Technical Analysis Report
For the terms and conditions of
Construction Permit AQ0083CPT07

Issued to Agrium U.S. Inc.

For the Kenai Nitrogen Operations

Alaska Department of Environmental Conservation
Air Permits Program

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Preliminary – November 20, 2020

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Abbreviations/Acronyms

AAC ....Alaska Administrative Code
AAAQS ....Alaska Ambient Air Quality Standards
Department ....Alaska Department of Environmental Conservation
BACT ....Best Available Control Technology
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 AQ0083CPT07 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, Nikiski, 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 May 21, 2019. 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 SoLoNOx for the turbines and selective catalytic reduction for the combination of the turbines and waste heat boilers, achieving 5 ppmv NOx at 15% O_2 for combined Solar Turbine/Waste Heat Boiler exhaust (approximately 0.027 lb/MMBtu NOx emission rate from the turbine and 0.008 lb/MMBtu from the waste heat boiler). 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 1,286 tons per year (tpy).

Agrium's application shows that the source's PTE hazardous air pollutants (HAPs) are 73.6 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.

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 AQ0083CPT07	215.6	764.5	176.7	174.3	172.9	121.3	10.2	2,197,970
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	**216**	**765**	**N/A**	**174**	**N/A**	**121**	**10**	**N/A**
	1,286							

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).

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

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 Section 3 of the permit.

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 C of this TAR.

4. PERMIT CONDITIONS

The bases for the standard and general conditions imposed in Construction Permit AQ0083CPT07 are described below.

Section 1: Emissions Unit Inventory

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

Section 2: Emission Fees

Condition 3, Fee Requirements

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

Conditions 4 and 5, Assessable Emissions

18 AAC 50.346(b)(1) requires the Department to include the Standard Permit Condition (SPC) I language for construction permits. However, for Construction Permit AQ0083CPT07, as indicated by Footnote 3, if the stationary source has not commenced construction or operation on or before March 31, the Permittee is required to submit a transmittal letter certified by the responsible official under 18 AAC 50.205 indicating that the assessable emissions for the source are zero for the previous fiscal year with an estimate of when construction will begin.

Section 3: State Emission Standards

Conditions 6 – 10, Visible Emissions

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

The Department is requiring an initial compliance demonstration within 60 days of startup of the new liquid fuel-fired EUs 65 and 66, as well as on going monitoring for the granulator scrubber exhaust vent stacks EUs 35 and 36. For the fuel gas-fired EUs 12, 13, 44a, and 48a through 59a, the Department is requiring a statement in each operating report that the EUs fired only fuel gas as fuel. For the flaring EUs 11, 22, and 23, the Department is requiring an initial Method 9 observation during the first daylight flare event.

Conditions 11, Particulate Matter (PM)

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

Experience has shown there is a correlation between opacity and particulate matter. 20 percent visible emissions would normally comply with the 0.05 gr/dscf. As such, compliance with opacity limits is included as a surrogate method of assuring compliance with the PM standards. The Department is requiring on going monitoring for the granulator scrubber exhaust vent stacks EUs 35 and 36. With the exception of the liquid fuel-fired pump engines EUs 65 and 66, all other fuel burning EUs at the stationary source will combust natural gas. Particulate emissions from the combustion of low sulfur natural gas is relatively insignificant. Therefore, the Department did not impose testing and MR&R conditions for these units, other than reporting that natural gas was the only fuel combusted in the EU during the reporting period.

Condition 12, Sulfur Compound Emissions

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

Calculations show that fuel oil with sulfur content less than 0.74 percent by weight will comply with the state emissions standard. Calculations show that fuel gas with sulfur content less than 4,000 parts per million by volume will comply with the state standards. 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.

Section 4: Ambient Air Quality Protection Requirements

Conditions 13 – 17

18 AAC 50.010 contains the ambient air quality standards (AAQS). 18 AAC 50.020 contains the maximum allowable increases (increment). The Department will include conditions to protect these standards when warranted. The Department determined that conditions are warranted to protect the 1-hour AAQS, annual AAQS, and annual increment for NO_2; 24-hour AAQS, 24-hour increment, and annual increment for PM-10; 24-hour AAQS, 24-hour increment, annual AAQS, and annual increment for PM-2.5; and the 1-hour and 8-hour AAQS for CO for the reasons described in Appendix C of this TAR.

Section 5: Best Available Control Technology

Conditions 18 – 31

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

Section 6: Federal Requirements

Conditions 32 – 45

Construction Permits typically do not include a Federal Requirements Section. However, the applicant requested that certain federal requirements be included in this construction permit AQ0083CPT07, as was done in the previous Construction Permit AQ0083CPT06. When Condition 52 is triggered and the Permittee is required to obtain a Title V Operating Permit, the Department will include all the applicable federal requirements at that time.

Conditions 32 through 40, NSPS Subpart A Requirements

Most affected facilities (with the exception of some storage tanks) subject to a New Source Performance Standards (NSPS) are subject to Subpart A. At this stationary source, EU 12 is subject to NSPS Subpart D, EUs 44a, 48a and 49a are subject to NSPS Subpart Db, and EUs 55a through 59a are subject to NSPS Subpart KKKK. Therefore, these EUs are all subject to Subpart A.

Conditions 32.1 – 32.3: The Permittee is required to comply with the notification requirements in 40 C.F.R. 60.7 (a)(1) - (4) for a new NSPS affected facility[2] or in the event of a modification or reconstruction of an existing facility.[3]

Condition 32.4: The requirements to notify the EPA and the Department of any proposed replacement of components of an existing facility (40 C.F.R. 60.15) apply in the event that the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility.

Condition 33: The requirements in 40 C.F.R. 60.7(b) to maintain start-up, shutdown, or malfunction records are applicable to all NSPS affected facilities subject to Subpart A.

Conditions 34 and 35: NSPS excess emission and monitoring systems performance report and summary report form in 40 C.F.R. 60.7(c) and (d) are applicable to an owner or operator required to or electing to install a continuous monitoring device to monitor EUs subject to an NSPS emissions standard. Excess emissions are defined in applicable subparts.

Condition 36: The Permittee is required to comply with the initial performance test requirements in 40 C.F.R. 60.8 for a new NSPS affected facility or in the event of modification or reconstruction of an existing facility into an affected facility or at such other times as may be required by EPA.

Condition 37: Good air pollution control practices in 40 C.F.R. 60.11 are applicable to most NSPS affected facilities subject to Subpart A, including EUs 12, 44a, 48a, and 48a through 59a.

Condition 38: The condition states that any credible evidence may be used to demonstrate compliance or to establish violations of relevant NSPS standards for EUs 12, 44a, 48a, and 48a through 59a.

Condition 39: Concealment of emissions prohibitions in 40 C.F.R. 60.12 are applicable to EUs 12, 44a, 48a, and 48a through 59a.

Condition 40: Monitoring requirements in 40 C.F.R. 60.13 are applicable to EUs 12, 44a, 48a, and 49a because a CMS is used to determine compliance with Subparts D and Db emission standards.

The flare is not subject to 40 C.F.R. 60.18 because it is a safety device and not a control device. It does not control emissions from any NSPS regulated emissions units.

Condition 41, NSPS 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

[2] *Affected facility* means, with reference to a stationary source, any apparatus to which a standard applies, as defined in 40 C.F.R. 60.2.

[3] *Existing facility* means, with reference to a stationary source, any apparatus of the type for which a standard is promulgated in this part, and the construction or modification of which was commenced before the date of proposal of that standard; or any apparatus which could be altered in such a way as to be of that type, as defined in 40 C.F.R. 60.2.

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 NOx emission limits found in:

40 CFR 60.44(a)(1)	40 CFR 60.46(b)	40 CFR 60.46(d)

Condition 42, NSPS 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 60.42b(k)(2)	40 CFR 60.44b(a)	40 CFR 60.45b(j)
40 CFR 60.46b(c)	40 CFR 60.48b(1)	40 CFR 60.49b(d)(1)
40 CFR 60.49b(g)		

Condition 43, NSPS Subpart KKKK - Standards of Performance for Stationary Combustion Turbines

This subpart applies to stationary combustion turbines that commenced construction, modification, or reconstruction after February 18, 2005, and have a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour based on higher heating value of the fuel. The source will contain five new 55.4 MMBtu/hr gas-fired combined cycle turbines with associated 46.7 MMBtu/hr waste heat boilers that must comply with the NOx and SO_2 emissions limits specified in:

40 CFR 60.4320	40 CFR 60.4330	Table 1 to Subpart KKKK of Part 60

Condition 44, NESHAP Subpart FFFF - Standards for Miscellaneous Organic Chemical Manufacturing

The KNO facility is required to comply with any applicable National Emission Standards for Hazardous Air Pollutants (NESHAP) requirements for miscellaneous organic chemical manufacturing contained in 40 CFR 63 Subpart FFFF.

Condition 45, NESHAP Subpart ZZZZ - 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 63 Subpart ZZZZ.

Section 7: General Recordkeeping and Reporting Requirements

Condition 46, Recordkeeping Requirements

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

Condition 47, Certification

18 AAC 50.205 requires the Permittee to certify any permit application, report, affirmation, or compliance certification submitted to the Department. This requirement is reiterated as a standard permit condition in 18 AAC 50.345(j).

Condition 48, Submittals

Condition 48 clarifies where the Permittee should send their reports, certifications, and other submittals required by the permit. The Department included this condition from a practical perspective rather than a regulatory obligation.

Condition 49, Information Requests

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

Condition 50, Excess Emission and Permit Deviation Reports

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

Condition 51, Operating Reports

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

Condition 52, Title V Major Source Application Submittal Date

For a stationary source that directly emits, or has the potential to emit, 100 tpy or more of any air pollutant subject to regulation, the Permittee shall file a complete application to obtain the part 70 Title V Operating Permit within 12 months after commencing operation or exceeding the 100 tpy threshold as required by 40 C.F.R. 70.5.

Condition 53, Reasonable Precautions to Prevent Fugitive Dust

This condition reiterates 18 AAC 50.045(d), which requires a person to use reasonable precautions when handling, storing or transporting bulk materials or engaging in an industrial activity. 18 AAC 50.045 is included in the SIP approved by EPA and, therefore, is an applicable requirement, per 40 C.F.R. 71.2 in operating permits. The Department included this condition in this construction permit because the Permittee produces urea, which is an emission unit or activity listed under Table 7 of 18 AAC 50.346(c). The Department used the language in SPC X for the permit. The condition requires the Permittee to take reasonable action to prevent particulate matter from being emitted into the ambient air in accordance with 18 AAC 50.045(d).

Condition 54, Air Pollution Prohibited

18 AAC 50.110 prohibits any emission which is injurious to human health or welfare, animal or plant life, or property, or which would unreasonably interfere with the enjoyment of life or property. Condition 54 reiterates this prohibition as a permit condition. The Department used the Standard Permit Condition II language for this construction permit.

Condition 55, Emission Inventory Reporting

This condition requires the Permittee to submit emissions data to the state, so the state is able to satisfy the federal requirement to submit emission inventory data from point sources to the EPA as required under 40 C.F.R. 51.15 and 51.321. The emission inventory requirement applies to sources defined as point sources in 40 C.F.R. 51.50. The state must report emissions data as described in 40 C.F.R 51.15 and the data elements in Tables 2a and 2b to Appendix A of 40 C.F.R. 51 Subpart A to EPA. 18 AAC 50.346(b)(8) requires the Department to include the SPC XV emission inventory language for construction permits.

Section 8: Standard Permit Conditions

Conditions 56 – 61

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

The Department included all of the minor/construction permit-related standard conditions of 18 AAC 50.345 in Construction Permit AQ0083CPT07. The Department incorporated these standard conditions as follows:

- 18 AAC 50.345(c)(1) and (2) is incorporated as Condition 56 of Section 8 (Standard Permit Conditions);
- 18 AAC 50.345(d) through (h) is incorporated as Conditions 57 through 61, respectively, of Section 8 (Standard Permit Conditions);
- As previously discussed, 18 AAC 50.345(i) is incorporated as Condition 49 and 18 AAC 50.345(j) is incorporated as Condition 47 of Section 7 (Recordkeeping, Reporting, and Certification Requirements); and
- 18 AAC 50.345(k) is incorporated as Condition 62, and 18 AAC 50.345(l) through (o) is incorporated as Conditions 66 through 70, respectively, of Section 9 (General Source Testing Requirements). See the following discussion.

Section 9: General Source Test Requirements

Conditions 62 – 70

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

- Condition 63 requires the Permittee to conduct their source tests under conditions that reflects the actual discharge to ambient air; and
- Condition 64 requires the Permittee to use specific EPA reference methods when conducting a source test.

Section 9 also includes the previously discussed standard conditions for source testing.

5. PERMIT ADMINISTRATION

Construction Permit AQ0083CPT07 rescinds and replaces Construction Permit AQ0083CPT06 upon issuance. Agrium U.S. Inc. may therefore operate in accordance with Construction Permit AQ0083CPT07 upon issuance.

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 and revised the ratings of the turbines and package boilers based on the May 21, 2019 application.

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

EU ID	Unit ID/Description	Hours	Maximum Rating or Capacity	NO_X & CO EF Units	NO_X		CO		VOC PM /PM-10/ PM-2.5 EF Units	VOC		PM-10		PM-2.5		SO_2	CO_2e
					EF	PTE (tpy)	EF	PTE (tpy)		EF	PTE (tpy)	EF	PTE (tpy)	EF	PTE (tpy)	PTE[8] (tpy)	PTE (1,000 tpy)
11	Ammonia Tank System Flare	8,760	1.25 MMBtu/hr	lb/MMBtu	0.068	0.37	0.31	1.70	lb/MMBtu	0.66	3.61	0.0075	0.041	0.0075	0.041	0.0032	0.012
12	Primary Reformer B-201	8,760	1350 MMBtu/hr	lb/MMBtu	0.02	118.26	0.043	251.88	lb/MMscf	5.5	31.88	7.6	44.06	7.6	44.06	3.48	699.78
13	Startup Heater B-200	200	101 MMBtu/hr	lb/MMscf	100	0.99	84	0.83	lb/MMscf	5.5	0.054	7.6	0.075	7.6	0.075	0.0059	1.20
14	CO_2 Vent D-207	8,760	90 tons/hr	lb/hr	-	-	2.9	12.70	lb/hr	11.4	49.9	-	-	-	-	-	845.49
15	Organic S Removal Vent H-205	1,248	1 24-hr regen/wk	-	-	-	-	-	tons/yr	0.01	0.010	-	-	-	-	-	-
16	Amine Fat Flasher Vent H-269	8,760	- -	lb/hr	-	-	1.05	4.60	lb/hr	0.22	0.96	-	-	-	-	-	13.74
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	126.90	-	-	-	-	-	-	-	-	-
22	Plants 4 and 5 Small Flare B-502	8,760	1.25 MMBtu/hr	lb/MMBtu	0.068	0.38	0.31	1.70	lb/MMBtu	0.66	3.61	0.0075	0.041	0.0075	0.041	0.0032	0.65
23	Plants 4 and 5 Emergency Flare B-501	8,760	0.4 MMBtu/hr	lb/MMBtu	0.068	0.20	0.31	0.54	lb/MMBtu	0.66	1.16	0.0075	0.013	0.0075	0.013	0.0010	0.21
35	Granulator A/B Scrubber Exhaust Vent C-560A	8,760	50 tons/hr	-	-	-	-	-	lb/ton	-	1.75	0.2	43.80	0.2	43.80	-	-
36	Granulator C/D Scrubber Exhaust Vent C-560B	8,760	50 tons/hr	-	-	-	-	-	lb/ton	-	1.75	0.2	43.80	0.2	43.80	-	-
37	Atmospheric Absorber Final Scrubber D-515	8,760	- -	-	-	-	-	-	lb/hr	0.022	0.10	-	-	-	-	-	0.073
38	Inerts Vent Scrubber D-511	8,760	- -	-	-	-	-	-	lb/hr	0.028	0.12	-	-	-	-	-	0.55
39	After Condenser Exchanger E-535	8,760	- -	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	Cooling Tower E-711	8,760	15,000 gal per min	-	-	-	-	-	lb/1000 gal	-	-	29.97% of PM	0.99	0.18% of PM	0.0059	-	-
41-41C	Tanks & Scrubber D-514, D-513, F-209, F-615	8,760	- -	-	-	-	-	-	lb/hr	tanks	0.002	-	-	-	-	-	-

44a	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	7.6	7.93	7.6	7.93	0.63	125.48
47	Urea Loading Wharf	8,760	1,000 tons/hr	-	-	-	-	-	lb/ton	-	-	0.0011	0.47	0.0004	0.16	-	-
47B	Urea Warehouse and Transfer Fugitives	8,760	1,000 tons/hr	-	-	-	-	-	lb/ton	-	-	0.0004	0.19	0.0002	0.066	-	-
47C	Urea Warehouse and Transfer Stack Emissions	8,760	1,000 tons/hr	-	-	-	-	-	lb/ton	-	-	0.0001	0.035	$3x10^{-5}$	0.012	-	-
47D	Urea Transfer to Loading Warf	8,760	1,000 tons/hr	-	-	-	-	-	lb/ton	-	-	0.0001	0.037	$3x10^{-5}$	0.013	-	125.48
48a	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	7.6	7.93	7.6	7.93	0.63	125.48
49a	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	7.6	7.93	7.6	7.93	0.63	24.22
50	Waste Heat Boiler B-705A	8,760	46.7 MMBtu/hr	lb/MMBtu	0.008	1.64	0.109	22.31	lb/MMscf	5.5	1.10	7.6	1.52	7.6	1.52	0.12	24.22
51	Waste Heat Boiler B-705B	8,760	46.7 MMBtu/hr	lb/MMBtu	0.008	1.64	0.109	22.31	lb/MMscf	5.5	1.10	7.6	1.52	7.6	1.52	0.12	24.22
52	Waste Heat Boiler B-705C	8,760	46.7 MMBtu/hr	lb/MMBtu	0.008	1.64	0.109	22.31	lb/MMscf	5.5	1.10	7.6	1.52	7.6	1.52	0.12	24.22
53	Waste Heat Boiler B-705D	8,760	46.7 MMBtu/hr	lb/MMBtu	0.008	1.64	0.109	22.31	lb/MMscf	5.5	1.10	7.6	1.52	7.6	1.52	0.12	24.22
54	Waste Heat Boiler B-705E	8,760	46.7 MMBtu/hr	lb/MMBtu	0.008	1.64	0.109	22.31	lb/MMscf	5.5	1.10	7.6	1.52	7.6	1.52	0.12	24.22
55a	Solar Turbine/Gen Set GGT-744A	8,760	55.4 MMBtu/hr	lb/MMBtu	0.027	10.21	0.109	26.47	lb/MMBtu	0.0021	0.51	0.0075	1.81	0.0075	1.81	0.83	26.98
56a	Solar Turbine/Gen Set GGT-744B	8,760	55.4 MMBtu/hr	lb/MMBtu	0.027	10.21	0.109	26.47	lb/MMBtu	0.0021	0.51	0.0075	1.81	0.0075	1.81	0.83	26.98
57a	Solar Turbine/Gen Set GGT-744C	8,760	55.4 MMBtu/hr	lb/MMBtu	0.027	10.21	0.109	26.47	lb/MMBtu	0.0021	0.51	0.0075	1.81	0.0075	1.81	0.83	26.98
58a	Solar Turbine/Gen Set GGT-744D	8,760	55.4 MMBtu/hr	lb/MMBtu	0.027	10.21	0.109	26.47	lb/MMBtu	0.0021	0.51	0.0075	1.81	0.0075	1.81	0.83	26.98
59a	Solar Turbine/Gen Set GGT-744E	8,760	55.4 MMBtu/hr	lb/MMBtu	0.027	10.21	0.109	26.47	lb/MMBtu	0.0021	0.51	0.0075	1.81	0.0075	1.81	0.83	26.98
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	1.00	0.95	0.22	lb/MMBtu	0.36	0.08	0.31	0.070	0.31	0.070	0.066	0.037
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	0.10	0.018	0.10	0.02	0.015	0.027
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	7.6	0.24	7.6	0.24	0.02	3.77
Total Potential to Emit Emissions						**215.6**		**764.5**			**121.3**		**174.3**		**172.9**	**10.2**	**2,198.0**

Table Notes:
Fuel Gas Heat Content: 1,020 Btu/scf
PM Emission Factor for Urea Loading Wharf is limited by the capacity of urea granulation plant and includes an 87.5 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: BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

1.0 Introduction

The Agrium US Inc's (Agrium's) Kenai Nitrogen Operations (KNO) facility triggered PSD requirements for oxides of nitrogen (NOx), carbon monoxide (CO), particulate matter (PM), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM-10), particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers (PM-2.5), volatile organic compounds (VOC), and greenhouse gases (GHG). This appendix includes the Department of Environmental Conservation's (Department's) review Agrium's Best Available Control Technology (BACT) analysis for NOx, CO, PM, PM-10, PM-2.5 (the Department will refer to PM, PM-10, and PM-2.5 collectively as particulates in this BACT analysis), VOC, and GHG for its technical accuracy and adherence to accepted engineering cost estimation practices.

2.0 BACT Evaluation

A BACT analysis is an evaluation of all available control options for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts. 40 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, particulates, VOC, and GHG, establish emission limits which represent BACT, and assess the level of monitoring, recordkeeping, and reporting (MR&R) requirements 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 Sulfur Removal Vent
16	Amine Fat Flasher Vent
17	PC Stripper Surge Tank Vent
19	H_2 Vent Stack (dry gas vent)
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

EU ID	Description of EU
41-41C	Tank Scrubber
47-47D	Urea and Ammonia Loading Wharf
44a, 48a, and 49a	Package Boilers
50 – 54	Waste Heat Boilers
55a – 59a	Solar Turbines / Generator 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, particulates, VOC, and GHG for the applicable equipment.

