impacts at Denali

Pollutant	Avg. Period	Max. Modeled Conc ($\mu g/m^3$)	Proposed Class I SIL ($\mu g/m^3$)
NO_2	Annual	0.001	0.1
PM-10	24-hr	0.039	0.3
	Annual	0.002	0.2
PM-2.5	24-hr	0.037	0.07
	Annual	0.002	0.06

Most of the project impacts are below the SIL. The 24-hour PM-2.5 impact at Tuxedni is the exception. Since that impact is above the SIL, Agrium conducted a 24-hour PM-2.5 Class I increment analysis at Tuxedni.

Agrium conducted a separate run of the off-site PM-2.5 increment consuming EUs, two Tesoro turbines. They then added the maximum impact with the maximum project impact. This is a conservative approach since it does not pair the impacts in time and space. The maximum combined impact, along with the Class I increment, is provided in Table 10. Agrium conducted the analysis for both PM-2.5 averaging periods, even though the annual average project impact was below the PM-2.5 SIL. In both cases, the maximum combined impact is well below the Class I increment.

Table 10. Class I Increment Impacts at Tuxedni

Pollutant	Avg. Period	Max. Combined Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)
PM-2.5	24-hr	0.161	2
	Annual	0.009	1

Agrium's CALPUFF modeling analysis demonstrates that the restart project will not cause or contribute to a violation of the NO_2, PM-10 and PM-2.5 Class I increments at either the Tuxedni or Denali Class I areas.

The Department is not imposing any permit conditions to protect the Class I increments since the impacts are so small. Therefore, Agrium would not need to reassess their Class I increment impacts if they make a subsequent request under 18 AAC 50.508(6) to revise an ambient condition of Construction Permit AQ0083CPT06. However, Agrium may need to reassess their Class I increment impacts if they make a future modification that triggers PSD.

7. OZONE IMPACTS

As discussed in the Introduction, O_3 is a triggered PSD-pollutant for this project. Agrium was therefore required to provide an O_3 source impact analysis, per 40 CFR 52.21(k).

O_3 is not usually emitted directly into the air, but is instead created in the atmosphere through chemical reactions involving NOx, VOCs and sunlight. It is inherently a regional pollutant, the result of chemical reactions between emissions from many sources over a period of hours or days, and over a large area.

EPA does not have a recommended modeling approach for assessing the O_3 impact from an individual stationary source. These impacts are generally smaller than what a regional O_3 model could accurately predict. In practice, it is very rare for states or EPA to require O_3 modeling from a PSD applicant. Most applicants instead provide a qualitative assessment of the expected impacts.

Agrium compared their O_3 precursor emissions to the precursor emissions from nearby stationary sources. These emissions are reiterated in Table 11 below.

Table 11. Comparison of O_3 Precursor Emissions

Stationary Source	Potential Emissions (tpy)	
	NOx	**VOC**
KNO	213	114
Tesoro Kenai Refinery	774	1,132
AE&EC Bernice Lake Power Plant	748	9
AE&EC Nikiski Generating Plant	695	79
CPANGC Kenai LNG Plant	1,513	312
Total Existing	***3,730***	***1,532***
KNO as Percent of Existing	6%	7%

Agrium then compared the percent-increase in emissions (which ranged from 6% to 7%) to the current margin of compliance with the O_3 AAAQS. Agrium used Denali O_3 data for this comparison since they were still collecting O_3 data when they submitted their ambient demonstration. Agrium showed that the percent increase in NOx and VOC emissions is less than the margin of compliance.

Agrium has since completed their O_3 monitoring effort. The Department has therefore revised Agrium's demonstration by using Agrium's maximum concentration instead of the maximum Denali concentration. The Department is also prorating the maximum measured concentration by the maximum increase in either NOx or VOC emissions. Since the maximum measured 8-hour O_3 concentration is 60 ppb, the maximum projected concentration is 64 ppb. This is less than the

75 ppb AAAQS. Therefore, the KNO restart project will not cause or contribute to a violation of the O_3 AAAQS.

8. ADDITIONAL IMPACT ANALYSES

Under 40 CFR 52.21(o), PSD applicants must assess the impact from the proposed project and associated growth on visibility, soils, and vegetation. The Department's findings regarding Agrium's approach for fulfilling these requirements are reported below.

8.1. 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 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.

As previously discussed, the FLMs did not request visibility assessments for the Tuxedni and Denali Class I areas. However, since the PSD rules require a visibility analysis, the Department asked Agrium to provide a plume blight analysis at 50km, which is the maximum range of VISCREEN.

Since there are no Class II visibility thresholds, VISCREEN compares the visibility impacts to the Class I thresholds. VISCREEN provides results for impacts located <u>inside</u> a Class I area and for impacts located <u>outside</u> 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 <u>inside</u> a Class I area. Alaska only has two integral vistas, both of which are associated with the Denali Class I area. Since the integral vistas are well beyond the 50 km range of VISCREEN, the Department informed Agrium that they only had to report the "inside" results.

Agrium used VISCREEN to estimate their worst-case plume blight. They appropriately assumed an ozone concentration of 40 parts per billion (ppb) and a "background visual range" of 250 km. The VISCREEN results exceed the Class I thresholds. The Department did not require Agrium to conduct a more rigorous visibility analysis since there are no plume blight thresholds for Class II areas.

8.2. 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. EPA has established what they refer as "secondary" NAAQS in order to protect public welfare. The term "welfare" is defined in Section 302(h) of the Clean Air Act to include "effects on soils, water, crops, vegetation ...” The AAAQS and NAAQS are identical, with one exception. Therefore, an analysis that demonstrates compliance with the AAAQS likewise demonstrates compliance with the secondary NAAQS. The exception regards the previously discussed annual average PM-2.5 AAAQS, which is out of date.