Step 1 Identify All Potentially Available Control Options

The Department identifies all available control options for the EUs and the pollutant under consideration. This includes technologies used throughout the world or emission reductions through the application of available control techniques, changes in process design, and/or operational limitations. To assist in identifying available controls, the Department reviews available controls listed on the Reasonably Available Control Technology (RACT), BACT, and Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC). The RBLC is an EPA database where permitting agencies nationwide post imposed BACT for PSD sources. It is usually the first stop for BACT research. In addition to the RBLC search, the Department used several search engines to look for emerging and tried technologies used to control NOx, CO, particulates, VOC, and GHG 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.

Step 5 Select BACT

To complete the BACT process, the Department must establish enforceable emissions limits for each subject emission unit at the source for each pollutant subject to review. If technological or economic limitations in the application of a measurement methodology to a particulate emissions unit would make an emissions limit infeasible, a design, equipment, work practice, operational standard, or combination thereof may be prescribed. Also the technology upon which the BACT emissions limit is based should be specified so that they are specific to the individual emissions unit subject to BACT review.

The Department reviewed Agrium's BACT analysis for the KNO Facility and made BACT determinations for NOx, CO, particulates, VOC, and GHG 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 plans to install three gas-fired package boilers rated at 243 MMBtu/hr each, and five gas-fired Solar GSC-4701 turbine generator sets rated at 55.4 MMBtu/hr each that will be operated in combination with five existing gas-fired waste heat boilers to make five turbine cogeneration systems. Additionally, the KNO facility has previously installed one 1,350 MMBtu/hr primary reformer, 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 in the last 10 years for the proposed EU types.

Table B-2: NOx BACT Determinations in RBLC

Description of NOx BACT	Cogeneration Gas Turbines	Primary Reformer	Package Boilers	Startup Heater	Flares	Pump Engines
Good Combustion Practices	1	2	3	3		25
Dry Low NOx / Low NOx Burners	4	2	20	20		
Selective Catalytic Reduction	1	14	1	1		
Non-Selective Catalytic Reduction		1				
Limit Hours of Operation			1	1		5

Description of NOx BACT	Cogeneration Gas Turbines	Primary Reformer	Package Boilers	Startup Heater	Flares	Pump Engines
Federal Emission Standards						5
Flare Work Practice Requirements					7	
Flare Minimization Plan					10	
No Control Specified			1	1	8	25
Total	**6**	**19**	**26**	**26**	**25**	**60**

3.1 NOx BACT for the Cogeneration Turbines (EUs 55a – 59a) with Waste Heat Boilers (EUs 50 – 54)

Possible NOx emission control technologies for the cogeneration turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 16.210: small combined cycle and cogeneration natural gas-fired combustion turbines (≤25 MW). The search results are summarized below:

NOx Controls for Small Combined Cycle and Cogeneration Gas-Fired Turbines		
Control Technology	**Number of Determinations**	**Emission Limits (ppmv @ 15% O_2)**
Selective Catalytic Reduction	1	7
Dry Low NOx	4	15 – 25
Good Combustion Practices	1	15

Step 1- Identify NOx Control Technologies for the Cogeneration Turbines

From research, the Department identified the following technologies as available for NOx control of gas-fired combined cycle and cogeneration combustion 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. The operating temperature of conventional SCR systems ranges from 400 degrees Fahrenheit (°F) to 800°F. High temperature SCR relies on special material reaction grids and can operate at higher temperature ranges between 700°F to 1,075°F. High temperature SCR is most frequently installed on simple cycle turbines. Depending on the overall NH_3-to-NOx ratio, removal efficiencies are generally 80 to 90 percent. The Department's search of the RBLC database located small combined cycle and cogeneration natural gas-fired combustion turbines using SCR as a control method for NOx emissions. Therefore, the Department considers SCR a feasible control technology for the small cogeneration gas-fired turbines.

(b) Selective Non-Catalytic Reduction (SNCR)
SNCR involves the non-catalytic decomposition of NOx in the flue gas to N2 and water using reducing agents such as urea or NH3. 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 NH3 process (trade name-Thermal DeNOx) requires a reaction temperature window of 1,600°F to 2,200°F. In the urea process (trade name–NOxOUT), 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 small cogeneration gas-fired turbines.

(c) Non-Selective Catalytic Reduction (NSCR)
NSCR simultaneously reduces NOx and oxidizes CO and hydrocarbons in the exhaust gas to N2, carbon dioxide (CO2), 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 NO2 to N2 at a temperature between 800°F and 1,200°F. NSCR requires a low excess O2 concentration in the exhaust gas stream to be effective because the O2 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 small cogeneration gas-fired 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 also increases CO emissions as it lowers the combustion temperature. Depending on baseline uncontrolled NOx levels, water or steam injection can reduce NOx by 60% or more. The Department considers water/steam injection a technically feasible control technology for the small cogeneration gas-fired turbines.

(e) Dry Low NOx (DLN)
Using DLN combustors (marketed under many similar names such as SoLoNOx or DLE) utilize multistage premix combustors where the air and fuel is mixed at a lean (high oxygen) fuel-to-air ratio. The excess air in the lean mixture acts as a heat sink, which lowers peak combustion temperatures and also ensures a more homogeneous mixture

avoiding localized "hot spots", both resulting in greatly reduced NOx formation rates. DLN combustors have the potential to reduce NOx emissions by 40 to 60%. Note that DLN is designed for natural gas-fired or dual-fuel fired units and is not effective in controlling NOx emissions from fuel oil-fired units. The Department considers DLN a technically feasible control technology for the small cogeneration gas-fired turbines.

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

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

(h) Good Combustion Practices (GCP) and Clean Fuel
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. GCPs and clean fuel is considered a technically feasible control option for the small cogeneration gas-fired turbines.

Step 2 - Eliminate Technically Infeasible NOx Control Options for Cogeneration Turbines
As explained in Step 1, SNCR, NSCR, SCONOX^{TM}, and XONON^{TM} are not feasible technologies to control NOx emissions from the cogeneration gas-fired turbines smaller than 25 MW.

Step 3 - Ranking of Remaining NOx Control Technologies for Cogeneration Turbines
The following control technologies have been identified and ranked for control of NOx from the cogeneration turbines:

(a) SCR & Water Injection (95% Control)
(b) SCR (70% - 90% Control)
(c) Water Injection (70% Control)
(d) DLN (40% - 60% Control)
(e) GCPs & Clean Fuel (Less than 40% Control)

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

RBLC Review
A review of similar units in the RBLC indicates selective catalytic reduction, dry low NOx burners, and good combustion practices are the principle NOx control technologies installed on small combined cycle and cogeneration gas-fired turbines.

Applicant Proposal
The applicant provided an economic analysis for the installation of water injection on the turbines (prior to the inclusion of SoLoNOx) 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	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Water Injection with SCR	2.4	7.6	$490,470	$93,000	$12,291
Capital Recovery Factor = 0.1424 (7% for a 10 year life cycle)					

The applicant contends that the economic analysis indicates the level of NOx reduction from water injection in conjunction with selective catalytic reduction does not justify the use of this combination of controls for the small cogeneration gas-fired turbines based on the excessive cost per ton of NOx removed per year.

The applicant proposes the following as BACT for NOx emissions from the small cogeneration gas-fired turbines:

(a) NOx emissions from the operation of the small cogeneration gas-fired turbines shall be controlled by a combination of SCR on the turbines and associated waste heat boilers and SoLoNOx on the turbines; and

(b) NOx emissions from the small cogeneration gas-fired turbines at the waste heat boiler outlet shall not exceed 5 ppmv at 15 percent oxygen (@ 15% O_2), equivalent to a NOx emission limit of 0.027 lb/MMBtu for the turbines and 0.008 lb/MMBtu for the waste heat boilers.

Department Evaluation of BACT for NOx Emissions from Cogeneration Turbines

The Department revised the cost analysis provided by Agrium to reflect the lower base emissions rate for NOx of 0.027 lb/MMBtu for the turbines after the addition of SoLoNOx, which the applicant proposed to lower emissions after submitting their economic analysis. Additional changes to the Department's analysis include equipment life revised to a 25 year lifespan, adjusted the baseline PTE to 10.21 tpy to account for the allowed 204 hours per year when the SCR system is bypassed, adjusted the interest rate to the current bank prime interest rate of 3.25%, reduced the control efficiency of the water injection system from 76% to 60%, which is the control efficiency listed for water-steam injection on natural gas-fired turbines in AP-42 Table 3.1-1, and included direct and indirect installation costs for the water injection system. A summary of the analysis for the cogeneration gas turbines is shown below:

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Water Injection with SCR and SoLoNOx	4.1	6.1	$882,840	$75,290	$12,291
Capital Recovery Factor = 0.0590 (3.25% for a 25 year life cycle)					

The Department's economic analysis indicates the level of NOx reduction does not justify the use of water injection in conjunction with SCR and SoLoNOx as BACT for the small cogeneration gas-fired combustion turbines.

Step 5 – Selection of NOx BACT for Cogeneration Turbines

The Department's finding is that BACT for NOx emissions from the cogeneration gas-fired combustion turbines rated at 25 MW or less is as follows:

(a) NOx emissions from EUs 55a – 59a and their associated waste heat boilers EUs 50 – 54 shall be controlled by operating and maintaining SCR at all times the units are in operation (except for the 204 hours per year allowed under the permit);

(b) NOx emissions from EUs 55a – 59a shall be controlled by operating and maintaining SoLoNOx control technology according to the manufacture's specifications, at all times the units are operating;

(c) NOx emissions from EUs 55a – 59a and their associated waste heat boilers EUs 50 – 54 shall not exceed 5 ppmv @ 15% O_2 averaged over a 3-hour period;

(d) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation; and

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

3.2 NOx BACT for the Primary Reformer (EU 12)

Possible NOx emission control technologies for the primary reformer were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years with the process name containing the word *reformer*. The search results were then filtered to include all relevant reformers with natural gas as the primary fuel input. The search results are summarized below:

NOx Controls for Reformer Furnaces		
Control Technology	**Number of Determinations**	**Emission Limits (lb/MMBtu)**
SCR + Low NOx Burners	7	0.0109 – 0.025
SCR	7	0.006 – 0.013
SNCR	1	0.0125
Low NOx Burners	2	0.2
Good Combustion Practices	2	0.095 – 0.19

Step 1 – Identify NOx Control Technologies for the Primary Reformer

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

(a) Selective Catalytic Reduction (SCR)
The theory of SCR was discussed in detail in the NOx BACT section 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 section 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. Therefore, the Department did not consider SNCR as a feasible control technology for the primary reformer.

(c) Low NOx Burners
The theory of LNBs (Dry Low NOx) was discussed in detail in the NOx BACT section 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 (GCP) and Clean Fuel
The theory of GCPs and clean fuel was discussed in detail in the NOx BACT section for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of NOx emissions. GCPs and clean fuel 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 Step 1, SNCR is not technically feasible to control NOx emissions from the primary reformer.

Step 3 – Ranking of 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.

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

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

RBLC Review
Most of the RBLC control method entries for reformer furnaces list the use of SCR or SCR in conjunction with 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
In the application for Construction Permit AQ0083CPT06 (received October 24, 2013), Agrium provided an economic analysis for 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	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR & LNB	73.4	36.2	$5,356,000	$909,860	$25,180

Capital Recovery Factor = 0.1424 (7% for a 10 year life cycle)

The applicant contends that the economic analysis indicates the level of NOx reduction from low NOx burners in conjunction with selective catalytic reduction does not justify the use of this combination of controls for the primary reformer based on the excessive cost per ton of NOx removed per year.

The applicant proposes the following as BACT for NOx emissions from the primary reformer:

(a) NOx emissions from the operation of the primary reformer shall be controlled by SCR;

(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; and

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

Department Evaluation of BACT for NOx Emissions from Primary Reformer
The Department revised the cost analysis provided by Agrium in their previous permit application to account for inflation at 8.51% that has occurred since 2013. Additionally, the Department increased the baseline potential to emit to 118.3 tpy and made changes to the analysis to reflect the equipment life revised to a 25 year lifespan and adjusted the interest rate to the current bank prime interest rate of 3.25%. A summary of the analysis for the primary reformer is shown below:

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR & LNB	79.2	39.0	$5,811,800	$502,950	$12,888
Capital Recovery Factor = 0.0590 (3.25% for a 25 year life cycle)					

The Department's economic analysis indicates the level of NOx reduction does not justify the use of low NOx burners in conjunction with SCR as BACT for the primary reformer.

Step 5 – Selection of NOx BACT for the Primary Reformer
The Department's finding is that BACT for NOx emissions from the primary reformer is as follows:

(a) NOx emissions from EU 12 shall be controlled by operating and maintaining SCR at all times the unit is in operation;

(b) NOx emissions from EU 12 shall not exceed 17 ppmvd at 3% oxygen (0.02 lb/MMBtu) averaged over 30-day period;

(c) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation; and

(d) 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 44a, 48a, and 49a)

Possible NOx emission control technologies for the package boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.310: Industrial Sized Natural Gas-Fired Boilers/Furnaces (>100 MMBtu/hr and <250 MMBtu/hr). The search results are summarized below:

NOx Controls for Industrial Sized Gas-Fired Boilers/Furnaces		
Control Technology	**Number of Determinations**	**Emission Limits (lb/MMBtu)**
Selective Catalytic Reduction	1	0.006
Low/Ultra-Low NOx Burners	20	0.01 - 0.1
Good Combustion Practices	3	0.06 – 0.119
Limited Use	1	0.098
No Control Specified	1	0.0085

Step 1 – Identify NOx Control Technologies for the Package Boilers

From research, the Department identified the following technologies as available for NOx control of gas-fired boilers/furnaces rated between 100 and 250 MMBtu/hr:

(a) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT section 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 section 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 gas-fired boilers and heaters rated between 100 and 250 MMBtu/hr installed at any facility. Therefore, the Department does not consider SNCR as a feasible control technology for the package boilers.

(c) Low NOx Burners
The theory of LNBs (Dry Low NOx) was discussed in detail in the NOx BACT section 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 (GCP) and Clean Fuel
The theory of GCPs and clean fuel was discussed in detail in the NOx BACT section for the turbines and will not be repeated here. Proper management of the combustion process

will result in a reduction of NOx. GCPs and clean fuel 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 Step 1, SNCR is not feasible to control NOx emissions from the package boilers. Additionally, the package boilers are used to generate steam for plant operations and therefore are not able to use limited operation as a possible control option.

Step 3 – Ranking of 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	(70 - 90% Control)
(b) ULNB	(50% - 90% Control)
(c) LNB	(40% - 60% Control)
(d) GCP & Clean Fuel	(Less than 40% Control)

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

RBLC Review
A review of similar units in the RBLC indicates low NOx burners, ultra-low NOx burners with flue gas recirculation, good combustion practices, limited operation, and SCR are the principle NOx control technologies installed on gas-fired boilers/furnaces rated between 100 and 250 MMBtu/hr.

Applicant Proposal
The applicant proposes the following as BACT for NOx emission from the package boilers:

(a) NOx emissions from the operation of the package boilers shall be controlled by SCR;
(b) NOx emissions from the package boilers shall not exceed 0.01 lb/MMBtu; and
(c) Compliance will be demonstrated through the use of a continuous emission monitoring system.

Step 5 – Selection of NOx BACT for the Package Boilers
The Department’s finding is that BACT for NOx emissions from the gas-fired boilers rated between 100 and 250 MMBtu/hr is as follows:

(a) NOx emissions from EUs 44a, 48a, and 49a shall be controlled by operating and maintaining SCR at all times the units are in operation;
(b) NOx emissions from EUs 44a, 48a, and 49a shall not exceed 0.01 lb/MMBtu averaged over a 30-day period;

(c) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation; and

(d) Compliance with the proposed emission limit will be demonstrated through the use of a continuous emission monitoring system.

3.4 NOx BACT for the Startup Heater (EU 13)

Possible NOx emission control technologies for the startup heater was obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.310: Industrial Sized Natural Gas-Fired Boilers/Furnaces (>100 MMBtu/hr and <250 MMBtu/hr). The search results are summarized below:

NOx Controls for Industrial Sized Gas-Fired Boilers/Furnaces		
Control Technology	**Number of Determinations**	**Emission Limits (lb/MMBtu)**
Selective Catalytic Reduction	1	0.006
Low/Ultra-Low NOx Burners	20	0.01 - 0.1
Good Combustion Practices	3	0.06 – 0.119
Limited Use	1	0.098
No Control Specified	1	0.0085

Step 1 – Identify NOx Control Technologies for the Startup Heater

From research, the Department identified the following technologies as available for NOx control of gas-fired boilers/furnaces rated between 100 and 250 MMBtu/hr:

(a) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. The startup heater is considered a limited use EU and has an existing limit of 200 hours per 12 consecutive month period. Therefore, the Department considers limited operation a technically feasible control technology for the startup heater.

(a) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT section 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 section 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 gas-fired boilers and heaters rated between 100 and 250 MMBtu/hr installed at any facility. Therefore, 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 section 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 (GCP) and Clean Fuel
The theory of GCPs and clean fuel was discussed in detail in the NOx BACT section for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of NOx emissions. GCPs and clean fuel 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 Step 1, SNCR is not a feasible technology to control NOx emissions from the startup heater.

Step 3 – Ranking of 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) Limited Operation	(94% Control)
(b) SCR	(70% - 90% Control)
(c) ULNB	(50% - 90% Control)
(d) LNB	(40% - 60% Control)
(e) GCP & Clean Fuel	(Less than 40% Control)

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

RBLC Review
A review of similar units in the RBLC indicates low NOx burners, ultra-low NOx burners with flue gas recirculation, good combustion practices, limited operation, and SCR are the principle NOx control technologies installed on gas-fired boilers/furnaces rated between 100 and 250 MMBtu/hr.

Applicant Proposal
In the application for Construction Permit AQ0083CPT06 (received October 24, 2013), Agrium provided an economic analysis for 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	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	3.6	32.6	$3,048,400	$2,174,200	$66,700
Capital Recovery Factor = 0.1424 (7% for a 10 year life cycle)					

The applicant contends that the economic analysis indicates the level of NOx reduction from selective catalytic reduction does not justify the use of this control for the primary reformer based on the excessive cost per ton of NOx removed per year.

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.

Department Evaluation of BACT for NOx Emissions from Startup Heater
The Department revised the cost analysis provided by Agrium in their previous permit application to account for inflation at 8.51% that has occurred since 2013. Additionally the Department made changes to the potential to emit to account for limited operation of 200 hours per year, revised the analysis to reflect the equipment life revised to a 25 year lifespan and adjusted the interest rate to the current bank prime interest rate of 3.25%. A summary of the analysis for the startup heater is shown below:

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.1	0.9	$3,306,600	$1,955,900	$2,195,200
Capital Recovery Factor =0.0590 (3.25% for a 25 year life cycle)					

The Department's economic analysis indicates the level of NOx reduction does not justify the use of SCR as BACT for the startup heater. Additionally, with a limit of 200 hours per year on the startup heater limiting potential NOx emissions to 1 tpy, no additional add-on controls will be cost effective.

Step 5 – Selection of NOx BACT for the Startup Heater
The Department's finding is that BACT for NOx emissions from the startup heater is as follows:

(a) NOx emissions from EU 13 shall be controlled by limiting operations of the EU to no more than 200 hours per 12 consecutive month period;

(b) NOx emissions from EU 13 shall not exceed 0.098 lb/MMBtu (AP-42 Table 1.4-1) averaged over 3-hour period;

(c) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation; and

(d) Compliance with the proposed limit will be demonstrated by monitoring, recording, and reporting the operating hours of EU 13.

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

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

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

Step 1 – Identify NOx Control Technologies for the Flares

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

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

(b) Flaring Minimization Plan
Flaring minimization plans define the procedures intended to reduce the frequency, magnitude, and duration of flaring events, without compromising plant operations or safety. By limiting the volume of gas going to the flare, all emissions types are minimized. The Department considers flaring minimization plans a technically feasible control 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 Step 1, flare gas recovery is not feasible to control NOx emissions from the flares.

Step 3 – Rank Remaining NOx Control Technologies for the Flares
Agrium has proposed the remaining two technically feasible control options for the flares EUs 11, 22, and 23. Therefore, ranking is not required.

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

Applicant Proposal
The applicant proposes the following as BACT for NOx emissions from the flares:

(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 Flares
The Department’s finding is that BACT for NOx emissions from the flares is as follows:

(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 (AP-42 Table 13.5-1, NOx for elevated flares) during normal operation, based on a three-hour average.

3.6 NOx BACT for the Well Pump and Fire Pump Engines (EUs 65 and 66)

Possible NOx emission control technologies for limited use internal combustion engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17:210: Small Fuel Oil-Fired Internal Combustion Engines (<500 hp) and 17:220: Small Other Liquid Fuel & Liquid Fuel Mixtures-Fired Internal Combustion Engines (<500 hp). The search results are summarized below:

NOx Controls for Small Diesel-Fired Engines		
Control Technology	**Number of Determinations**	**Emission Limits (g/hp-hr)**
Federal Emission Standards	5	2.2 – 4.8
Good Combustion Practices	25	2.0 – 9.5
Limited Operation	4	3.0
No Control Specified	25	2.6 – 5.6

NOx Controls for Small Gasoline-Fired Engines		
Control Technology	**Number of Determinations**	**Emission Limits (lb/MMBtu)**
Limited Operation	1	1.63

Step 1 – Identify NOx Control Technologies for the Pump Engines

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

(a) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. The pump engines are considered limited use EUs and both have existing permit limits of 168 hours per 12 consecutive month period. Therefore, the Department considers limited operation a technically feasible control technology for the pump engines.

(b) Selective Catalytic Reduction

The theory of SCR was discussed in detail in the NOx BACT section for the turbines and will not be repeated here. There were no instances of SCR used to control NOx emissions on small diesel or gasoline fired engines in the RBLC. Therefore, the Department considers SCR a technically infeasible control technology for the pump engines.

(c) Turbocharger and Aftercooler
Turbocharger technology involves the process of compressing intake air in a turbocharger upstream of the air/fuel injection. This process boosts the power output of the engine. The air compression increases the temperature of the intake air so an aftercooler is used to reduce the intake air temperature. Reducing the intake air temperature helps lower the peak flame temperature which reduces NOx formation in the combustion chamber. Today, manufacturers typically design new diesel engines with a turbocharger and aftercooler technology as part of standard equipment. The Department considers turbocharger and aftercooler a technically feasible control technology for the pump engines.

(d) Fuel Injection Timing Retard (FITR)
FITR reduces NOx emissions by the delay of the fuel injection in the engine from the time the compression chamber is at minimum volume to a time the compression chamber is expanding. Timing adjustments are relatively straightforward. The larger volume in the compression chamber produces a lower peak flame temperature. With the use of FITR the engine becomes less fuel efficient, particulate matter emissions increase, and there is a limit with respect to the degree the timing may be retarded because an excessive timing delay can cause the engine to misfire. The timing retard is generally limited to no more than three degrees. Diesel engines may also produce more black smoke due to a decrease in exhaust temperature and incomplete combustion. FITR can achieve up to 50 percent NOx reduction. Due to the increase in particulate matter emissions resulting from FITR, this technology will not be carried forward.

(e) Ignition Timing Retard (ITR)
ITR lowers NOx emissions by moving the ignition event to later in the power stroke, after the piston has begun to move downward. Because the combustion chamber volume is not at a minimum, the peak flame temperature is not as high, which lowers combustion temperature and produces less thermal NOx. Use of ITR can cause an increase in fuel usage, an increase in particulate matter emissions, and engine misfiring. ITR can achieve between 20 to 30 percent NOx reduction. Due to the increase in the particulate matter emissions resulting from ITR, this technology will not be carried forward.

(f) Federal Emission Standards
Federal emission standards require the engines meet the requirements of 40 C.F.R. 60 Subparts IIII and JJJJ, and 40 C.F.R 63 Subpart ZZZZ, or EPA tier certifications. Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. Subpart JJJJ applies to spark ignition internal combustion engines manufactured after various dates in the 2000s. EUs 65 and 66 are both manufactured prior to NSPS Subparts IIII and JJJJ and NESHAP Subpart

ZZZZ does contain NOx emission limits. Therefore the federal emission standards for NOx are not applicable to the pump engines.

(g) Good Combustion Practices (GCP) and Clean Fuel
The theory of GCPs and clean fuel was discussed in detail in the NOx BACT section for the turbines and will not be repeated here. The Department considers GCPs and clean fuel a technically feasible control technology for the pump engines.

Step 2 – Eliminate Technically Infeasible NOx Control Options for the Pump Engines
As explained in Step 1, The Department does not consider SCR, fuel injection timing retard, ignition timing retard, and federal emission standards as technically feasible to control NOx emissions from the pump engines.

Step 3 – Rank Remaining NOx Control Technologies for the Pump Engines
The following control technologies have been identified and ranked for control of NOx from the engines:

(a) Limited Operation	(94% Control)
(b) Good Combustion Practices	(Less than 40% Control)
(c) Turbocharger and Aftercooler	(6% – 12% Control)

Step 4 – Evaluate the Most Effective Controls
Limited operation is the most effective NOx control for small internal combustion engines. Since limited operation is not an add-on control, there is no additional environmental impacts.

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

Applicant Proposal
Agrium proposes to limit the operations of EUs 65 and 66 to no more than 168 hours each in any 12 consecutive month period as BACT for reducing NOx emissions.

Step 5 – Selection of NOx BACT for the Pump Engines
The Department's finding is that BACT for NOx emissions from the well pump and fire pump engines is as follows:

(a) Limit operation of EUs 65 and 66 to no more than 168 hours each, in any 12 consecutive month period;

(b) NOx emissions from the diesel-fired well pump engine EU 65 will not exceed 4.41 lb/MMBtu (AP-42 Table 3.3-1, NOx emissions for uncontrolled diesel engines);

(c) NOx emissions from the gasoline-fired fire pump engine EU 66 will not exceed 1.63 lb/MMBtu (AP-42 Table 3.3-1, NOx emissions for uncontrolled gasoline engines); and

(d) Compliance with the proposed limits will be demonstrated by recording and reporting operating hours for the pump engines.

4.0 BACT DETERMINATION FOR CO

The KNO facility plans to install three gas-fired package boilers rated at 243 MMBtu/hr each, and five gas-fired Solar GSC-4701 turbine generator sets rated at 55.4 MMBtu/hr each that will be operated in combination with five existing gas-fired waste heat boilers to make five turbine cogeneration systems. Additionally, the KNO facility has previously installed one 1,350 MMBtu/hr primary reformer, 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-3.

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 in the last 10 years for the proposed EU types.

Table B-3: CO BACT Determinations in RBLC

Description of CO BACT	Cogeneration Gas Turbines	Primary Reformer	Startup Heater	Package Boilers	Flares	Pump Engines	CO_2 & H_2 Vents
Good Combustion Practices & Clean Fuel	6	14	24	24		43	
Good Operating Practices							4
Oxidation Catalyst	1	1					
Proper Catalyst Selection							7
Limit Hours of Operation			1	1		3	1
Thermal Oxidizer							
Turbocharger & Intercooler						1	
Flare Work Practice Requirements					7		
Flare Minimization Plan					12		
No Control Specified			1	1	6	16	2
Total	**7**	**15**	**26**	**26**	**25**	**63**	**14**

4.1 CO BACT for the for the Cogeneration Turbines (EUs 55a – 59a) with Waste Heat Boilers (EUs 50 – 54)

Possible CO emission control technologies for the cogeneration turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 16.210: small combined cycle and cogeneration natural gas-fired combustion turbines (≤25 MW). The search results are summarized below:

CO Controls for Small Combined Cycle and Cogeneration Gas-Fired Turbines		
Control Technology	**Number of Determinations**	**Emission Limits**
Oxidation Catalyst	1	5 ppmv @ 15% O_2
Good Combustion Practices & Clean Fuel	6	0.03 – 0.037 lb/MMBtu 25 – 50 ppmv @ 15% O_2

Step 1- Identify CO Control Technologies for the Cogeneration Turbines

From research, the Department identified the following technologies as available for CO control of gas-fired combined cycle and cogeneration combustion turbines rated at 25 MW or less:

(a) Oxidation Catalyst
Catalytic oxidation is a flue gas control that oxidizes CO and hydrocarbon compounds to carbon dioxide and water vapor in the presence of a noble metal catalyst; no reaction reagent is necessary. The reaction is spontaneous and no reactants are required. Catalytic oxidizers can provide oxidation efficiencies of up to 90% at temperatures between 750°F and 1,000°F; the efficiency of the oxidation temperature quickly deteriorates as the temperature decreases. The Department's search of the RBLC database included small combined cycle and cogeneration natural gas-fired combustion turbines using oxidation catalysts to control CO emissions. Therefore, the Department considers oxidation catalysts a technically feasible control technology for the small cogeneration gas-fired turbines.

(b) Good Combustion Practices (GCP) and Clean Fuel
The theory of GCPs and clean fuel was discussed in detail in the NOx BACT section for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of CO. GCPs and clean fuel is considered a technically feasible control option for the small cogeneration gas-fired turbines.

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

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

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

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

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

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

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

Applicant Proposal
The applicant provided an economic analysis for the installation of an oxidation catalyst on the cogeneration 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	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.8	49.6	$1,924,900	$1,383,900	$28,700
Capital Recovery Factor = 0.1424 (7% for a 10 year life cycle)					

The applicant contends that the economic analysis indicates the level of CO reduction from an oxidation catalyst does not justify the use of an oxidation catalyst for the cogeneration turbines based on the excessive cost per ton of CO removed per year.

The applicant proposes the following as BACT for CO emissions from the small cogeneration gas-fired turbines:

(a) CO emissions from the operation of the cogeneration turbines shall be controlled with the use of good combustion practices.

(b) CO emissions from the turbines at the waste heat boiler outlet shall not exceed 50 ppmv at 15% oxygen, equivalent to a CO emission limit of 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.

Department Evaluation of BACT for CO Emissions from Cogeneration Turbines
The Department revised the cost analysis provided by Agrium to include CO and VOC emissions removed into one cost calculation, reflect the equipment life revised to a 25 year lifespan, adjusted the interest rate to the current bank prime interest rate of 3.25%, reduced the CO and VOC control efficiencies of the oxidation catalyst from 99% to 90% and 80% to 70% respectively. A summary of the analysis for the cogeneration gas turbines is shown below:

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	5.4	45.0	$1,924,900	$1,223,300	$27,167
Capital Recovery Factor = 0.0590 (3.25% for a 25 year life cycle)					

The Department's economic analysis indicates the level of CO and VOC reduction does not justify the use of an oxidation catalyst as BACT for the small cogeneration gas-fired combustion turbines based on the excessive cost per ton of CO and VOC emissions removed.

Step 5 – Selection of CO BACT for Cogeneration Turbines
The Department's finding is that BACT for CO emissions from the cogeneration gas-fired combustion turbines rated at 25 MW or less is as follows:

(a) CO emissions from EUs 55a – 59a and their associated waste heat boilers EUs 50 – 54 shall be minimized by burning clean fuel and by maintaining good combustion practices by following the manufacturer's operating and maintenance procedures at all times the units are in operation;

(b) CO emissions from EUs 55a – 59a and their associated waste heat boilers EUs 50 – 54 shall not exceed 50 ppmv @ 15% O_2 averaged over a 3-hour period; and

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

4.2 CO BACT for the Primary Reformer (EU 12)

Possible CO emission control technologies for the primary reformer were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years with the process name containing the word *reformer*. The search results were then filtered to include all relevant reformers with natural gas as the primary fuel input. The search results are summarized below:

CO Controls for Reformer Furnaces		
Control Technology	**Number of Determinations**	**Emission Limits**
Oxidation Catalyst	1	5 ppmv @ 3% O_2
GCPs and Clean Fuel	14	0.0194 – 0.0824 lb/MMBtu

Step 1 – Identify CO Control Technologies for the Primary Reformer

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

(a) Thermal Oxidizers
Thermal oxidizers have 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. Additionally, thermal oxidizers have not been installed on reformers at any facility listed in the RBLC. Therefore, the Department considers this technology technically infeasible for the reformer furnace.

(b) Oxidation Catalyst
The theory of oxidation catalysts was discussed in detail in the CO BACT section for the turbines and will not be repeated here. The Department identified one facility in the RBLC (MS-0092) with a steam methane reformer using an oxidation catalyst to control CO emissions. Therefore, the use of an oxidation catalyst is considered 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. The Department's research did not identify flares as a control technology used to control CO emissions from reformer furnaces installed at any facility. Therefore, the Department considers flaring as a technically infeasible control technology for the reformer furnace.

(d) Good Combustion Practices (GCP) and Clean Fuel
The theory of GCPs and clean fuel was discussed in detail in the NOx BACT section for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of CO. The majority of facilities in the RBLC are using good combustion practices to control CO emissions from reformer furnaces. Therefore, the use of GCPs and clean fuel is considered a technically feasible control option for the reformer furnace.

Step 2 – Eliminate Technically Infeasible CO Control Options for the Primary Reformer
As explained in Step 1, thermal oxidizers and flares are not feasible control technologies to reduce CO emissions from the reformer furnace.

Step 3 – Rank 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 (90% Control)
(b) GCPs & Clean Fuel (less than 90% Control)

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

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices is the principle CO control technology used for reformer furnaces. However, there is one facility in the RBLC (MS-0092) with a steam methane reformer using an oxidation catalyst to control CO emissions.

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	2.5	249.4	$7,120,300	$4,032,500	$16,200
Capital Recovery Factor = 0.1424 (7% for a 10 year life cycle)					

The applicant contends that the economic analysis indicates the level of CO reduction from an oxidation catalyst does not justify the use of an oxidation catalyst for the primary reformer based on the excessive cost per ton of CO removed per year.

The applicant proposes the following as BACT for CO emissions from the primary reforer:

(a) CO emissions from the primary reformer shall not exceed 43.45 lb/MMscf (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.

Department Evaluation of BACT for CO Emissions from Primary Reformer
The Department revised the cost analysis provided by Agrium to include CO and VOC emissions removed into one cost calculation, reflect the equipment life revised to a 25 year lifespan, adjusted the interest rate to the current bank prime interest rate of 3.25%, reduced the CO and VOC control efficiencies of the oxidation catalyst from 99% to 90% and 80% to 70% respectively. A summary of the analysis for the cogeneration gas turbines is shown below:

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	34.8	249.0	$7,120,300	$3,437,100	$15,200
Capital Recovery Factor = 0.0590 (3.25% for a 25 year life cycle)					

The Department's economic analysis indicates the level of CO and VOC reduction does not justify the use of an oxidation catalyst as BACT for the primary reformer based on the excessive cost per ton of CO and VOC emissions removed.

Step 5 – Selection of CO BACT for the Primary Reformer
The Department finding is that BACT for CO emissions from the primary reformer is as follows:

(a) CO emissions from the primary reformer (EU 12) shall not exceed 0.043 lb/MMBtu (43.45 lb/MMscf) averaged over a 3-hour period;

(b) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation; and

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

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

Possible CO emission control technologies for the package boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.310: Industrial Sized Natural Gas-Fired Boilers/Furnaces (>100 MMBtu/hr and <250 MMBtu/hr). The search results are summarized below:

CO Controls for Industrial Sized Gas-Fired Boilers/Furnaces		
Control Technology	**Number of Determinations**	**Emission Limits (lb/MMBtu)**
GCPs and Clean Fuel	24	0.01 – 0.084
Limited Use	1	0.082
No Control Specified	1	0.075

Step 1 – Identify CO Control Technologies for the Package Boilers

From research, the Department identified the following technologies as available for CO control for package boilers:

(a) Oxidation Catalyst
The theory of oxidation catalysts was discussed in detail in the CO BACT section for the turbines and will not be repeated here. The Department's search of the RLBC database did not identify any oxidation catalysts used as a CO control device for gas-fired boilers rated at less than 250 MMBtu/hr. Therefore, the Department does not consider oxidation catalysts to be a technically feasible control technology for the package boilers.

(b) Good Combustion Practices (GCP) and Clean Fuels
The theory of good combustion practices was discussed in detail in the NOx BACT section for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of CO. GCPs and clean fuel is considered a feasible control option for the package boilers.

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

As explained in Step 1, an oxidation catalyst is not feasible to control CO from the package boilers. Additionally, the package boilers are used to generate steam for plant operations and therefore are not able to use limited operation as a possible control option.

Step 3 – Rank Remaining CO Control Technologies for the Package Boilers

The applicant has proposed the only feasible control option for the package boilers. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls

According to the RBLC, good combustion practices and clean fuel are the applicable controls for CO emissions for the package boilers. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review

A review of similar units in the RBLC indicates good combustion practices and burning clean fuel, as well as limited operation are the principle CO control technologies installed on gas-fired boilers/furnaces rated between 100 and 250 MMBtu/hr.

Applicant Proposal

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.4	39.0	$2,277,900	$1,747,300	$44,800
Capital Recovery Factor = 0.1424 (7% for a 10 year life cycle)					

The applicant contends that the economic analysis indicates the level of CO reduction from an oxidation catalyst does not justify the use of an oxidation catalyst for the package boilers based on the excessive cost per ton of CO removed per year.

The applicant proposes the following as BACT for CO emissions from the package boilers:

(a) CO emissions from the package boilers shall not exceed 50 ppmv at 3% O_2 (0.037 lb/MMBtu);

(b) CO emissions from the package boilers shall be controlled by maintaining good combustion practices; and

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

Department Evaluation of BACT for CO Emissions from Package Boilers

The Department revised the cost analysis provided by Agrium to include CO and VOC emissions removed into one cost calculation, reflect the equipment life revised to a 25 year lifespan, adjusted the interest rate to the current bank prime interest rate of 3.25%, reduced the CO and VOC control efficiencies of the oxidation catalyst from 99% to 90% and 80% to 70% respectively. A summary of the analysis for the package boilers is shown below:

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	5.6	39.4	$2,277,900	$1,557,200	$39,498
Capital Recovery Factor = 0.0590 (3.25% for a 25 year life cycle)					

The Department's economic analysis indicates the level of CO and VOC reduction does not justify the use of an oxidation catalyst as BACT for the package boilers based on the excessive cost per ton of CO and VOC emissions removed.

Step 5 – Selection of CO BACT for the Package Boilers

The Department's finding is that BACT for CO emissions from the package boilers rated between 100 and 250 MMBtu/hr is as follows:

(a) CO emissions from EUs 44a, 48a, and 49a shall be controlled by maintaining good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation;

(b) CO emissions from EUs 44a, 48a, and 49a shall not exceed 50 ppmvd (0.037 lb/MMBtu) averaged over a 3-hour period; and

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

4.4 CO BACT for the Startup Heater (EU 13)

Possible CO emission control technologies for the startup heater was obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.310: Industrial Sized Natural Gas-Fired Boilers/Furnaces (>100 MMBtu/hr and <250 MMBtu/hr). The search results are summarized below:

CO Controls for Industrial Sized Gas-Fired Boilers/Furnaces		
Control Technology	**Number of Determinations**	**Emission Limits (lb/MMBtu)**
GCPs and Clean Fuel	24	0.01 – 0.084
Limited Use	1	0.082
No Control Specified	1	0.075

Step 1 – Identification of CO Control Technologies for the Startup Heater

From research, the Department identified the following technologies as available for CO control of startup heaters:

(a) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. The startup heater is considered a limited use EU and has an existing limit of 200 hours per 12 consecutive month period. Therefore, the Department considers limited operation a technically feasible control technology for the startup heater.

(b) Oxidation Catalyst
The theory of oxidation catalysts was discussed in detail in the CO BACT section for the turbines and will not be repeated here. The Department's search of the RLBC database did not identify any oxidation catalysts used as a CO control device for gas-fired boilers rated at less than 250 MMBtu/hr. Therefore, the Department does not consider oxidation catalysts to be a technically feasible control technology for the startup heater.

(c) Good Combustion Practices (GCP) and Clean Fuels
The theory of good combustion practices was discussed in detail in the NOx BACT section for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of CO. GCPs and clean fuel is considered a feasible control option for the startup heater.

Step 2 – Eliminate Technically Infeasible CO Control Options for the Startup Heater
As explained in Step 1, an oxidation catalyst is not a feasible control technology to reduce CO emissions from the startup heater

Step 3 – Rank Remaining CO Control Technologies for the Startup Heater
The applicant has proposed the only feasible control option for the startup heater. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
According to the RBLC, good combustion practices and clean fuel are the applicable controls for CO emissions for the startup heater. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates good combustion practices and burning clean fuel, as well as limited operation are the principle CO control technologies installed on gas-fired boilers/furnaces rated between 100 and 250 MMBtu/hr.

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); and

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

Step 5 – Selection of CO BACT for the Startup Heater
The Department's finding is that BACT for CO emissions from the startup heater is as follows:

(a) CO emissions from EU 13 shall be controlled by limiting operations of the EU to no more than 200 hours per 12 consecutive month period;

(b) CO emissions from EU 13 shall not exceed 0.082 lb/MMBtu (AP-42 Table 1.4-1) averaged over 3-hour period;

(c) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation; and

(d) Compliance with the proposed limit will be demonstrated by monitoring, recording, and reporting the operating hours of EU 13.

4.5 CO BACT for the Ammonia Tank Flare and Small Flares (EUs 11, 22, and 23)
Possible CO emission control technologies for the flares were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 19: Miscellaneous combustion (19:300 is specific to flares) and 50: Petroleum/Natural Gas Production and Refining. The search results were then filtered to include only emissions units with flares. The search results are summarized below:

CO Controls for Flares		
Control Technology	**Number of Determinations**	**Emission Limits (lb/MMBtu)**
Flare Work Practice Requirements	7	0.08 - 0.37
Flaring Minimization Plan	12	0.31 – 0.37
No Control Specified	6	0.082 – 0.37

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

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

(b) Flaring Minimization Plan
Flaring minimization plans define the procedures intended to reduce the frequency, magnitude, and duration of flaring events, without compromising plant operations or safety. By limiting the volume of gas going to the flare, all emissions types are minimized. The Department considers flaring minimization plans a technically feasible control 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 Step 1, flare gas recovery is not feasible to control CO emissions from the flares.

Step 3 – Rank Remaining CO Control Technologies for the Flares
Agrium has proposed the remaining two technically feasible control options for the flares EUs 11, 22, and 23. Therefore, ranking is not required.

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

Applicant Proposal
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 Flares
The Department's finding is that BACT for CO emissions from the flares is as follows:

(a) Venting to the ammonia tank flare EU 11, small flare EU 22, 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 0.31 lb/MMBtu (AP-42 Table 13.5-2, 02/18, CO for elevated flares) during normal operation, based on a three-hour average.