Agrium demonstrated that they can comply with the AAAQS and the annual PM-2.5 NAAQS. Therefore, their ambient analysis demonstrates that they will not have adverse soil or vegetation impacts. The maximum cumulative impacts for the PSD-triggered pollutants with secondary NAAQS are reiterated in Table 12.

Table 12. Maximum Total Impacts Compared to the Secondary NAAQS

Pollutant	Avg. Period	Total Impact ($\mu g/m^3$)	Secondary NAAQS ($\mu g/m^3$)
NO_2	Annual	**27**	100
PM-2.5	24-hour	**14**	35
	Annual	**5**	12
PM-10	24-hour	**76**	150
O_3	8-hour	**118**	147

8.3. Associated Growth Analysis

40 CFR 52.21(o)(2) requires PSD applicants to assess the impacts from general commercial, residential, industrial and other growth associated with the source or modification. Agrium stated some population growth may occur in the area due to the KNO restart. However, the growth would be a small fraction of the current population and therefore, the growth would not cause an adverse impact on air quality.

The Department agrees with Agrium's conclusion, but questions part of the underlying basis. Agrium supported their position by stating the number of employees (140) is approximately one percent of the total Kenai and Soldotna population (11,706). The ratio is numerically accurate, but it does not address the growth associated from employee families. The Department is not equipped to estimate population growth, but notes that even if each employee had a house-hold size of four, the total growth would only be five percent of the total population. This is still a small percentage of the total population. The general air emissions associated with this growth would also be spread-out throughout the various housing areas. Therefore, Agrium's conclusion seems reasonable, even if the associated growth is greater than what Agrium implied.

9. CONCLUSION

The Department reviewed Agrium's permit application for the KNO restart project and concluded the following:

1. Agrium's ambient demonstration satisfies the ***Source Impact Analysis*** requirements of 40 CFR 52.21(k). Agrium demonstrated that the NOx, 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, 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, PM-10 and PM-2.5 Class I and Class II increments.
2. Agrium appropriately used the models and methods required under 40 CFR 52.21(l) ***Air Quality Models***.
3. In addition to demonstrating compliance with the AAAQS and increments associated with the PSD-triggered pollutants, Agrium also demonstrated compliance with the State's NH_3 AAAQS.
4. Agrium conducted their modeling analysis in a manner consistent with the Guideline as required under 18 AAC 50.215(b)(1).
5. Agrium's project impact analysis and pre-construction data satisfies the ***Preapplication Analysis*** requirements of 40 CFR 52.21(m)(1).
6. Agrium adequately addressed the ***Additional Impact Analysis*** provisions in 40 CFR 52.21(o).

The Department developed conditions in Construction Permit AQ0083CPT06 to ensure Agrium complies with the AAAQS and increments. These conditions are *summarized* as follows.

General Ambient Air Conditions

- Agrium will need to:
  - Comply with the BACT limits in order to protect the NO_2, PM-10, PM-2.5, and CO AAAQS and Class II increments (as applicable);
  - Construct and maintain the stack heights shown in Table 4, to protect the AAAQS and Class II increments associated with the given EU; and
  - For all EUs listed in the permit with exhaust stacks, construct and maintain the stacks with vertical, uncapped releases to protect the NO_2, PM-10, PM-2.5, CO and NH_3 AAAQS and Class II increments (as applicable), except as noted below:
    - **EUs 13**, **41**, **41B**, **41C**, **47C**, **47D**, **60**, **61**, **65** and **66** may have horizontal releases;[16] and

[16] EUs 41B and 41C are only listed for clarity purposes since they do not emit NOx, PM-10, PM-2.5, CO or NH_3. These EUs only emit VOC emissions.

    - Agrium may use of flapper valve rain covers, or other similar designs, for any EU as long as the rain cover does not hinder the vertical momentum of the exhaust plume.

<u>Limits to Protect Annual AAAQS and Class II Increments</u>

- To protect the annual NO_2 AAAQS, the annual NO_2 Class II increment, the annual PM-10 Class II increment, the annual PM-2.5 AAAQS and the annual PM-2.5 Class II increment, Agrium will need to limit the annual operation of the EUs listed below:
  - **Solar Combustion Turbines (EUs 55 – 59)**: the total operation in bypass mode shall not exceed 204 hrs/yr;
  - **Startup Heater (EU 13)**: do not operate for more than 200 hrs/yr;
  - **Diesel Fired Well Pump (EU 65)**: do not operate for more than 168 hrs/yr; and
  - **Gasoline Fired Firewater Pump (EU 66)**: do not operate for more than 168 hrs/yr.

<u>Limits to Protect Short-term AAAQS and Class II Increments</u>

- To protect the 24-hour PM-10 AAAQS and Class II increment, and the 24-hour PM-2.5 AAAQS and increment, Agrium will need to limit the operation of the **Gasoline Fired Firewater Pump (EU 66)** to no more than four hours per day.
- To protect the 1-hour NO_2 AAAQS, the 1-hour and 8-hour CO AAAQS, the 24-hour PM-10 AAAQS and Class II increment, and the 24-hour PM-2.5 AAAQS and Class II increment, Agrium may not operate more than one **Solar Combustion Turbine (EU 55 – 59)** in bypass mode at a time.
- To protect the 1-hour NO_2 AAAQS, Agrium will need to limit the annual operation of the EUs listed below:
  - **Startup Heater (EU 13)**: do not operate for more than 200 hrs/yr;
  - **Diesel Fired Well Pump (EU 65)**: do not operate for more than 168 hrs/yr; and
  - **Gasoline Fired Firewater Pump (EU 66)**: do not operate for more than 168 hrs/yr.