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

Possible CO emission control technologies for limited use internal combustion engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17:210: Small Fuel Oil-Fired Internal Combustion Engines (<500 hp) and 17:220: Small Other Liquid Fuel & Liquid Fuel Mixtures-Fired Internal Combustion Engines (<500 hp). The search results are summarized below:

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

CO Controls for Small Gasoline-Fired Engines		
Control Technology	**Number of Determinations**	**Emission Limits (lb/MMBtu)**
Limited Operation	1	0.99

Step 1 – Identify CO Control Technologies for the Pump Engines

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

(a) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. The pump engines are considered limited use EUs and both have existing permit limits of 168 hours per 12 consecutive month period. Therefore, the Department considers limited operation a technically feasible control technology for the pump engines.

(b) Oxidation Catalyst
The theory of oxidation catalysts was discussed in detail in the CO BACT section for the turbines and will not be repeated here. The Department's search of the RLBC database did not identify any oxidation catalysts used as a CO control device for small diesel or gasoline-fired engines. Therefore, the Department does not consider oxidation catalysts to be a technically feasible control technology for the pump engines.

(c) Good Combustion Practices (GCP) and clean fuel
The theory of GCPs and clean fuel was discussed in detail in NOx BACT section for the turbines and will not be repeated here. The Department's search of the RLBC database indicated that GCPs and clean fuel are commonly used to control CO emissions for small diesel and gasoline-fired engines. Therefore, the Department considers GCPs and clean fuel to be a technically feasible control technology for the pump engines.

(d) Federal Emission Standards
Federal emission standards require the engines meet the requirements of 40 C.F.R. 60 Subparts IIII and JJJJ, and 40 C.F.R 63 Subpart ZZZZ, or EPA tier certifications. Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. Subpart JJJJ applies to spark ignition internal combustion engines manufactured after various dates in the 2000s. EUs 65 and 66 are both manufactured prior to NSPS Subparts IIII and JJJJ, and NESHAP Subpart ZZZZ does contain CO emission limits for emergency engines at area sources of hazardous air pollutants (HAPs). Therefore the federal emission standards for CO are not applicable to the pump engines.

Step 2 – Eliminate Technically Infeasible CO Control Options for the Pump Engines
As explained in Step 1, The Department does not consider oxidation catalysts and federal emission standards as technically feasible to control CO emissions from the pump engines.

Step 3 – Rank Remaining CO Control Technologies for the Pump Engines
The applicant has proposed the only feasible remaining control options. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
Limited operation is the most effective CO control for small internal combustion engines. Since limited operation is not an add-on control, there is no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates good combustion practices, limited operation, and federal emission standards are the principle CO control technologies for both diesel-fired and gasoline-fired pump engines.

Applicant Proposal
The applicant proposes the following as BACT for CO emissions from the pump engines:

(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 EU 65 shall not exceed 0.95 lb/MMBtu;
(c) CO emissions from the gasoline-fired fire water pump EU 66 shall not exceed 0.99 lb/MMBtu; and
(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's finding is that BACT for CO emissions from the well pump and fire pump engines is as follows:

(a) Limit operation of EUs 65 and 66 to no more than 168 hours each, in any 12 consecutive month period;

(b) CO emissions from the diesel-fired well pump engine EU 65 will not exceed 0.95 lb/MMBtu (AP-42 Table 3.3-1, CO emissions for uncontrolled diesel engines);

(c) CO emissions from the gasoline-fired fire pump engine EU 66 will not exceed 0.99 lb/MMBtu (AP-42 Table 3.3-1, CO emissions for uncontrolled gasoline engines); and

(d) Compliance with the proposed limits will be demonstrated by recording and reporting operating hours for the pump engines.

4.7 CO BACT for the CO_2 Vent (EU 14)

Possible CO emission control technologies for the CO_2 vent were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 61.012: fertilizer production and 62.999: other inorganic chemical manufacturing. The search results were then filtered to include all relevant CO_2 vents. The search results are summarized below:

CO Controls for CO_2 Vent		
Control Technology	**Number of Determinations**	**Emission Limits (lb/hr)**
Thermal Oxidation & Proper Catalyst Selection	7	1.17 – 5.59
Good Operating Practices	4	1.17 – 2.83
No Control Specified	1	3.11

Step 1 – Identify CO Control Technologies for the CO_2 Vent

From research, the Department has identified the following control technologies as available for CO control of the CO_2 purification process.

(a) Proper Selection of Process Catalyst & Good Operating Practices
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 – Rank Remaining CO Control Technologies for the CO_2 Vent

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

Step 4 – Evaluate the Most Effective Controls

Proper selection of a catalyst will reduce CO emissions from the CO_2 vent while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary.

RBLC Review

A review of similar units in the RBLC indicates that proper catalyst selection for the conversion of CO to CO_2 and good operating practices are the principle CO control technologies used for CO_2 vents at similar sources.

Applicant Proposal
Agrium proposes to limit CO emissions from the CO_2 Vent EU 14 by use of good operational practices including the selection of an optimal process catalyst, with CO emissions limited to 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's finding is that BACT for CO emissions from the CO_2 vent is as follows:

(a) CO emissions from the CO_2 vent EU 14 shall be controlled by operating and maintaining a catalyst at all times the EU is in operation; and

(a) CO emissions from the CO_2 vent EU 14 shall not exceed 2.9 lb/hr averaged over a 3-hour period at 100% venting;

4.8 CO BACT for the H_2 Vent (EU 19)

Possible CO emission control technologies for the H_2 vent were obtained from the RBLC. The RBLC was searched for all determinations in the last 20 years with the process name containing the words *H_2 vent* or *hydrogen vent*. The search results are summarized below:

CO Controls for H2 vent		
Control Technology	**Number of Determinations**	**Emission Limits**
Limited Use (KNO's previous permit)	1	200 hours/year & 15,222 lb/startup
No Control Specified	1	None specified

Step 1 – Identify CO Control Technologies for the H_2 Vent
From research, the Department identified the following control technologies as available for CO control of 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
Limiting the operation of emissions units reduces the potential to emit of those units. The H_2 vent is considered a limited use EU and has an existing limit of 200 hours per 12 consecutive month period. Therefore, the Department considers limited operation a technically feasible control technology for the H_2 vent.

(c) Oxidation Catalyst
The theory of catalytic oxidation was discussed in detail in the CO BACT section for the turbines 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, an oxidation catalyst, and limited use are all technically feasible options for controlling CO from the H_2 vent. Therefore, none are eliminated.

Step 3 – Rank Remaining CO Control Technologies for the H_2 Vent

(a) Limited Operation (97% Control)
(b) Flaring (90% Control)
(c) Oxidation Catalyst (90% Control)

Step 4 – Evaluate the Most Effective Controls
Limited operation is the most effective CO control for a hydrogen vent. Since limited operation is not an add-on control, there is no additional environmental impacts.

RBLC Review
The only control listed in the RBLC for a hydrogen vent is limited operation.

Applicant Proposal
Agrium proses that BACT for the H_2 vent is limiting the operation of the EU to no more than 200 hours per 12 consecutive month period and that CO emissions shall not exceed 15,222 pounds during startup.

Step 5 – Selection of CO BACT for the H_2 Vent
The Department's finding is that BACT for CO emissions from the H_2 vent is as follows:

(a) CO emissions from the H_2 vent EU 19 shall be controlled by limiting operations of the EU to no more than 200 hours per 12 consecutive month period; and

(b) CO emissions from the H_2 vent EU 19 shall not exceed 15,222 pounds per startup.

5.0 BACT DETERMINATION FOR VOC

The KNO facility to install three gas-fired package boilers rated at 243 MMBtu/hr each, and five gas-fired Solar GSC-4701 turbine generator sets rated at 55.4 MMBtu/hr each that will be operated in combination with five existing gas-fired waste heat boilers to make five turbine cogeneration systems. Additionally, the KNO facility has previously installed one 1,350 MMBtu/hr primary reformer, 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-4.

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 in the last 10 years for the proposed EU types.

Table B-4: VOC BACT Determinations in RBLC

Description of VOC BACT	Cogeneration Gas Turbines	Primary Reformer	Startup Heater	Package Boilers	Flares	Pump Engines	CO_2 Vent	Storage Tanks	Urea Granulation Line
Good Combustion Practices & Clean Fuel	6	12	19	19		13			
Good Operating Practices							3		

Description of VOC BACT	Cogeneration Gas Turbines	Primary Reformer	Startup Heater	Package Boilers	Flares	Pump Engines	CO_2 Vent	Storage Tanks	Urea Granulation Line
Nitrogen Gas Blanket								2	
Oxidation Catalyst	1								
Proper Catalyst Selection							5		
Wet Scrubber								2	3
Tank Design								2	
Federal Emission Standards						9			
Limited Operation			1	1		1			
Flare Work Practice Requirements					4				
Flare Minimization Plan					9				
No Control Specified		2	5	5	4	8	2	1	1
Total	**7**	**14**	**25**	**25**	**17**	**31**	**10**	**7**	**4**

5.1 VOC BACT for the Cogeneration Turbines (EUs 55a – 59a) with Waste Heat Boilers (EUs 50 – 54)

Possible VOC emission control technologies for the cogeneration turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 16.210: small combined cycle and cogeneration natural gas-fired combustion turbines (≤25 MW). The search results are summarized below:

VOC Controls for Small Combined Cycle and Cogeneration Gas-Fired Turbines		
Control Technology	**Number of Determinations**	**Emission Limits**
Oxidation Catalyst	1	1.6 ppmv @ 15% O_2
Good Combustion Practices & Clean Fuel	6	2.5 – 25 ppmv @ 15% O_2 5.5 lb/MMSCF (0.0054 lb/MMBtu)

Step 1- Identify VOC Control Technologies for the Cogeneration Turbines

From research, the Department identified the following technologies as available for VOC control of gas-fired combined cycle and cogeneration combustion 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%. There was one stationary source in the RBLC with an oxidation catalyst used for controlling VOC emissions. Therefore, the use of an oxidation catalyst is considered a technically feasible control technology for the cogeneration turbines.

(b) Good Combustion Practices (GCP) and Clean Fuel
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, GCPs and clean fuel are a feasible control method for the cogeneration turbines.

Step 2 - Eliminate Technically Infeasible VOC Control Options for Cogeneration Turbines
As explained in Step 1, catalytic oxidation and good combustion practices are technically feasible options to control VOC emissions from turbines smaller than 25 MW.

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

(a) Oxidation Catalyst (70 – 90% Control)
(b) GCPs & Clean Fuel (less than 40% Control)

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

RBLC Review
A review of similar units in the RBLC indicates that an oxidation catalyst and good combustion practices are the principle VOC control technologies used for combined cycle and cogeneration gas-fired turbines rated at 25 MW or less.

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.3	1.3	$1,924,900	$1,383,900	$1,074,457
Capital Recovery Factor = 0.1424 (7% for a 10 year life cycle)					

The applicant contends that the economic analysis indicates the level of VOC reduction from an oxidation catalyst does not justify the use of an oxidation catalyst for the cogeneration turbines based on the excessive cost per ton of VOC removed per year.

Agrium proses that BACT for the cogeneration turbines is GCPs and clean fuel and that VOC emissions shall not exceed 0.0054 lb/MMBtu from the turbines and 0.0021 lb/MMBtu from the waste heat boilers (0.0036 lb/MMBtu weighted average).

Department Evaluation of BACT for VOC Emissions from Cogeneration Turbines
The Department revised the cost analysis provided by Agrium to include CO and VOC emissions removed into one cost calculation, reflect the equipment life revised to a 25 year lifespan, adjusted the interest rate to the current bank prime interest rate of 3.25%, reduced the CO and VOC control efficiencies of the oxidation catalyst from 99% to 90% and 80% to 70% respectively. A summary of the analysis for the cogeneration gas turbines is shown below:

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	5.4	45.0	$1,924,900	$1,223,300	$27,167
Capital Recovery Factor = 0.0590 (3.25% for a 25 year life cycle)					

The Department's economic analysis indicates the level of CO and VOC reduction does not justify the use of an oxidation catalyst as BACT for the small cogeneration gas-fired combustion turbines based on the excessive cost per ton of CO and VOC emissions removed.

Step 5 – Selection of VOC BACT for Cogeneration Turbines
The Department's finding is that BACT for VOC emissions from the cogeneration gas-fired combustion turbines rated at 25 MW or less is as follows:

(a) VOC emissions from EUs 55a – 59a and their associated waste heat boilers EUs 50 – 54 shall be minimized by burning clean fuel and by maintaining good combustion practices by following the manufacturer's operating and maintenance procedures at all times the units are in operation;

(b) VOC emissions from EUs 55a – 59a and their associated waste heat boilers EUs 50 – 54 shall not exceed 0.0036 lb/MMBtu averaged over a 3-hour period; and

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

5.2 VOC BACT for the Primary Reformer (EU 12)

Possible VOC emission control technologies for the primary reformer were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years with the process name containing the word *reformer*. The search results were then filtered to include all relevant reformers with natural gas as the primary fuel input. The search results are summarized below:

VOC Controls for Reformer Furnaces		
Control Technology	**Number of Determinations**	**Emission Limits (lb/MMBtu)**
GCPs and Clean Fuel	12	0.0014 – 0.0054
No Control Specified	2	0.0015 – 0.0054

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

(a) Oxidation Catalyst
The theory of oxidation catalysts were discussed in detail in the CO BACT section for the turbines and will not be repeated here. The Department's search of the RLBC database did not identify any oxidation catalysts used as a VOC control device for reformer furnaces. Additionally, an oxidation catalyst was previously shown to be cost ineffective in the CO BACT section for the primary reformer. Therefore, the Department does not consider oxidation catalysts to be a technically or economically feasible control technology for the primary reformer.

(b) Good Combustion Practices (GCP) and Clean Fuel
The theory of GCPs and clean fuel was discussed in detail in the NOx BACT section for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of VOC. The majority of facilities in the RBLC are using good combustion practices to control VOC emissions from reformer furnaces. Therefore, the use of GCPs and clean fuel is considered a technically feasible control option for the primary reformer.

Step 2 – Eliminate Technically Infeasible VOC Control Options for the Primary Reformer
As explained in Step 1, an oxidation catalyst is not a feasible control technology to reduce VOC emissions from the reformer furnace.

Step 3 – Rank Remaining VOC Control Technologies for the Primary Reformer
The applicant has proposed the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
GCPs and clean fuel is the most effective VOC control for reformer furnaces. Since GCPs and clean fuel is not an add-on control, there is no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates GCPs and clean fuel are the principle VOC control technologies for reformer furnaces.

Applicant Proposal
Agrium proposes that BACT for the primary reformer is GCPs and clean fuel, and that VOC emissions shall not exceed 0.0054 lb/MMBtu

Step 5 – Selection of VOC BACT for the Primary Reformer

The Department's finding is that BACT for VOC emissions from the primary reformer is as follows:

(a) VOC emissions from EU 12 shall be minimized by burning clean fuel and by maintaining good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation;

(b) VOC emissions from EU 12 shall not exceed 0.0054 lb/MMBtu averaged over a 3-hour period (AP-42 Table 1-4.2, converted to lb/MMBtu); and

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

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

Possible VOC emission control technologies for the package boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.310: Industrial Sized Natural Gas-Fired Boilers/Furnaces (>100 MMBtu/hr and <250 MMBtu/hr). The search results are summarized below:

VOC Controls for Industrial Sized Gas-Fired Boilers/Furnaces		
Control Technology	**Number of Determinations**	**Emission Limits (lb/MMBtu)**
GCPs and Clean Fuel	19	0.0005 – 0.006
Limited Use	1	0.0054
No Control Specified	5	0.005 – 0.0054

Step 1 – Identify VOC Control Technologies for the Package Boilers

From research, the Department identified the following technologies as available for VOC control for the package boilers:

(a) Oxidation Catalyst
The theory of oxidation catalysts was discussed in detail in the CO BACT section for the turbines and will not be repeated here. The Department's search of the RLBC database did not identify any oxidation catalysts used as a VOC control device for gas-fired boilers rated at less than 250 MMBtu/hr. Therefore, the Department does not consider oxidation catalysts to be a technically feasible control technology for the package boilers.

(b) Good Combustion Practices (GCP) and Clean Fuels
The theory of good combustion practices was discussed in detail in the NOx BACT section for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of CO. GCPs and clean fuel is considered a feasible control option for the package boilers.

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

As explained in Step 1, an oxidation catalyst is not feasible to control CO from the package boilers. Additionally, the package boilers are used to generate steam for plant operations and therefore are not able to use limited operation as a possible control option.

Step 3 – Rank Remaining VOC Control Technologies for the Package Boilers
The applicant has proposed the only feasible control technology for the package boilers. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
According to the RBLC, good combustion practices and clean fuel are the applicable controls for VOC emissions for the package boilers. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates good combustion practices and burning clean fuel, as well as limited operation are the principle VOC control technologies installed on gas-fired boilers/furnaces rated between 100 and 250 MMBtu/hr.

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	1.1	4.6	$2,277,900	$1,747,300	$383,584
Capital Recovery Factor = 0.1424 (7% for a 10 year life cycle)					

The applicant contends that the economic analysis indicates the level of VOC reduction from an oxidation catalyst does not justify the use of an oxidation catalyst for the package boilers based on the excessive cost per ton of VOC removed per year.

The applicant proposes the following as BACT for VOC emissions from the package boilers:

(a) VOC emissions from the package boilers shall not exceed 5.5 lb/MMscf (0.0054 lb/MMBtu); and

(d) VOC emissions from the package boilers shall be controlled by maintaining good combustion practices.

Department Evaluation of BACT for VOC Emissions from Package Boilers
The Department revised the cost analysis provided by Agrium to include CO and VOC emissions removed into one cost calculation, reflect the equipment life revised to a 25 year lifespan, adjusted the interest rate to the current bank prime interest rate of 3.25%, reduced the CO and VOC control efficiencies of the oxidation catalyst from 99% to 90% and 80% to 70% respectively. A summary of the analysis for the package boilers is shown below:

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	5.6	39.4	$2,277,900	$1,557,200	$39,498
Capital Recovery Factor = 0.0590 (3.25% for a 25 year life cycle)					

The Department's economic analysis indicates the level of CO and VOC reduction does not justify the use of an oxidation catalyst as BACT for the package boilers based on the excessive cost per ton of CO and VOC emissions removed.

Step 5 – Selection of VOC BACT for the Package Boilers
The Department's finding is that BACT for VOC emissions from the package boilers rated between 100 and 250 MMBtu/hr is as follows:

(a) VOC emissions from EUs 44a, 48a, and 49a shall be controlled by maintaining good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation;

(b) VOC emissions from EUs 44a, 48a, and 49a shall not exceed 0.0054 lb/MMBtu averaged over a 3-hour period (AP-42 Table 1-4.2, converted to lb/MMBtu); and

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

5.4 VOC BACT for the Startup Heater (EU 13)

Possible VOC emission control technologies for the package boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.310: Industrial Sized Natural Gas-Fired Boilers/Furnaces (>100 MMBtu/hr and <250 MMBtu/hr). The search results are summarized below:

VOC Controls for Industrial Sized Gas-Fired Boilers/Furnaces		
Control Technology	**Number of Determinations**	**Emission Limits (lb/MMBtu)**
GCPs and Clean Fuel	19	0.0005 – 0.006
Limited Use	1	0.0054
No Control Specified	5	0.005 – 0.0054

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

(a) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. The startup heater is considered a limited use EU and has an existing limit of 200 hours per 12 consecutive month period. Therefore, the Department considers limited operation a technically feasible control technology for the startup heater.

(b) Oxidation Catalyst
The theory of oxidation catalysts was discussed in detail in the CO BACT section for the turbines and will not be repeated here. The Department's search of the RLBC database did not identify any oxidation catalysts used as a VOC control device for gas-fired boilers rated at less than 250 MMBtu/hr. Therefore, the Department does not consider oxidation catalysts to be a technically feasible control technology for the startup heater.

(c) Good Combustion Practices (GCP) and Clean Fuels
The theory of good combustion practices was discussed in detail in the NOx BACT section for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of VOC. GCPs and clean fuel is considered a feasible control option for the startup heater.

Step 2 – Eliminate Technically Infeasible VOC Control Options for the Startup Heater
As explained in Step 1, an oxidation catalyst is not a feasible control technology to reduce VOC emissions from the startup heater.

Step 3 – Rank Remaining VOC Control Technologies for the Startup Heater
The applicant has proposed the only feasible control option for the startup heater. Therefore, ranking is not required

Step 4 – Evaluate the Most Effective Controls
According to the RBLC, good combustion practices and clean fuel are the applicable controls for VOC emissions for the startup heater. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates good combustion practices and burning clean fuel, as well as limited operation are the principle VOC control technologies installed on gas-fired boilers/furnaces rated between 100 and 250 MMBtu/hr.

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 5.5 lb/MMscf (0.0054 lb/MMBtu); and

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

Step 5 – Selection of VOC BACT for the Startup Heater
The Department's finding is that BACT for VOC emissions from the startup heater is as follows:

(a) VOC emissions from EU 13 shall be controlled by limiting operations of the EU to no more than 200 hours per 12 consecutive month period;

(b) VOC emissions from EU 13 shall be controlled by maintaining good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation;

(c) VOC emissions from EU 13 shall not exceed 0.0054 lb/MMBtu averaged over a 3-hour period (AP-42 Table 1-4.2, converted to lb/MMBtu); and

(d) Compliance with the proposed limit will be demonstrated by monitoring, recording, and reporting the operating hours of EU 13.

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

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

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

Step 1 – Identify VOC Control Technologies for the Flares

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

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

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

(c) Flare Gas Recovery
Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams, such as petroleum refineries, to reduce gaseous emissions to the atmosphere by recovering waste gas to be reused in the production process. However, flare gas recovery 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 Step 1, flare gas recovery is not feasible to control VOC emissions from the flares.

Step 3 – Rank Remaining VOC Control Technologies for the Flares
Agrium has proposed the remaining two technically feasible control options for the flares EUs 11, 22, and 23. Therefore, ranking is not required.

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

Applicant Proposal
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) VOC emissions from the ammonia tank flare, small flare, and emergency flare shall not exceed 0.14 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’s finding is that BACT for CO emissions from the flares is as follows:

(a) Venting to the ammonia tank flare EU 11, small flare EU 22, 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 0.66 lb/MMBtu (AP-42 Table 13.5-2, 02/18, VOC for elevated flares) during normal operation, based on a three-hour average.

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

Possible VOC emission control technologies for limited use internal combustion engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17:210: Small Fuel Oil-Fired Internal Combustion Engines (<500 hp) and 17:220: Small Other Liquid Fuel & Liquid Fuel Mixtures-Fired Internal Combustion Engines (<500 hp). The search results are summarized below:

VOC Controls for Small Diesel-Fired Engines		
Control Technology	**Number of Determinations**	**Emission Limits (g/hp-hr)**
Federal Emission Standards	9	0.15 – 0.37
Good Combustion Practices	13	0.05 - 1.6
No Control Specified	8	0.15 - 1.14

VOC Controls for Small Gasoline-Fired Engines		
Control Technology	**Number of Determinations**	**Emission Limits (lb/MMBtu)**
Limited Operation	1	3.03

Step 1 – Identify VOC Control Technologies for the Pump Engines

From research, the Department identified the following technologies as available for VOC control of the pump engines:

(a) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. The pump engines are considered limited use EUs and both have existing permit limits of 168 hours per 12 consecutive month period. Therefore, the Department considers limited operation a technically feasible control technology for the pump engines.

(b) Oxidation Catalyst
The theory of oxidation catalysts was discussed in detail in the CO BACT section for the turbines and will not be repeated here. The Department's search of the RLBC database did not identify any oxidation catalysts used as a VOC control device for small diesel or gasoline-fired engines. Therefore, the Department does not consider oxidation catalysts to be a technically feasible control technology for the pump engines.

(c) Good Combustion Practices (GCP) and clean fuel
The theory of GCPs and clean fuel was discussed in detail in NOx BACT section for the turbines and will not be repeated here. The Department's search of the RLBC database indicated that GCPs and clean fuel are commonly used to control VOC emissions for small diesel and gasoline-fired engines. Therefore, the Department considers GCPs and clean fuel to be a technically feasible control technology for the pump engines.

(d) Federal Emission Standards
Federal emission standards require the engines meet the requirements of 40 C.F.R. 60 Subparts IIII and JJJJ, and 40 C.F.R 63 Subpart ZZZZ, or EPA tier certifications. Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. Subpart JJJJ applies to spark ignition internal combustion engines manufactured after various dates in the 2000s. EUs 65 and 66 are both manufactured prior to NSPS Subparts IIII and JJJJ, and NESHAP Subpart ZZZZ does not contain VOC emission limits for emergency engines at area sources of hazardous air pollutants (HAPs). Therefore the federal emission standards for VOC are not applicable to the pump engines.

Step 2 – Eliminate Technically Infeasible VOC Control Options for the Pump Engines
As explained in Step 1, The Department does not consider oxidation catalysts and federal emission standards as technically feasible to control VOC emissions from the pump engines.

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

Step 4 – Evaluate the Most Effective Controls
Limited operation is the most effective VOC control for small internal combustion engines. Since limited operation is not an add-on control, there is no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates good combustion practices, limited operation, and federal emission standards are the principle VOC control technologies for both diesel-fired and gasoline-fired pump engines.

Applicant Proposal
The applicant proposes the following as BACT for VOC emissions from the pump engines:

(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 EU 65 shall not exceed 0.36 lb/MMBtu;

(c) VOC emissions from the gasoline-fired fire water pump EU 66 shall not exceed 3.03 lb/MMBtu; and

(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's finding is that BACT for VOC emissions from the well pump and fire pump engines is as follows:

(a) Limit operation of EUs 65 and 66 to no more than 168 hours each, in any 12 consecutive month period;

(b) VOC emissions from the diesel-fired well pump engine EU 65 will not exceed 0.36 lb/MMBtu (AP-42 Table 3.3-1, TOC emissions for uncontrolled diesel engines);

(c) VOC emissions from the gasoline-fired fire pump engine EU 66 will not exceed 3.03 lb/MMBtu (AP-42 Table 3.3-1, TOC emissions for uncontrolled gasoline engines); and

(d) Compliance with the proposed limits will be demonstrated by recording and reporting operating hours for the pump engines.

5.7 VOC BACT for the CO_2 Vent (EU 14)

Possible VOC emission control technologies for the CO_2 vent were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 61.012: fertilizer production and 62.999: other inorganic chemical manufacturing. The search results were then filtered to include all relevant CO_2 vents. The search results are summarized below:

VOC Controls for CO_2 Vent		
Control Technology	**Number of Determinations**	**Emission Limits (lb/hr)**
Thermal Oxidation & Proper Catalyst Selection	5	5.58 – 8.30
Good Operating Practices	3	14.57 – 33.64
No Control Specified	2	11.4 – 13.1

Step 1 – Identify VOC Control Technologies for the CO_2 Vent

The Department has identified the following control technologies for the CO_2 purification process.

(a) Proper Selection of Process Catalyst & Good Operating Practices
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 and good operating practices is a feasible control option for the CO_2 vent.

Step 2 – Eliminate Technically Infeasible VOC 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 – Rank Remaining VOC Control Technologies for the CO_2 Vent
The applicant has proposed the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
Proper selection of a catalyst and good operational practices will reduce VOC emissions from the CO_2 vent while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary.

RBLC Review
A review of similar units in the RBLC indicates that proper catalyst selection for the conversion of CO to CO_2 and good operating practices are the principle CO control technologies used for CO_2 vents at similar sources.

Applicant Proposal
Agrium proposes to limit VOC emissions from the CO_2 Vent EU 14 by use of good operational practices including the selection of an optimal process catalyst, with VOC emissions limited to 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's finding is that BACT for VOC emissions from the CO_2 vent is as follows:

(a) VOC emissions from the CO_2 vent EU 14 shall be controlled by operating and maintaining a catalyst at all times the EU is in operation; and

(b) VOC emissions from the CO_2 vent EU 14 shall not exceed 11.4 lb/hr averaged over a 3-hour period at 100% venting.

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

Possible VOC emission control technologies for the urea granulation process were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years with the process name containing the words *urea granulation* or *urea granulator*. The search results are summarized below:

VOC Controls for Urea Granulation Vents		
Control Technology	**Number of Determinations**	**Emission Limits**
Wet Scrubber	3	0.05 – 0.3 lb/ton of urea produced 90% control or 2 ppmv (whichever is less)
No Control Specified	1	0.017 lb/ton of urea produced

Step 1 – Identify VOC Control Technologies for Urea Granulation
From research, the Department identified the following technologies as available for VOC control of the urea granulation process:

(a) Thermal Oxidizers
The theory of thermal oxidizers was discussed in detail in the VOC BACT section 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, and the fact that there were no instances of a thermal oxidizer used to control urea granulation in the RBLC, this control option is eliminated from further consideration.

(b) Catalytic Oxidizers
Catalytic oxidizers rely 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, and the fact that there were no instances of a thermal oxidizer used to control urea granulation in the RBLC, this control option is eliminated from further consideration.

(c) Wet Scrubbers
Wet scrubbing is an effective means of removing soluble or condensable organic vapors in 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. 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 process.

Step 2 - Elimination of Technically Infeasible VOC Controls for Urea Granulation
As explained in Step 1, 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 proposed the only feasible control option. Therefore, ranking is not required.

Step 4 - Evaluate the Most Effective Controls
Installation of a wet scrubber will reduce VOC emissions from the urea granulation process while having minimal energy and environmental impacts. This system requires water for scrubbing and produces a waste effluent that can be treated for reuse.

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

Applicant Proposal
The applicant proposes the following as BACT for VOC emissions from the urea granulation process:

(a) VOC emissions from the operation of the urea granulators EUs 35 and 36 shall be controlled with the use of wet scrubbers; and

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

Step 5 – Selection of VOC BACT for Urea Granulation
The Department's finding is that BACT for VOC emissions from the urea granulation process EUs 35 and 36 is as follows:

(a) VOC emissions from the operation of the urea granulators shall be controlled with the use of wet scrubbers;

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

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

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

Possible VOC emission control technologies for the urea formaldehyde (UF-85) storage tank were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years with the process name containing the word *storage tank*, and filtered to include the appropriate entries. The search results are summarized below:

VOC Controls for UF-85 Storage Tank		
Control Technology	**Number of Determinations**	**Emission Limits (lb/hr)**
Wet Scrubber	2	0.00004 – 0.046

Step 1 – Identify VOC Control Technologies 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 section for the urea granulation process 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 stationary source due to the low potential VOC emissions of less than 1 tpy from the tank.

Step 2 - Elimination of Technically Infeasible VOC Controls for UF-85 Storage Tank

As explained in Step 1, tank design (floating roof) is a technically infeasible control option for controlling VOC emissions.

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

Step 4 - Evaluate the Most Effective Controls
Installation of a wet scrubber will reduce VOC emissions from the UF-85 storage tank while having minimal energy and environmental impacts. This system requires water for scrubbing and produces a waste effluent that can be treated for reuse.

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

Applicant Proposal
Agrium proposes to control VOC emissions from the UF-85 storage tank EU 41A by using a wet scrubber when filling the tank, with VOC emissions limited to 0.00004 lb/hr.

Step 5 – Selection of VOC BACT for the UF-85 Storage Tank
The Department's finding is that BACT for VOC emissions from the UF-85 storage tank is as follows:

(a) VOC emissions from the UF-85 storage tank EU 41A shall be controlled by operating and maintaining a wet scrubber at all times the tank is being filled; and

(c) VOC emissions from the UF-85 storage tank EU 41A shall not exceed 0.00004 lb/hr averaged over a 3-hour period.

5.10 VOC BACT for the Methyl Diethanolamine (MDEA) Storage Tanks (EUs 41B and 41C)

Possible VOC emission control technologies for the Methyl Diethanolamine (MDEA) storage tanks were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years with the process name containing the word *storage tank*, and filtered to include the appropriate entries. The search results are summarized below:

VOC Controls for MDEA Storage Tanks		
Control Technology	**Number of Determinations**	**Emission Limits (tpy)**
Tank Blanketing	2	0.1
Tank Design (submerged fill)	2	0.002
No Control Specified	1	None Specified

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

(a) Wet Scrubber

The theory of wet scrubbers was discussed in detail in the VOC BACT section for the urea granulation process and will not be repeated here. There are no examples of wet scrubbers used on MDEA storage tanks in the RBLC. Therefore, this control technology is considered economically infeasible.

(b) Tank Design
The theory of tank design was discussed in detail in the VOC BACT section 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.

(c) Tank Blanketing
Tank blanketing (also referred to as tank padding) is the process of applying a gas to the empty space in a storage tank to minimize losses of VOC. There are two examples of MDEA storage tanks in the RBLC tank blanketing with nitrogen gas to control VOC emissions. However, tank blanketing is not a practical control option as the two MDEA storage tanks have a combined PTE of well under 1 tpy of VOC emissions.

Step 2 - Elimination of Technically Infeasible VOC Controls for MDEA Storage Tank
As explained in Step 1, wet scrubber and tank blanketing are technically infeasible options for controlling VOC emissions.

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

Step 4 - Evaluate the Most Effective Controls
MDEA storage tanks using submerged fill have the lowest VOC emissions in the RBLC database. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates submerged fill and tank blanketing are the principle VOC control devices installed on MDEA storage tanks.

Applicant Proposal
Agrium proposes to limit VOC emissions from the MDEA storage tanks EUs 41B and 41C by using submerged fill when filling the tank, with VOC emissions limited to 0.002 tpy combined.

Step 5 – Selection of VOC BACT for the MDEA Storage Tanks
The Department’s finding is that BACT for VOC emissions from the MDEA storage tanks is as follows:

(a) VOC emissions from the MDEA storage tanks EUs 41B and 41C shall be controlled by operating and maintaining tanks with submerged fill design; and

(b) VOC emissions from the MDEA storage tanks EUs 41B and 41C shall not exceed 0.002 tpy combined.

6.0 BACT DETERMINATION FOR PM, PM-10, and PM-2.5 (PARTICULATES)

The KNO facility plans to install three gas-fired package boilers rated at 243 MMBtu/hr each, and five gas-fired Solar GSC-4701 turbine generator sets rated at 55.4 MMBtu/hr each that will be operated in combination with five existing gas-fired waste heat boilers to make five turbine cogeneration systems. Additionally, the KNO facility has previously installed one 1,350 MMBtu/hr primary reformer, flares, and several other EUs subject to BACT. The Department reviewed the control technologies Agrium identified in their application and determined particulate BACT for the EUs listed in Table B-5.

The Department based its assessment on BACT determinations found in the RBLC and internet research. Table B-5 summarizes particulate BACT determinations in the RBLC in the last 10 years for the proposed EU types.

Table B-5: Particulate BACT Determinations in RBLC

Description of PM BACT	Cogeneration Gas Turbines	Primary Reformer	Startup Heater	Package Boilers	Flares	Cooling Towers	Pump Engines	Urea Granulators, Transfer, and Loading
Good Combustion Practices & Clean Fuel	13	32	33	33			89	
Good Operating Practices								
Equipment Design								
Wet Scrubbers								24
Diesel Particulate Filter							2	
Drift Eliminators						68		
Bin Vent Filter								3
Coolers, Partial Enclosure & Telescoping Chute								3
Flare Work Practice Requirements					10			
Flaring Minimization Plan					25			
Limited Operation			2	2			3	
No Control Specified	6	5	7	7	9	3	32	3
Total	**19**	**37**	**42**	**42**	**44**	**71**	**126**	**33**

6.1 Particulate BACT for the Cogeneration Turbines (EUs 55a – 59a) with Waste Heat Boilers (EUs 50 – 54)

Possible particulate emission control technologies for the cogeneration turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 16.210: small combined cycle and cogeneration natural gas-fired combustion turbines (≤25 MW). The search results are summarized below:

Particulate Controls for Small Combined Cycle and Cogeneration Gas-Fired Turbines		
Control Technology	**Number of Determinations**	**Emission Limits (lb/MMBtu)**
Good Combustion Practices & Clean Fuel	13	0.0019 – 0.019
No Control Specified	6	0.0089 – 0.02

Step 1- Identify Particulate Control Technologies for the Cogeneration Turbines
From research, the Department identified the following technologies as available for particulate control of gas-fired combined cycle and cogeneration combustion turbines rated at 25 MW or less:

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

(b) Good Combustion Practices
As discussed in detail in the NOx BACT section, proper management of the combustion process will result in a reduction of particulates. Therefore good combustion practices is a feasible control option for the small cogeneration gas-fired turbines.

Step 2 - Eliminate Technically Infeasible Particulate Control Options for Cogeneration Turbines
All control technologies identified are technically feasible for cogeneration gas-fired turbines rated at 25 MW or less.

Step 3 - Rank Remaining Particulate Control Technologies for Cogeneration Turbines
The applicant has proposed the only feasible control option. Therefore, ranking is not required.

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

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

Applicant Proposal
Agrium proposes to use clean fuel and good combustion practices for the cogeneration turbines as BACT for reducing particulate emissions. Particulate emissions from the cogeneration turbines will not exceed 7.6 lb/MMscf (0.0075 lb/MMBtu).

Step 5 – Selection of Particulate BACT for the Cogeneration Turbines

The Department's finding is that BACT for particulate emissions from the cogeneration gas-fired combustion turbines rated at 25 MW or less is as follows:

(a) Particulate emissions from EUs 55a – 59a and their associated waste heat boilers EUs 50 – 54 shall be minimized by maintaining good combustion practices and burning clean fuels at all times the units are in operation;

(b) Particulate emissions from EUs 55a – 59a and their associated waste heat boilers EUs 50 – 54 shall not exceed 0.0075 lb/MMBtu averaged over a 3-hour period (AP-42 Table 1.4-2, PM (Total) for natural gas combustion converted to lb/MMBtu); and

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

6.2 Particulate BACT for the Primary Reformer (EU 12)

Possible particulate emission control technologies for the primary reformer were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years with the process name containing the word *reformer*. The search results were then filtered to include all relevant reformers with natural gas as the primary fuel input. The search results are summarized below:

Particulate Controls for Reformer Furnaces		
Control Technology	**Number of Determinations**	**Emission Limits (lb/MMBtu)**
GCP & Clean Fuels	32	0.0019 - 0.0076
Wet Scrubber	0	N/A
No Control Specified	5	0.0074 - 0.0075

Step 1 – Identify Particulate Control Technologies for the Primary Reformer

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

(a) Baghouse

Baghouses are comprised of an array of filter bags contained in housing. Air passes through the filter media from the "dirty" to the "clean" side of the bag. These devices undergo periodic bag cleaning based on the build-up of filtered material on the bag as measured by pressure drop across the device. The cleaning cycle is set to allow operation within a range of design pressure drop. Baghouses are characterized by the type of cleaning cycle - mechanical-shaker, pulse-jet, and reverse-air. Fabric filter systems have control efficiencies of 95% to 99.9% [4] and are generally specified to meet a discharge concentration of filterable particulate (e.g., 0.01 grains per dry standard cubic feet). There were no reformer furnaces using baghouses in the RBL. Therefore, the Department does not consider a baghouse a technically feasible control technology for the primary reformer.

[4] https://www3.epa.gov/ttn/catc/dir1/ff-shaker.pdf
https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf
https://www3.epa.gov/ttn/catc/dir1/ff-revar.pdf

(b) Wet Scrubber
Wet Scrubbers use a scrubbing solution to remove particulate matter from exhaust 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 flows in the opposite direction as the gas flow. The only entry for wet scrubbers in the RBLC was for a furnace at an iron ore concentrate pelletizing facility in Texas. This process involves iron ore pellets being exposed to high temperatures in a furnace in order to harden the pellets, which emits HAPs. Due to the fact that the only reformer in the RBLC with a wet scrubber used to control particulates was actually installed because of the iron ore pelletizing process, the Department does not consider the use of wet scrubbers a technically feasible control technology for the primary reformer located at the KNO facility.

(c) Good Combustion Practices (GCP) and Clean Fuels
The theory of GCP and clean fuels was discussed in detail in the NOx BACT section for the turbines and will not be repeated here. Proper management of the combustion process and burning clean fuels will result in a reduction of particulate emissions. The majority of reformer furnaces in the RBLC are using GCPs and clean fuel to control particulate emissions. Therefore, the use of GCPs and clean fuels is considered a technically feasible control technology for the primary reformer.

Step 2 – Eliminate Technically Infeasible Particulate Control Options for the Primary Reformer
As explained in Step 1, baghouses and wet scrubbers are not feasible to control particulate emissions from the primary reformer.

Step 3 - Rank Remaining Particulate Control Technologies for the Primary Reformer
The applicant has proposed the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
Use of clean low-sulfur fuel and good combustion practices are the most effective controls for particulates from reformer furnaces. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that use of clean fuels and good combustion practices are the principle control methods for particulates from reformer furnaces.

Applicant Proposal
Agrium proposes that BACT for the primary reformer is GCPs and clean fuel, and that particulate emissions shall not exceed 7.6 lb/MMscf (0.0075 lb/MMBtu)

Step 5 – Selection of Particulate BACT for the Primary Reformer
The Department's finding is that BACT for particulate emissions from the primary reformer is as follows:

(a) Particulate emissions from EU 12 shall be minimized by burning clean fuel and by maintaining good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation;

(b) Particulate emissions from EU 12 shall not exceed 0.0075 lb/MMBtu averaged over a 3-hour period (AP-42 Table 1-4.2, PM (Total) for natural gas combustion converted to lb/MMBtu); and

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

6.3 Particulate BACT for the Package Boilers (EUs 44a, 48a, and 49a)

Possible particulate emission control technologies for the package boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.310: Industrial Sized Natural Gas-Fired Boilers/Furnaces (>100 MMBtu/hr and <250 MMBtu/hr). The search results are summarized below:

Particulate Controls for Industrial Sized Gas-Fired Boilers/Furnaces		
Control Technology	**Number of Determinations**	**Emission Limits (lb/MMBtu)**
GCPs and Clean Fuel	33	0.00052 – 0.0075
Limited Use	2	0.0074
No Control Specified	7	0.0074 – 0.0075

Step 1 – Identification of Particulate Control Technologies for the Package Boilers

From research, the Department identified the following technologies as available for particulate control for the package boilers:

(a) Baghouse
The theory behind baghouses was discussed in detail in the particulate BACT section for the primary reformer and will not be repeated here. The Department did not identify any industrial sized gas-fired boilers in the RBLC using baghouses to control particulate emissions. Therefore, the Department does not consider baghouses as a feasible control technology for the package boilers.

(b) Wet Scrubbers
The theory behind wet scrubbers was discussed in detail in the particulate matter BACT section for the primary reformer and will not be repeated here. The Department did not identify any industrial sized gas-fired boilers in the RBLC using wet scrubbers to control particulate emissions. Therefore, the Department does not consider wet scrubbers as a feasible control technology for the package boilers.

(c) Good Combustion Practices (GCP) and Clean Fuels
The theory of good combustion practices was discussed in detail in the NOx BACT section for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of particulate emissions. GCPs and clean fuel is considered a feasible control option for the package boilers.

Step 2 – Eliminate Technically Infeasible Particulate Control Options for the Package Boilers
As explained in Step 1, baghouses and wet scrubbers are not feasible to control particulate emissions from the package boilers. Additionally, the package boilers are used to generate steam for plant operations and therefore are not able to use limited operation as a possible control option.

Step 3 – Rank Remaining Particulate Control Technologies for the Package Boilers
The applicant has proposed the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
According to the RBLC, good combustion practices and clean fuel are the applicable controls for particulate emissions for the package boilers. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates good combustion practices and burning clean fuel, as well as limited operation are the principle particulate control technologies installed on gas-fired boilers/furnaces rated between 100 and 250 MMBtu/hr.

Applicant Proposal
Agrium proposes that BACT for the package boilers is GCPs and clean fuel, and that particulate emissions shall not exceed 7.6 lb/MMscf (0.0075 lb/MMBtu).

Step 5 – Selection of Particulate BACT for the Package Boilers
The Department's finding is that BACT for particulate emissions from the package boilers is as follows:

(a) Particulate emissions from EUs 44a, 48a, and 49a shall be minimized by burning clean fuel and by maintaining good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation;

(b) Particulate emissions from EUs 44a, 48a, and 49a shall not exceed 0.0075 lb/MMBtu averaged over a 3-hour period (AP-42 Table 1-4.2, PM (Total) for natural gas combustion converted to lb/MMBtu); and

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

6.4 Particulate BACT for the Startup Heater (EU 13)
Possible particulate emission control technologies for the startup heater were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.310: Industrial Sized Natural Gas-Fired Boilers/Furnaces (>100 MMBtu/hr and <250 MMBtu/hr). The search results are summarized below:

Particulate Controls for Industrial Sized Gas-Fired Boilers/Furnaces		
Control Technology	**Number of Determinations**	**Emission Limits (lb/MMBtu)**
GCPs and Clean Fuel	33	0.00052 – 0.0075
Limited Use	2	0.0074
No Control Specified	7	0.0074 – 0.0075

Step 1 – Identify Particulate Control Technologies for the Startup Heater
From research, the Department identified the following technologies as available for particulate control of startup heaters:

(a) Baghouse
The theory behind fabric filters was discussed in detail in the particulate BACT section for the primary reformer and will not be repeated here. The Department did not identify any industrial sized gas-fired boilers in the RBLC using baghouses to control particulate emissions. Therefore, the Department does not consider baghouses as a feasible control technology for the startup heater.

(b) Wet Scrubbers
The theory behind wet scrubbers was discussed in detail in the particulate matter BACT section for the primary reformer and will not be repeated here. The Department did not identify any industrial sized gas-fired boilers in the RBLC using wet scrubbers to control particulate emissions. Therefore, the Department does not consider wet scrubbers as a feasible control technology for the startup heater.

(c) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. The startup heater is considered a limited use EU and has an existing limit of 200 hours per 12 consecutive month period. Therefore, the Department considers limited operation a technically feasible control technology for the startup heater.

(d) Good Combustion Practices (GCP) and Clean Fuels
The theory of good combustion practices was discussed in detail in the NOx BACT section for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of particulate emissions. GCPs and clean fuel is considered a feasible control option for the startup heater.

Step 2 – Eliminate Technically Infeasible Particulate Control Options for the Startup Heater
As explained in Step 1, baghouses and wet scrubbers are not feasible to control particulate emissions from the startup heater.

Step 3 – Rank Remaining Particulate Control Technologies for the Startup Heater
The applicant has proposed the only feasible control options. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
According to the RBLC, good combustion practices and clean fuel, as well as limited operation are the applicable controls for particulate emissions for the startup heater. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates good combustion practices and burning clean fuel, as well as limited operation are the principle particulate control technologies installed on gas-fired boilers/furnaces rated between 100 and 250 MMBtu/hr.

Applicant Proposal
The applicant proposes the following as BACT:

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

(c) Particulate emissions from the startup heater shall not 7.6 lb/MMscf (0.0075 lb/MMBtu); and

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

Step 5 – Selection of Particulate BACT for the Startup Heater
The Department's finding is that BACT for particulate emissions from the startup heater is as follows:

(a) Particulate emissions from EU 13 shall be controlled by limiting operations of the EU to no more than 200 hours per 12 consecutive month period;

(b) Particulate emissions from EU 13 shall be controlled by maintaining good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation;

(d) Particulate emissions from EU 13 shall not exceed 0.0075 lb/MMBtu averaged over a 3-hour period (AP-42 Table 1-4.2, PM (Total) for natural gas combustion converted to lb/MMBtu); and

(e) Compliance with the proposed limit will be demonstrated by monitoring, recording, and reporting the operating hours of EU 13.

6.5 Particulate BACT for the Ammonia Tank Flare and Small Flares (EUs 11, 22, and 23)
Possible particulate emission control technologies for the flares were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 19: Miscellaneous combustion (19:300 is specific to flares) and 50: Petroleum/Natural Gas Production and Refining. The search results were then filtered to include only emissions units with flares. The search results are summarized below:

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

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

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

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

(c) Flare Gas Recovery
Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams, such as petroleum refineries, to reduce gaseous emissions to the atmosphere by recovering waste gas to be reused in the production process. However, flare gas recovery 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 Particulate Control Options for the Flares
As explained in Step 1, flare gas recovery is not feasible to control particulate emissions from the flares.

Step 3 – Rank Remaining Particulate Control Technologies for the Flares
Agrium has proposed the remaining two technically feasible control options for the flares EUs 11, 22, and 23. Therefore, ranking is not required.

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

Applicant Proposal

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) Particulate emissions from the ammonia tank flare, small flare, and emergency flare shall not exceed 7.6 lb/MMscf (0.0075 lb/MMBtu), during normal operation, based on a three-hour average.

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

The Department's finding is that BACT for Particulate emissions from the flares is as follows:

(a) Venting to the ammonia tank flare EU 11, small flare EU 22, 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) Particulate emissions from the ammonia tank flare, small flare, and emergency flare shall not exceed 0.0075 lb/MMBtu (AP-42 Table 1-4.2, PM (Total) for natural gas combustion converted to lb/MMBtu) during normal operation, based on a three-hour average.

6.6 Particulate BACT for the Well Pump and Fire Pump Engine (EUs 65 and 66)

Possible particulate emission control technologies for limited use internal combustion engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17:210: Small Fuel Oil-Fired Internal Combustion Engines (<500 hp) and 17:220: Small Other Liquid Fuel & Liquid Fuel Mixtures-Fired Internal Combustion Engines (<500 hp). The search results are summarized below:

Particulate Controls for Small Diesel-Fired Engines		
Control Technology	**Number of Determinations**	**Emission Limits (g/hp-hr)**
Diesel Particulate Filter	2	0.15
Federal Emission Standards, Good Combustion Practices, & Clean Fuel	89	0.075 – 0.40
Limited Operation	2	0.15
No Control Specified	32	0.11 – 1.0

Particulate Controls for Small Gasoline-Fired Engines		
Control Technology	**Number of Determinations**	**Emission Limits (lb/MMBtu)**
Limited Operation	1	0.1

Step 1 – Identify Particulate Control Technologies for the Pump Engines

From research, the Department identified the following technologies as available for particulate control of the pump engines:

(a) Diesel Particulate Filter (DPF)
DPFs are a control technology that are designed to physically filter particulate matter from the exhaust stream. Several designs exist which require cleaning and replacement of the filter media after soot has become caked onto the filter media. Regenerative filter designs are also available that burn the soot on a regular basis to regenerate the filter media. The Department considers DPF a technically feasible control technology for the diesel-fired well pump engine.

(b) Positive Crankcase Ventilation
Positive crankcase ventilation is the process of re-introducing the combustion air into the cylinder chamber for a second chance at combustion after the air has seeped into and collected in the crankcase during the downward stroke of the piston cycle. This process allows any unburned fuel to be subject to a second combustion opportunity. Any combustion products act as a heat sink during the second pass through the piston, which will lower the temperature of combustion and reduce the thermal NOx formation. The

Department considers positive crankcase ventilation a technically feasible control technology for the diesel-fired well pump engine.

(c) Federal Emission Standards
Federal emission standards require the engines meet the requirements of 40 C.F.R. 60 Subparts IIII and JJJJ, and 40 C.F.R 63 Subpart ZZZZ, or EPA tier certifications. Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. Subpart JJJJ applies to spark ignition internal combustion engines manufactured after various dates in the 2000s. EUs 65 and 66 are both manufactured prior to NSPS Subparts IIII and JJJJ, and NESHAP Subpart ZZZZ does not contain particulate emission limits for emergency engines at area sources of hazardous air pollutants (HAPs). Therefore the federal emission standards for particulates are not applicable to the pump engines.

(d) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. The pump engines are considered limited use EUs and both have existing permit limits of 168 hours per 12 consecutive month period. Therefore, the Department considers limited operation a technically feasible control technology for the pump engines.

(e) Good Combustion Practices (GCP) and clean fuel
The theory of GCPs and clean fuel was discussed in detail in NOx BACT section for the turbines and will not be repeated here. The Department's search of the RLBC database indicated that GCPs and clean fuel are commonly used to control particulate emissions for small diesel and gasoline-fired engines. Therefore, the Department considers GCPs and clean fuel to be a technically feasible control technology for the pump engines.

Step 2 – Eliminate Technically Infeasible Particulate Control Options for the Pump Engines
As explained in Step 1, The Department does not consider federal emission standards as technically feasible to control particulate emissions from the pump engines.

Step 3 – Rank Remaining Particulate Control Technologies for the Pump Engines
The following control technologies have been identified and ranked for control of particulate emissions from the pump engines.

(a) Limited Operation	(94% Control)
(b) Diesel Particulate Filters	(85% Control)
(c) GCPs & Clean Fuel	(Less than 40% Control)
(d) Positive Crankcase Ventilation	(10% Control)

Step 4 – Evaluate the Most Effective Controls
Limited operation is the most effective particulate control for small internal combustion engines. Since limited operation is not an add-on control, there is no additional environmental impacts.

RBLC Review

A review of similar units in the RBLC indicates good combustion practices and clean fuel, limited operation, diesel particulate filters, and federal emission standards are the principle particulate control technologies for the diesel-fired and gasoline-fired pump engines.

Applicant Proposal
The applicant proposes the following as BACT for particulate emissions from the pump engines:

(a) Particulate 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) Particulate emissions from the diesel-fired well pump EU 65 shall not exceed 0.31 lb/MMBtu;

(c) Particulate emissions from the gasoline-fired fire water pump EU 66 shall not exceed 0.10 lb/MMBtu; and

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

Step 5 – Selection of Particulate BACT for the Well Pump and Fire Water Pump Engines
The Department's finding is that BACT for VOC emissions from the well pump and fire pump engines is as follows:

(a) Limit operation of EUs 65 and 66 to no more than 168 hours each, in any 12 consecutive month period;

(b) VOC emissions from the diesel-fired well pump engine EU 65 will not exceed 0.31 lb/MMBtu (AP-42 Table 3.3-1, PM-10 emissions for uncontrolled diesel engines);

(c) VOC emissions from the gasoline-fired fire pump engine EU 66 will not exceed 0.10 lb/MMBtu (AP-42 Table 3.3-1, PM-10 emissions for uncontrolled gasoline engines); and

(d) Compliance with the proposed limits will be demonstrated by recording and reporting operating hours for the pump engines.

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

Possible particulate emission control technologies for the urea granulation process were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years with the process name containing the words *urea granulation* or *urea granulator*. The search results are summarized below:

Particulate Controls for Urea Granulation Vents		
Control Technology	**Number of Determinations**	**Emission Limits (lb/ton of urea produced)**
Wet Scrubber	24	0.005 – 0.67
No Control Specified	3	0.096 – 0.11

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

(a) 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/ft3 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/ft3 and have control efficiencies between 99% and 99.9%. 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. Additionally, there were no urea granulators in the RBLC using ESPs. Therefore, the use of ESPs is not a technologically feasible control option.

(b) Baghouse
The theory of baghouses were discussed in detail in the particulate matter BACT section for the primary reformer 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 process due to bag fouling causing excessive maintenance problems. Additionally, there were no urea granulators in the RBLC using baghouses. Therefore, the Department does not consider baghouses a technically feasible control technology for the urea granulation process.

(c) Wet Scrubber
The theory of wet scrubbers were discussed in detail in the particulate matter BACT section for the primary reformer and will not be repeated here. The majority of urea granulators in the RBLC use wet scrubbers to control particulates. Therefore, the Department considers the use of wet scrubbers a technically feasible control technology for the urea granulators.

Step 2 – Eliminate Technically Infeasible Particulate Controls for the Urea Granulation
As explained in Step 1, baghouses and ESPs are not considered technically feasible particulate control options for the urea granulation process.

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

Step 4 - Evaluate the Most Effective Controls
Installation of a wet scrubber will reduce particulate emissions from the urea granulation process while having minimal energy and environmental impacts. This system requires water for scrubbing and produces a waste effluent that can be treated for reuse.

RBLC Review
A review of similar units in the RBLC indicates wet scrubbers are the principle particulate control devices installed on urea granulators.

Applicant Proposal
The applicant proposes the following as BACT for particulate emissions from the urea granulation process:

(a) Particulate emissions from the operation of the urea granulators EUs 35 and 36 shall be controlled with the use of wet scrubbers; and

(b) Particulate emissions from the urea granulators EUs 35 and 36 shall not exceed 0.20 lb/ton of urea produced

Step 5 – Selection of PM BACT for the Urea Granulation
The Department's finding is that BACT for particulate emissions from the urea granulation process is as follows:

(a) Particulate emissions from the operation of the urea granulators EUs 35 and 36 shall be controlled with the use of wet scrubbers;

(b) Particulate emissions from the urea granulators EUs 35 and 36 shall not exceed 0.20 lb/ton of urea produced; and

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

6.8 Particulate BACT for the Urea Ship Loading (EU 47)
Possible particulate emission control technologies for urea ship loading were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years with the process name containing the words *urea loading* or *urea ship loading*. The search results are summarized below:

Particulate Controls for Urea Loading			
Source	**Control Technology**	**Particulate Size**	**Emission Limits (lb/ton loaded)**
Kenai Nitrogen Operations	Use of UF-85 (Hardening Agent), Product Coolers on Granulation Urea Process Lines, Loading into Partial Enclosure, and use of a Telescoping Chute	Total Particulates	0.0013
		PM-10	0.0011
		PM-2.5	0.00040
Port Neal Nitrogen Complex	Bin Vent Filter	Total Particulates	0.0030
		PM-10	0.0011
		PM-2.5	0.0011

Step 1 – Identify Particulate Control Technologies for Urea Ship Loading
Other than the KNO facility, the Department only identified one source in the RBLC with urea loading, the Port Neal Nitrogen Complex (RBLC ID IA-106). This facility has two loadouts; one for trains and one for trucks, and has a bin vent filter listed as a control device. The table above lists the emission limits for the Port Neal Nitrogen Complex, which are the same for PM-10 as the KNO facility and less stringent for total particulates and PM-2.5. Further, there is no practical

means to fully capture emissions during the ship loading process in order to direct them to a control device. Therefore, the combination of control devices used at the KNO facility is considered the only technically feasible control devices for urea ship loading.

Step 2 - Eliminate Technically Infeasible Particulate Controls for Urea Ship Loading
As explained in Step 1, the bin vent filter is not considered a technically feasible particulate control option for the urea ship loading process.

Step 3 - Ranking of Remaining Particulate Control Technologies for Urea Ship Loading
The applicant has proposed the only feasible control option. Therefore, ranking is not required.

Step 4 - Evaluate the Most Effective Controls

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[5] 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*"[6] 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.

Applicant Proposal
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. Using the adjusted ship loading emission factors that result from

[5] "Rock Crushing Plants", Texas Commission on Environmental Quality, Table 7
[6] 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.

manufacturing techniques, loading into enclosed holds, and use of a telescoping chute; the following table lists the proposed particulate matter BACT limits:

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	0.0013 lb/ton of urea
PM-10	0.017 lb/ton of urea	0.0085 lb/ton of urea	0.00425 lb/ton of urea	0.0011 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	0.0004 lb/ton of urea

The applicant proposes the following as BACT for particulate emissions from the urea ship loading process:

(a) Particulate 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) Particulate emissions from ship loading operations shall not exceed 0.0013 lb/tons of urea;

(c) Particulate emissions from ship loading operations shall not exceed 0.0011 lb/tons of urea; and

(d) Particulate emissions from ship loading operations shall not exceed 0.0004 lb/tons of urea.

Step 5 – Selection of Particulate BACT for the Urea Ship Loading

The Department's finding is that BACT for particulate emissions from urea ship loading EU 47 is as follows:

(a) Particulate 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) Particulate emissions from ship loading operations shall not exceed 0.0013 lb/tons of urea;

(c) Particulate emissions from ship loading operations shall not exceed 0.0011 lb/tons of urea; and

(d) Particulate emissions from ship loading operations shall not exceed 0.0004 lb/tons of urea.

6.9 Particulate BACT for the Urea Handling Units (EUs 47B through 47D)

Possible particulate emission control technologies for urea handling units were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years with the process name containing the words *urea handling*. The only results in the RBLC was for the KNO facility's previous Construction Permit AQ0083CPT06.

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

(a) Baghouse
The theory behind baghouses was discussed in detail in the particulate BACT section for the primary reformer and will not be repeated here. The KNO facility's previous construction permit selected a baghouse as a BACT control for the urea handling units. Therefore, this is considered 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
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 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 - Eliminate Technically Infeasible Particulate Controls for the Urea Handling Units
As explained in Step 1, water application is not considered as a technically feasible control option for particulate matter reduction of the urea handling units.

Step 3 - Rank Remaining Particulate 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) Baghouse (> 99% Control)
(b) HEPA Filters (> 99% Control)
(c) Cartridge Collectors (> 99% Control)

Step 4 - Evaluate the Most Effective Controls
Installation of a baghouse, cartridge collectors, or HEPA filters all control emissions from the urea handling process while having minimal energy and environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates a baghouse is the principle particulate control device installed on urea handling units.

Applicant Proposal
The applicant proposes the following as BACT:

(a) Particulate emissions from the operation of the urea material handling units shall be controlled with the use of baghouse filters; and

(b) Particulate emissions from the urea handling units shall not exceed 0.005 grains/dscf.

Step 5 – Selection of Particulate BACT for the Urea Handling Units (47B through 47D)
The Department's finding is that BACT for particulate emissions from the urea handling units is as follows:

(a) Particulate emissions from the operation of the urea handling units EUs 47B through 47D shall be controlled with the use of baghouse filters;

(b) Particulate emissions from the urea handling units EUs 47B through 47D shall not exceed 0.005 grains/dscf; and

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

6.10 Particulate BACT for the Two Cell Cross-Flow Cooling Tower (EU 40)
Possible particulate emission control technologies for the cooling tower were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years with the process name containing the words cooling tower. The search results are summarized below:

Particulate Controls for Cooling Towers		
Control Technology	**Number of Determinations**	**Emission Limits (% drift loss rate)**
Drift Eliminator	68	0.0005 – 0.005
No Control Specified	3	0.001

Step 1 – Identify Particulate Control Technologies for the Cooling Tower
From research, the Department identified the following control technologies as available for particulate control from cooling towers.

(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. Drift eliminators are the only control found for cooling towers in the RBLC and therefore are considered a technically feasible control option for the cooling tower.

(b) 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. However, this control technology is expensive and only used in areas of extreme water shortage. There were no cooling towers in the RBLC using dry cooling to control particulate emissions from cooling towers. Therefore, dry cooling is eliminated from further consideration.

Step 2 – Eliminate Technically Infeasible Particulate Controls for the Cooling Tower
As explained in Step 1, dry cooling systems are not considered technically feasible particulate control options for the cooling towers.

Step 3 – Rank Remaining Particulate Control Technologies for the Cooling Tower
The applicant has proposed the only feasible control option. Therefore, ranking is not required.

Step 4 - Evaluate the Most Effective Controls

RBLC Review
A review of similar units in the RBLC indicates drift eliminators are 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 (the lowest in the RBLC). 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
Agrium proposes to limit particulate emissions from the cooling tower EU 40 with a high efficiency drift eliminator designed with a drift loss rate of less than 0.002%.

Step 5 – Selection of Particulate BACT for the Cooling Tower
The Department’s finding is that BACT for particulate emissions from the cooling tower is as follows:

(a) Particulate emissions from the cooling tower EU 40 shall be controlled by operating and maintaining a high efficiency drift eliminator with a maximum drift of 0.002 percent of circulating water, at all times the EU is in operation; and

(b) Initial compliance with the proposed particulate emission limit will be demonstrated by supplying the Department with vendor data verifying that a high efficiency drift eliminator with a maximum drift of 0.002 percent of circulating water has been installed.

7.0 BACT DETERMINATION FOR GREEN HOUSE GASES

The KNO facility plans to install three gas-fired package boilers rated at 243 MMBtu/hr each, and five gas-fired Solar GSC-4701 turbine generator sets rated at 55.4 MMBtu/hr each that will be operated in combination with five existing gas-fired waste heat boilers to make five turbine cogeneration systems. Additionally, the KNO facility has previously installed one 1,350 MMBtu/hr primary reformer, flares, and several other EUs subject to BACT. The Department reviewed the control technologies Agrium identified in their application and determined CO_2 BACT for the EUs listed in Table B-5.

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.

The Department based its assessment on BACT determinations found in the RBLC and internet research. Table B-6 summarizes particulate BACT determinations in the RBLC in the last 10 years for the proposed EU types.

Table B-6: GHG BACT Determinations in RBLC

Description of GHG BACT	Cogeneration Gas Turbines	Primary Reformer	Package Boilers	Startup Heater	Pump Engines	Flares	CO_2 Vent
Good Combustion Practices, Energy Efficiency Measures & Clean Fuel	8	17	23	23	26		
Limited Operation			1	1	6		
Dry Low NOx Burners with Inlet Air Heating							
Proper Design and Good Combustion							
Selective Catalytic Reduction Controls							

Description of GHG BACT	Cogeneration Gas Turbines	Primary Reformer	Package Boilers	Startup Heater	Pump Engines	Flares	CO_2 Vent
Flare Work Practice Requirements and Minimization Plan						11	
Good Operational Practice including CO_2 reuse							11
NSPS Subpart IIII					3		
No Control Specified	3	2	3	3	4	2	4
Total	**11**	**19**	**27**	**27**	**39**	**13**	**15**

7.1 GHG BACT for the Cogeneration Turbines (EUs 55a – 59a) with Waste Heat Boilers (EUs 50 – 54)

Possible GHG emission control technologies for the cogeneration turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 16.210: small combined cycle and cogeneration natural gas-fired combustion turbines (≤25 MW). The search results are summarized below:

GHG Controls for Small Combined Cycle and Cogeneration Gas-Fired Turbines		
Control Technology	**Number of Determinations**	**Emission Limits (lb/MMBtu)**
Good Combustion Practices & Clean Fuel	8	42,268 – 155,597 tpy 117 – 118 lb/MMBtu
No Control Specified	3	119 lb/MMBtu 40,921 tpy

Step 1 – Identify GHG Control Technologies for the Cogeneration Turbines

From research, the Department identified the following technologies as available for GHG emissions control of gas-fired combined cycle and cogeneration combustion turbines rated at 25 MW or less:

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

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

combustor. The efficient combustion resulting from the process reduces the fuel consumption and CO_2 emissions.

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

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

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

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

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

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

The Department's research did not identify CCS as a control technology used to control GHG emissions from turbines or any other emission unit type installed at any facility in the RBLC database. However, the Department will advance this control technology to the next step to be evaluated.

(c) Good Combustion Practices (GCP) and Clean Fuels
The theory of good combustion practices was discussed in detail in the NOx BACT section for the turbines and will not be repeated here. GCP and clean fuels is a common technique for controlling GHG emissions. GHG emissions in the exhaust of liquid or gas-fired turbines are directly related to the carbon content in the fuel. Natural gas has the lowest amount of GHG emissions per Btu of energy of any fossil fuel, and is considered a feasible control technology for the power generation turbines.

Step 2 – Eliminate Technically Infeasible Control Options for Cogeneration Turbines
As explained in Step 1, ORC is not a feasible technology to control GHG emissions from cogeneration gas-fired turbines rated at 25 MW or less.

Aeroderivative turbine: the facility is currently designed to use five cogeneration turbines. Requiring the cogeneration turbines to be aeroderivative models would fundamentally redefine the source, and is therefore not considered as an option in the BACT analysis.

Step 3 – Rank Remaining Control Technologies for Cogeneration Turbines
The following control technologies have been identified and ranked for control of GHG from the cogeneration turbines:

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

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

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

Applicant Proposal
The applicant proposes the following as BACT for GHG emissions from the cogeneration turbines:

(a) Energy will be recovered through use of waste heat boilers;
(b) GHG emissions from the turbines and corresponding waste heat boilers shall not exceed 111.1 lb/MMBtu (56.7 tons/MMscf) from the turbines and 60.4. lb/MMBtu from the waste heat boilers (58.4 tons/MMscf weighted average) based on a three-hour average; and
(c) GHG emissions from the combination of all turbines and waste heat boilers shall not exceed 256,500 tpy.

Department Evaluation of BACT for GHG Emissions from Cogeneration Turbines
The Department used a study conducted by URS Corporation in 2010 titled, "Alaska Pipeline Project Gas Treatment Plant: CO_2 Capture Study" to make an economic analysis for the price of implementing CCS at Agrium's KNO facility. The CO_2 Capture Study for the Gas Treatment Plant included an estimated capital investment of $3.6 billion for implementation of CCS on the turbines at the facility. In the study, the estimated CO_2 emissions for the turbines at the Gas Treatment Plant were 4.38 billion tons per year, which is approximately twice the CO_2 emissions from all CO_2 emitting EUs at Agrium's KNO facility. Therefore, the Department's economic analysis for the KNO facility used a capital investment of $1.8 billion, which is half the capital investment from the Gas Treatment Plant study. The Department notes that through the principle of economies of scale this is a conservative assumption for capital investment. The Department's economic analysis used the current bank prime interest rate of 3.25%, an equipment life of 25 years, and assumed a 90% control of CO_2 emissions. A summary of the Department's cost analysis for all CO_2 emitting EUs at the KNO facility combined is shown below:

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
CCS	219,797.0	1,978,173	$1,815,877,000	$267,302,682	$135.1
Capital Recovery Factor = 0.0590 (3.25% for a 25 year life cycle)					

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

Step 5 – Selection of GHG BACT for the Cogeneration Turbines
The Department's finding is that BACT for GHG emissions from the cogeneration gas-fired combustion turbines rated at 25 MW or less is as follows:

(a) GHG emissions from EUs 55a – 59a and their associated waste heat boilers EUs 50 – 54 shall be minimized by maintaining good combustion practices and burning clean fuels at all times the units are in operation;

(b) GHG emissions from EUs 55a – 59a and their associated waste heat boilers EUs 50 – 54 shall not exceed 58.4 tons/MMscf[7] averaged over a 3-hour period (weighted average of AP-42 Tables 1.4-2, and 3.1-2a for CO_2, N_2O, and Methane for external combustion of natural gas and natural gas combustion in turbines converted to tons/MMscf); and

(c) GHG emissions from EUs 55a – 59a and their associated waste heat boilers EUs 50 – 54 shall not exceed shall not exceed 162,600 tons per twelve consecutive month period.

7.2 GHG BACT for the Primary Reformer (EU 12)
Possible GHG emission control technologies for the primary reformer were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years with the process name containing the word *reformer*. The search results were then filtered to include all relevant reformers with natural gas as the primary fuel input. The search results are summarized below:

GHG Controls for Reformer Furnaces		
Control Technology	**Number of Determinations**	**Emission Limits**
GCPs, Energy Efficiency Measures, and Clean Fuel	17	1.85 lb/ton NH3 3,284 – 1,614,575 tpy
No Control Specified	2	700,000 – 826,600 tpy

Step 1 – Identify GHG Control Technologies for the Primary Reformer
From research, the Department identified the following technologies as available for GHG emissions control of reformer furnaces:

(a) Cogeneration/Combined Heat and Power (CHP)

[7] The total CO_2e emissions rate is calculated with the equation $CO_2(1) + CH_4(25) + N_2O(298)$.

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 GHG BACT section for the cogeneration turbines and will not be repeated here. The Department's research did not identify CCS as a control technology used to control GHG emissions from reformer furnaces or any other emission unit type installed at any facility in the RBLC database. However, the Department will advance this control technology to the next step to be evaluated.

(c) Energy Efficiency Measures
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 (GCP) and Clean Fuel
The theory of GCPs was discussed in detail in the NOx BACT section for the turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of CO_2. Natural gas has the lowest amount of GHG emissions per Btu of energy of any fossil fuel, and is considered a feasible control technology for the primary reformer.

Step 2 – Eliminate Technically Infeasible Control Options for the Primary Reformer
As explained in Step 1, CHP is a technically infeasible GHG control technology for the primary reformer.

Step 3 – Rank Remaining Control Technologies for the Primary Reformer
The following control technologies have been identified and ranked for control of GHG from the primary reformer:

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

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

RBLC Review

A review of similar units in the RBLC indicates that clean fuels, good combustion practices, and energy efficiency measures are the only GHG emission control technologies currently installed on reformer furnaces.

Applicant Proposal
The applicant proposes the following as BACT for GHG emissions from the primary reformer:

(a) GHG emissions from the primary reformer shall not exceed 60.4 tons/MMscf 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) GHG 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.

Department Evaluation of BACT for GHG Emissions from Primary Reformer
The Department used a study conducted by URS Corporation in 2010 titled, "Alaska Pipeline Project Gas Treatment Plant: CO_2 Capture Study" to make an economic analysis for the price of implementing CCS at Agrium's KNO facility. The CO_2 Capture Study for the Gas Treatment Plant included an estimated capital investment of $3.6 billion for implementation of CCS on the turbines at the facility. In the study, the estimated CO_2 emissions for the turbines at the Gas Treatment Plant were 4.38 billion tons per year, which is approximately twice the CO_2 emissions from all CO_2 emitting EUs at Agrium's KNO facility. Therefore, the Department's economic analysis for the KNO facility used a capital investment of $1.8 billion, which is half the capital investment from the Gas Treatment Plant study. The Department notes that through the principle of economies of scale this is a conservative assumption for capital investment. The Department's economic analysis used the current bank prime interest rate of 3.25%, an equipment life of 25 years, and assumed a 90% control of CO_2 emissions. A summary of the Department's cost analysis for all CO_2 emitting EUs at the KNO facility combined is shown below:

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
CCS	219,797.0	1,978,173	$1,815,877,000	$267,302,682	$135.1
Capital Recovery Factor = 0.0590 (3.25% for a 25 year life cycle)					

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

Step 5 – Selection of GHG BACT for the Primary Reformer
The Department's finding is that BACT for GHG emissions from the primary reformer is as follows:

(a) GHG emissions from EU 12 shall be minimized by burning clean fuel and by maintaining good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation;

(b) GHG emissions from EU 12 shall not exceed 60.4 tons/MMscf[7] averaged over a 3-hour period (AP-42 Table 1-4.2, CO_2, N_2O (uncontrolled), and methane); and

(c) GHG emissions from EU 12 shall not exceed 700,000 tons per twelve consecutive month period.

7.3 GHG BACT for the Package Boilers (EUs 44a, 48a, and 49a)

Possible GHG emission control technologies for the package boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.310: Industrial Sized Natural Gas-Fired Boilers/Furnaces (>100 MMBtu/hr and <250 MMBtu/hr). The search results are summarized below:

GHG Controls for Industrial Sized Gas-Fired Boilers/Furnaces		
Control Technology	**Number of Determinations**	**Emission Limits**
GCPs and Clean Fuel	23	117 lb/MMBtu 638 – 1,148,305 tpy
Limited Use	1	200 hr/yr, 59.61 tons/MMscf
No Control Specified	3	73,058 – 127,981 tpy 59.61 MMscf

Step 1 – Identify GHG Control Technologies for the Package Boilers

From research, the Department identified the following technologies as available for GHG emissions 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 GHG BACT section for the cogeneration turbines and will not be repeated here. The Department's research did not identify CCS as a control technology used to control GHG emissions from boilers or any other emission unit type installed at any facility in the RBLC database. However, the Department will advance this control technology to the next step to be evaluated.

(c) Energy Efficiency Measures
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 (GCP) and Clean Fuels
The theory of GCP was discussed in detail in the NOx BACT section 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 GHG Control Options for the Package Boilers
As explained in Step 1, cogeneration/combined heat and power are not feasible technologies to control GHG emissions from the package boilers.

Step 3 – Rank Remaining GHG Control Technologies for the Package Boilers
The following control technologies have been identified and ranked for control of GHG from the package boilers:

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

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

RBLC Review
A review of similar units in the RBLC indicates that clean fuels and good combustion practices are the only GHG emission control technologies currently installed on gas-fired boilers/furnaces rated between 100 and 250 MMBtu/hr.

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) GHG emissions from the package boilers shall not exceed 60.2 tons/MMscf of natural gas combusted based on a three-hour average.

(c) GHG 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.

Department Evaluation of BACT for GHG Emissions from Package Boilers
The Department used a study conducted by URS Corporation in 2010 titled, “Alaska Pipeline Project Gas Treatment Plant: CO_2 Capture Study” to make an economic analysis for the price of

implementing CCS at Agrium's KNO facility. The CO_2 Capture Study for the Gas Treatment Plant included an estimated capital investment of \$3.6 billion for implementation of CCS on the turbines at the facility. In the study, the estimated CO_2 emissions for the turbines at the Gas Treatment Plant were 4.38 billion tons per year, which is approximately twice the CO_2 emissions from all CO_2 emitting EUs at Agrium's KNO facility. Therefore, the Department's economic analysis for the KNO facility used a capital investment of \$1.8 billion, which is half the capital investment from the Gas Treatment Plant study. The Department notes that through the principle of economies of scale this is a conservative assumption for capital investment. The Department's economic analysis used the current bank prime interest rate of 3.25%, an equipment life of 25 years, and assumed a 90% control of CO_2 emissions. A summary of the Department's cost analysis for all CO_2 emitting EUs at the KNO facility combined is shown below:

Control Alternative	**Potential to Emit (tpy)**	**Emission Reduction (tpy)**	**Total Capital Investment (\$)**	**Total Annualized Costs (\$/year)**	**Cost Effectiveness (\$/ton)**
CCS	219,797.0	1,978,173	\$1,815,877,000	\$267,302,682	\$135.1
Capital Recovery Factor = 0.0590 (3.25% for a 25 year life cycle)					

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

Step 5 – Selection of GHG BACT for the Package Boilers
The Department's finding is that BACT for GHG emissions from the package boilers is as follows:

(a) GHG emissions from EUs 44a, 48a, and 49a shall be minimized by burning clean fuel and by maintaining good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation;

(b) GHG emissions from EUs 44a, 48a, and 49a shall not exceed 60.2 tons/MMscf[7] averaged over a 3-hour period (AP-42 Table 1-4.2, CO_2, N_2O (controlled-low-NOx-burner), and methane); and

(c) GHG emissions from EU 12 shall not exceed 376,500 tons per twelve consecutive month period.

7.4 GHG BACT for the Startup Heater (EU 13)

Possible GHG emission control technologies for the startup heater were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 12.310: Industrial Sized Natural Gas-Fired Boilers/Furnaces (>100 MMBtu/hr and <250 MMBtu/hr). The search results are summarized below:

GHG Controls for Industrial Sized Gas-Fired Boilers/Furnaces		
Control Technology	**Number of Determinations**	**Emission Limits**
GCPs and Clean Fuel	23	117 lb/MMBtu 638 – 1,148,305 tpy
Limited Use	1	200 hr/yr, 59.61 tons/MMscf
No Control Specified	3	73,058 – 127,981 tpy 59.61 MMscf

Step 1 – Identify GHG Control Technologies for the Startup Heater
From research, the Department identified the following technologies as available for GHG control of startup heaters:

(a) Carbon Capture and Storage
The theory of CCS was discussed in detail in the GHG BACT section for the cogeneration turbines and will not be repeated here. The Department's research did not identify CCS as a control technology used to control GHG emissions from heaters or any other emission unit type installed at any facility in the RBLC database. However, the Department will advance this control technology to the next step to be evaluated.

(b) Good Combustion Practices (GCP) and Clean Fuels
The theory of GCP was discussed in detail in the NOx BACT section 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.

(c) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. The startup heater has an existing permit limit of 200 hours per 12 consecutive month period. Therefore, the Department considers limited operation a technically feasible control technology for the startup heater.

Step 2 – Eliminate Technically Infeasible GHG Control Options for the Startup Heater
As explained in Step 1, CCS is a technically infeasible control technology for the source.

Step 3 – Rank Remaining GHG Control Technologies for the Startup Heater
The following control technologies have been identified and ranked for control of GHG from the startup heater:

(a) Limited operation (97% Control)
(b) CCS (80% - 90% Control)
(c) GCP and Clean Fuels (<80% Control)

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

RBLC Review
A review of similar units in the RBLC indicates that clean fuels and good combustion practices are the only GHG emission control technologies currently installed on gas-fired boilers/furnaces rated between 100 and 250 MMBtu/hr.

Applicant Proposal
The applicant proposes the following as BACT:

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

(b) GHG emissions from the startup heater shall not exceed 60.4 tons/MMscf 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) GHG 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 GHG limits will be determined by tracking operating hours for the startup heater.

Step 5 – Selection of GHG BACT for the Startup Heater
The Department's finding is that BACT for GHG emissions from the startup heater is as follows:

(a) GHG emissions from EU 13 shall be minimized by burning clean fuel and by maintaining good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation;

(b) GHG emissions from EU 13 shall not exceed 60.4 tons/MMscf[7] averaged over a 3-hour period (AP-42 Table 1-4.2, CO_2, N_2O (uncontrolled), and methane); and

(c) GHG emissions from EU 13 shall not exceed 1,200 tons per twelve consecutive month period.

7.5 GHG BACT for the Ammonia Tank Flare and Small Flares (EUs 11, 22, and 23)
Possible GHG emission control technologies for the flares were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 19: Miscellaneous combustion (19:300 is specific to flares) and 50: Petroleum/Natural Gas Production and Refining. The search results were then filtered to include only emissions units with flares. The search results are summarized below:

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

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

(a) Flare Work Practice Requirements
Flare work practice requirements can be found in 40 CFR 60.18 (c) 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 GHG Control Options for the Flares
As explained in Step 1, flare gas recovery is not feasible to control GHG emissions from the flares.

Step 3 – Rank Remaining GHG Control Technologies for the Flares
Agrium has proposed the remaining two technically feasible control options for the flares EUs 11, 22, and 23. Therefore, ranking is not required.

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

Applicant Proposal
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) GHG emissions from the ammonia tank flare, small flare, and emergency flare shall not exceed 60.2 tons/MMBtu, during normal operation, based on a three-hour average.

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

The Department's finding is that BACT for GHG emissions from the flares is as follows:

(a) Venting to the ammonia tank flare EU 11, small flare EU 22, 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) GHG emissions from the ammonia tank flare, small flare, and emergency flare shall not exceed 60.2 tons/MMscf[7] (40 CFR Part 98: Appendix Tables C-1 and C-2 for natural gas) during normal operation, based on a three-hour average; and

(e) GHG emissions from the ammonia tank flare, small flare, and emergency flare shall not exceed 1,500 tons per twelve consecutive month period combined.

7.6 GHG BACT for the Well Pump and Fire Pump Engine (EUs 65 and 66)

Possible GHG emission control technologies for limited use internal combustion engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17:210: Small Fuel Oil-Fired Internal Combustion Engines (<500 hp) and 17:220: Small Other Liquid Fuel & Liquid Fuel Mixtures-Fired Internal Combustion Engines (<500 hp). The search results are summarized below:

GHG Controls for Small Diesel-Fired Engines		
Control Technology	**Number of Determinations**	**Emission Limits (tpy)**
Good Combustion Practices	26	0.29 – 3,083
NSPS IIII	3	10 – 72
Limited Operation	5	5 – 58
No Control Specified	4	9 – 516

GHG Controls for Small Gasoline-Fired Engines		
Control Technology	**Number of Determinations**	**Emission Limits (tpy)**
Limited Operation	1	27.2

Step 1 – Identify GHG Control Technologies for the Pump Engines

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

(a) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. The pump engines are considered limited use EUs and both have existing permit limits of 168 hours per 12 consecutive month period. Therefore, the Department considers limited operation a technically feasible control technology for the pump engines.

(b) Federal emission standards require the engines meet the requirements of 40 C.F.R. 60 Subparts IIII and JJJJ, and 40 C.F.R 63 Subpart ZZZZ, or EPA tier certifications. Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. Subpart JJJJ applies to spark ignition internal combustion engines manufactured after various dates in the 2000s. EUs 65 and 66 are both manufactured prior to NSPS Subparts IIII and JJJJ and NESHAP Subpart ZZZZ does contain GHG emission limits. Therefore the federal emission standards for GHG are not applicable to the pump engines.

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

The theory of GCPs and clean fuel was discussed in detail in the NOx BACT section for the turbines and will not be repeated here. The Department considers GCPs and clean fuel a technically feasible control technology for the pump engines.

Step 2 – Eliminate Technically Infeasible GHG Control Options for the Pump Engines
As explained in Step 1, federal emission standards are not feasible to control GHG emissions from the pump engines.

Step 3 – Rank Remaining GHG Control Technologies for the Pump Engines
The applicant has proposed the remaining two technically feasible control options for the pump engines EUs 65 and 66. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
Limited operation is the most effective GHG control for small internal combustion engines. Since limited operation is not an add-on control, there is no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates good combustion practices, limited operation, and federal emission standards are the principle GHG control technologies for both diesel-fired and gasoline-fired pump engines.

Applicant Proposal
The applicant proposes the following as BACT:

(a) GHG 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) GHG emissions from the diesel-fired well pump shall not exceed 164 lb/MMBtu, based on a three-hour average;
(c) GHG emissions from the gasoline-fired fire water pump shall not exceed 154 lb/MMBtu, based on a three-hour average; and
(d) The hours of operation for EUs 65 and 66 shall not exceed 168 hours each per year, each.

Step 5 – Selection of GHG BACT for the Pump Engines
The Department's finding is that BACT for GHG emissions from the well pump and fire pump engines is as follows:

(a) Limit operation of EUs 65 and 66 to no more than 168 hours each, in any 12 consecutive month period;
(b) GHG emissions from the diesel-fired well pump engine EU 65 will not exceed 164 lb/MMBtu (CO_2e emissions rate[8] for burning distillate fuel oil No. 2 in 40 CFR Part 98: Mandatory Greenhouse Gas Reporting);
(c) GHG emissions from the diesel-fired well pump engine EU 65 will not exceed 37.2 tons in any 12 consecutive month period;

[8] The total CO_2e emissions rate is calculated with the equation $CO_2(1) + CH_4(25) + N_2O(298)$.

(d) GHG emissions from the gasoline-fired fire pump engine EU 66 will not exceed 156 lb/MMBtu (CO_2e emissions rate for burning motor gasoline in 40 CFR Part 98: Mandatory Greenhouse Gas Reporting);

(e) GHG emissions from the gasoline-fired fire pump engine EU 66 will not exceed 27.5 tons in any 12 consecutive month period; and

(f) Compliance with the proposed emission limit will be demonstrated by recording and reporting operating hours for the pump engines.

7.7 GHG BACT for the CO_2 Vent (EU 14)

Possible GHG emission control technologies for the CO_2 vent were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 61.012: fertilizer production and 62.999: other inorganic chemical manufacturing. The search results were then filtered to include all relevant CO_2 vents. The search results are summarized below:

GHG Controls for CO_2 Vent		
Control Technology	**Number of Determinations**	**Emission Limits**
Good Operating Practices	11	73.13 tons/hr 267,584 – 1,226,814 tons/yr
No Control Specified	4	1,929 tons/hr 709,700 – 845,486 tons/yr

Step 1 – Identify GHG Control Technologies for the CO_2 Vent

The Department has identified the following control technologies for the CO_2 purification process.

(a) Carbon Capture and Storage (CCS)
The theory of CCS was discussed in detail in the CO_2 BACT section for the cogeneration turbines and will not be repeated here. The Department's research did not identify CCS as a control technology used to control GHG emissions from CO_2 vents or any other emission unit type installed at any facility in the RBLC database. However, the Department will advance this control technology to the next step to be evaluated.

(b) Good Operating Practices
Good operational practices includes energy efficiency measures and the recover and reuse of CO_2 in system processes. 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 GHG Control Options for the CO_2 Vent

All control technologies presented in Step 1 are considered technically feasible and advanced to the next step.

Step 3 – Rank Remaining GHG Control Technologies for the CO_2 Vent

The following control technologies have been identified and ranked for control of GHG from the CO_2 vent:

(a) CCS (80% - 90% Control)
(b) Good Operating Practices (<80% Control)

Step 4 – Evaluate the Most Effective Controls
Good operating practices including the recovery and reuse of CO_2 will reduce GHG emissions from the CO_2 vent while having minimal energy and environmental impacts.

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 for GHG emissions from the CO_2 vent:

(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) GHG 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.

Department Evaluation of BACT for GHG Emissions from CO2 vent
The Department used a study conducted by URS Corporation in 2010 titled, "Alaska Pipeline Project Gas Treatment Plant: CO_2 Capture Study" to make an economic analysis for the price of implementing CCS at Agrium's KNO facility. The CO_2 Capture Study for the Gas Treatment Plant included an estimated capital investment of $3.6 billion for implementation of CCS on the turbines at the facility. In the study, the estimated CO_2 emissions for the turbines at the Gas Treatment Plant were 4.38 billion tons per year, which is approximately twice the CO_2 emissions from all CO_2 emitting EUs at Agrium's KNO facility. Therefore, the Department's economic analysis for the KNO facility used a capital investment of $1.8 billion, which is half the capital investment from the Gas Treatment Plant study. The Department notes that through the principle of economies of scale this is a conservative assumption for capital investment. The Department's economic analysis used the current bank prime interest rate of 3.25%, an equipment life of 25 years, and assumed a 90% control of CO_2 emissions. A summary of the Department's cost analysis for all CO_2 emitting EUs at the KNO facility combined is shown below:

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
CCS	219,797.0	1,978,173	$1,815,877,000	$267,302,682	$135.1
Capital Recovery Factor = 0.0590 (3.25% for a 25 year life cycle)					

The Department's economic analysis, combined with the fact that there are no examples of CCS being used to control GHG emissions from any facility in the RBLC, indicates the level of GHG reduction does not justify the use of CCS as BACT for the CO_2 vent at the KNO facility.

Step 5 – Selection of GHG BACT for the CO_2 Vent
The Department's finding is that BACT for GHG emissions from the CO_2 vent is as follows:

(a) GHG emissions from the CO_2 vent EU 14 shall be controlled by maintaining good operating practices at all times the EU is in operation; and

(b) GHG emissions from the CO_2 vent EU 14 shall not exceed 845,486 tons per year.

APPENDIX C: MODELING REPORT

Alaska Department of Environmental Conservation

Air Permit Program

Review of **Agrium US Inc.'s Ambient Demonstration** for the **Kenai Nitrogen Operations Plant**

Construction Permit AQ0083CPT07

Prepared by: Jesse R. Jack
DRAFT: November 20, 2020

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1. INTRODUCTION

This report summarizes the Alaska Department of Environmental Conservation's (Department's) findings regarding the ambient analysis submitted by Agrium US Inc. (Agrium) for the Kenai Nitrogen Operations Plant (KNO). Agrium submitted this analysis in support of their May 21, 2019 Prevention of Significant Deterioration (PSD) permit application (AQ0083CPT07). The project triggers PSD review for oxides of nitrogen (NOx), particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns or less (PM-10), particulate matter with an aerodynamic diameter of 2.5 microns or less (PM-2.5), carbon monoxide (CO), volatile organic compounds (VOC), ozone (O_3), and greenhouse gases (GHG).

Agrium provided 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 demonstrated that operating the KNO emissions units (EUs) within the restrictions listed in this report will not cause or contribute to a violation of the following Alaska Ambient Air Quality Standards (AAAQS) established in 18 AAC 50.010: one-hour and NO_2, 24-hour PM-10, 24-hour and annual PM-2.5, one-hour and eight-hour CO, and eight-hour ammonia (NH_3). Agrium also demonstrated that the KNO impacts will not cause or contribute to a violation of the following Class II maximum allowable increases (increments) described in 18 AAC 50.020: annual NO_2, 24-hour and annual PM-10, and 24-hour and annual PM-2.5.[1]

The Department previously approved an ambient demonstration submitted by Agrium in support of AQ0083CPT06. The Department's findings regarding this previous modeling effort are documented in the November 26, 2014 report, *Review of Agrium's Ambient Demonstration for the Kenai Nitrogen Operations Restart Project*, which is included as Appendix D of the Technical Analysis Report (TAR) for AQ0083CPT06. **Today's report only addresses those items that have changed subsequent to that analysis, or that otherwise warrant discussion.**

2. PROJECT BACKGROUND

The Kenai Nitrogen Operations Plant is considered a new stationary source. KNO is an existing fertilizer manufacturing facility, but has been inoperative for several years. On October 26, 2009 the Department rescinded all previous air quality control permits at Agrium's request, and determined that the facility would be regulated as a new stationary source should operations resume. Agrium is proposing to restart a portion of the facility, and therefore must satisfy the applicable regulatory requirements for a new stationary source.

Agrium is proposing to operate equipment related to the production of liquid ammonia and granulated urea at KNO. They were previously issued Air Quality Control Construction Permit AQ0083CPT06 on January 6, 2015 to restart these production lines. However, Agrium has not yet resumed production at the facility, and is now proposing to modify the emissions units at KNO. The modifications include replacement of EUs 55 through 59 with higher-capacity

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

turbines; reducing the heat input of the waste heat boilers, EUs 50 through 54; and the installation of SCR to control NOx on the Package Boilers, EUs 44, 48 and 49. Additional information regarding the project, the triggered permit classifications, and the ambient demonstration requirements for those classifications are provided below.

2.1. Project Location and Area Classification

KNO is located at Mile 21 of the Kenai Spur Highway, near Kenai, Alaska. The area is unclassified in terms of 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 area,[2] Tuxedni National Wildlife Refuge (Tuxedni), is located approximately 90 kilometers (km) to the southwest. Denali National Park (Denali) is located approximately 200 km to the north.

2.2. Ambient Demonstration Requirements

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

- Stack Height considerations, per 40 CFR 52.21(h);
- 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 pollutants 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 PSD requirements for Class I areas warrants discussion. Section 165(d)(2)(A) of the Clean Air Act requires the permitting authority to notify the Federal Land Manager (FLM) of any PSD application that the permitting authority receives for a project that may impact a Class I area. The U.S. Environmental Protection Agency (EPA) has elaborated on this requirement by issuing guidance that says the permitting authority must provide timely notification of all PSD projects located within 100 km of the Class I area and or for "*very large [PSD] sources*" located beyond 100 km.[3]

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

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

The FLM will decide whether they want to be involved in the PSD project once they are notified of the project. Their approach for making this decision, and the types of assessments that they may ask for, is described in the 2010 version of the *Federal Land Manager's Air Quality Related Values Work Group (FLAG) Phase I Report.* The report details a screening procedure for stationary sources located beyond 50 km from the Class I area that allows the FLM to assess whether a PSD project is too small or too distant to warrant a Class I impact analysis.

Agrium used this emissions-to-distance (Q/d) screening procedure. The Q/d value for the nearest Class I areas, Tuxedni and Denali, are 6.2 and 2.7, respectively. The Department forwarded this information to the U.S. Fish and Wildlife Service (FWS) and the U.S. National Park Service (NPS) to solicit their interest in a May 23, 2019 email. FWS and NPS responded jointly by e-mail on June 27, 2019 and requested a Class I AQRV analysis. However, upon subsequent discussion with the Department and Agrium, FWS and NPS found that an AQRV analysis was not necessary "assuming that operations at this facility will be as well controlled as possible"[4].

2.3. Increments and Baseline Dates

An Increment reflects the maximum allowed increase in ambient concentration that may occur in a given area. They are determined relative to the "baseline concentration," which reflects the concentration that occurred, or was accounted, for at the time of a set baseline date. Congress set January 6, 1975 as the major source baseline date for the 24-hour and annual PM-10 increments, and the 3-hour, 24-hour, and annual SO_2 increments. EPA established February 8, 1988 as the major source baseline date for the annual NO_2 increment, and October 20, 2010 as the major source baseline date for the 24-hour and annual PM-2.5 increments. There are no 1-hour SO_2 or 1-hour NO_2 increments. The minor source baseline dates for the Cook Inlet Intrastate Air Quality Control Region are listed in Table 2 of 18 AAC 50.020.

2.4. Modeling Protocol Submittal

Agrium submitted a modeling protocol on February 7, 2019. ERM Group, Inc. (ERM), prepared the protocol on their behalf.

2.5. Application Submittal

The Department received Agrium's permit application and ambient demonstration on May 21, 2019. Agrium provided supplemental information via email on May 20, 2020.

3. 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

4 Email from Andrea Stacy (National Park Service) to Dave Jones (Department); *Re: Agrium US Inc. Kenai Nitrogen Operations PSD Construction Permit Application*, October 21, 2019

meeting the pre-construction monitoring requirement in 40 CFR 52.21(m) is described in Section 4.1 of this report (**Pre-Construction Monitoring Data)**. The Department's findings regarding the additional impact analysis under 40 CFR 52.21(o) is described in Section 8 (**Additional Impact Analysis)**.

Agrium used a variety of means to address the ambient demonstration requirement in 40 CFR 52.21(k). Agrium used computer analysis (modeling) with the AERMOD Modeling System (AERMOD) to predict the near-field ambient NO_2, PM-10, PM-2.5, CO and NH_3 air quality impacts. Agrium used a qualitative approach to address the ambient O_3 impacts. The Department's findings regarding these assessments are respectively in Section 5 (**Near-field AERMOD Analysis**), and Section 7 (**Ozone Impacts**).

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). The requirement only pertains to those pollutants that are subject to PSD review and have a National Ambient Air Quality Standard (NAAQS).[5] 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 requirement is discussed below. Agrium's approach for meeting the "background" data needs is described in the *Off-site Impact* sub-section of the *Near-field AERMOD Impact Analysis* section of this report.

4.1. Pre-Construction Monitoring

Pre-construction monitoring data must be collected at a location and in a manner that is consistent with EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA-450/4-87-007), which the Department adopted by reference in 18 AAC 50.035(a)(5). In summary, the data must be collected at the location(s) of existing and proposed maximum impacts, the data must be current, and the data must meet PSD quality assurance requirements. The current quality assurance requirements are described in 18 AAC 50.215(a).

Agrium fulfilled the pre-construction monitoring requirement for all PSD-triggered pollutants using the same approach as previously approved in their demonstration for AQ0083CPT06. In summary, the NO_2 impacts from KNO were found to be less than the applicable SMC. Agrium used previously-collected data from the Swanson River Field to represent CO concentrations, and collected site-specific ambient data at KNO to fulfill the pre-construction monitoring requirements for PM-10, PM-2.5 and O_3. The Department finds

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

that these data continue to meet the requirements of 18 AAC 50.035(a)(5) and that Agrium's approach remains acceptable. More details about their pre-construction monitoring demonstration can be found in Section 4.1 of the Department's 2015 modeling review.

5. NEAR-FIELD AERMOD IMPACT ANALYSIS

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 a qualitative approach to address the ambient O_3 impacts. The Department's findings regarding Agrium's ambient analysis are provided below. The Department's findings regarding the qualitative O_3 assessment is provided in the *Ozone Impact* section of this report.

5.1. Approach

Consistent with their 2014 analysis, Agrium identified four short-term operating scenarios that could occur during any given year. They modeled each of those four scenarios for those pollutants with a short-term AAAQS or increment, with the exception of the 1-hour NO_2 AAAQS. Each of these short-term scenarios were modeled twice, once each to represent impacts from a urea or NH3 ship loading that could occur during the scenario. For comparison to the annual increments and AAAQS, Agrium assumed all EUs would operate at their respective annual operating limit.

These operating scenarios are discussed in detail in the Department's 2014 review.

5.2. Model Selection

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 EPA's AERMOD Modeling System (AERMOD) for their ambient analysis. AERMOD is an appropriate modeling system for this permit application.

The AERMOD Modeling System consists of three major components: AERMAP, used to process terrain data and develop elevations for the receptor grid and EUs; AERMET, used to process the meteorological data; and the AERMOD dispersion model, used to estimate the ambient pollutant concentrations.

Agrium used the current version of AERMAP (version 18081). They also used the versions of AERMET and AERMOD that were current at the time they prepared their application (versions 18081). However, EPA updated AERMOD and AERMET on August 21, 2019. The latest versions are now AERMOD and AERMET versions 19191.

The Department reviewed EPA's Model Change Bulletins for these updates and determined that the revisions regard optional features, non-pertinent algorithms, and other changes that would not lead to increased impacts. Thus, none of the changes warrant an updated modeling analysis.

5.3. Modeling Domain

The modeling domain is used to help establish and limit the receptor grid and offsite emissions inventory. Agrium used a reasonable modeling domain for their ambient demonstration, consistent with their 2014 analysis. The modeling domain is described in Section 12 of that analysis.

5.4. Meteorological Data

AERMOD requires hourly meteorological data to estimate plume dispersion. A *minimum* of one-year of site-specific data, or five years of representative National Weather Service (NWS) data is required, per Section 8.4 of the Guideline. Representative data from the Federal Aviation Administration (FAA) may also be used if the accuracy and detail are equivalent to NWS data.

Agrium used five years (2008-2012) of FAA Automated Surface Observing System (ASOS) data from Kenai Regional Airport, along with concurrent upper air data from the nearest NWS upper air station, Anchorage. This dataset was used by Agrium in their May 2014 analysis, and originally processed by Hilcorp in support of a minor permit for the Paxton Production Pad; more information is available in the modeling reports attached to the Technical Analysis Reports (TARs) for AQ0083CPT06 and AQ1286MSS01. For the current analysis, Agrium obtained the meteorological data in AERMOD-ready format from the Department website. The Department had reprocessed in the latest version of AERMET, version 18081. The meteorological conditions at Kenai represent the plume transport conditions of the KNO EUs.

5.4.1. AERMINUTE

The NWS runs an ASOS at the Kenai Regional Airport. Data at one minute time-steps is therefore available for this site. Agrium used AERMINUTE version 15272 to pre-process the one-minute meteorological data. This is the current version of AERMINUTE. Agrium appropriately set the Ice Free Winds (IFW) setting to "yes" since the NWS used a sonic anemometer to measure the wind speed and direction.[6]

5.4.1. Low Wind Speed Adjustments

AERMET contains an option for adjusting the surface friction velocity (ADJ_u*) parameter. EPA developed this option to correct AERMOD's tendency to overpredict impacts under stable, low wind conditions. It is a regulatory option when used *without* turbulence measurements, such as standard deviation of horizontal wind direction (sigma-theta) data and/or standard deviation of vertical wind speed (sigma-W) data. Agrium reprocessed the Kenai surface meteorological data to use the ADJ_u* option in AERMET. The data set included turbulence measurements; however, they did not incorporate those values in the AERMET run.

[6] The sonic anemometer became operational on September 21, 2006.

5.5. 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 modeling analysis.

Agrium used the Universal Transverse Mercator (UTM) grid for their coordinate system. This is the most commonly used approach in AERMOD assessments. The UTM system divides the world into 60 zones, extending north-south, and each zone is 6 degrees wide in longitude. The modeled EUs, structures, and receptors are all located in UTM Zone 6. Agrium used the North American Datum of 1983 reference for each UTM coordinate.

5.6. Terrain

Terrain features can influence plume dispersion and the resulting ambient concentration. Digitized terrain elevation data is therefore generally included in a modeling analysis. AERMOD's terrain preprocessor, AERMAP, utilizes the terrain data to obtain the base elevations for the modeled EUs, buildings, and receptors; and to calculate a "hill height scale" for each receptor.

Agrium used National Elevation Dataset (NED) files with a 1/3 arc-second resolution for their terrain analysis. NED is the current terrain elevation dataset provided by the Unites States Geological Survey. This approach is acceptable.

5.7. EU Inventory

Agrium included each EU in their modeling analysis. They also included fugitive NH_3 emissions in their NH_3 modeling analysis. Agrium's approach to characterizing the KNO EUs is mostly consistent with their approach in their May 2014 analysis; the aspects that warrant further discussion are described below.

5.7.1. Increment Analysis

As previously discussed in the *Background* section of this report, KNO is located within a Class II area of the Cook Inlet Intrastate Air Quality Control Region. All permanent EUs at KNO were installed after the applicable baseline dates. Furthermore, KNO has been shut down for a number of years. Thus, all EUs are considered increment-consuming. Agrium included all of their permanent EUs in their increment analyses.

5.7.2. Secondary Emissions Inventory

PSD applicants must include "secondary emissions" in their ambient demonstration, per 40 CFR 52.21(k)(1). EPA defines the term in 40 CFR 52.21(b)(18) as, "*emissions which would occur as a result of the construction or operation of a major stationary source… but do not come from the major stationary source*…" However, secondary emissions do not include "*any emissions which come directly from a mobile source*." Subsequent EPA guidance further clarifies that the definition in 40 CFR 52.21(b)(18) "*sets out four tests to be used in determining whether such emissions are to be included in air quality* *impact assessments for PSD purposes: the emissions must be specific, well defined, quantifiable, and impact the same general area*."[7]

The restarting of KNO will lead to ship activity at the Agrium wharf. Agrium used the same approach to characterize these ship emissions as they did in their analysis submitted in support of AQ0083CPT06. Likewise, Agrium continued to omit construction activities from their analysis because most of the components of the project are already installed and the project will, therefore, require little construction activity. These approaches continue to be acceptable.

5.8. EU Release Parameters

The assumed emission rates and characterization of how the emissions enter the atmosphere can significantly influence the modeled results.

5.8.1. Emission Rates

The Department generally found Agrium's modeled emission rates to be consistent with the emissions information provided throughout their application. The exceptions, or items that otherwise warrant additional discussion, are discussed below. A discussion regarding turbine emissions is provided in the *Load Analysis* sub-section under EU Release Parameters.

5.8.1.1. Operational Limits

Agrium assumed that most combustion sources operate continuously throughout the year at the worst-case capacity. Except for the Solar Turbines (EUs 55a through 59a), Waste Heat Boilers (EUs 50 through 54), the Package Boilers (48a and 49a), the Well Pump Engine and the Fire Pump Engine (EUs 55 and 56, respectively) all EUs were modeled with identical parameters as in the 2014 analysis; thus, any operational limits that applies to the identically-modeled EUs will be carried forward from AQ0083CPT06. More details on those assumptions and operational limits can be found in Section 5.6.1 of the Department's 2014 review. Operational limits applicable to the new EUs are discussed in more detail below.

- The Well Pump Engine (EU 55) and Fire Pump Engine (EU 56) were modeled using an emission rate corresponding to 168 hours per year. The Department is imposing this assumption to protect the AAAQS and increments.
- Agrium modeled the Package Boilers (EUs 48a and 49a) assuming that they would employ SCR for control of NO_2. The Department is imposing this assumption as a requirement to protect the annual NO_2 AAAQS and increment.

[7] EPA letter from Edward F. Tuerk (Acting Assistant Administrator for Air, Noise and Radiation) to Allyn M. Davis (Director, Air and Hazardous Materials Division); *PSD Evaluation of Secondary Emissions for Houston Lighting and Power*; March 17, 1981.

5.8.1.2. Short-term Emission Rates

The modeled emission rate should generally reflect the maximum emissions allowed during the given averaging period. The operating scenarios discussed in Agrium's 2014 analysis included several short-term assumptions which necessitated limits to protect short-term AAAQS and Class II increments; these conditions are being carried forward from AQ0083CPT06 and imposed in AQ0083CPT07. Aside from those assumptions, Agrium used the maximum emissions, by pollutant and averaging period, to develop their modeled EU emission rates. Therefore, the Department is not including any additional operational restrictions for the KNO EUs.

5.8.1.3. Off-site Emissions

For the off-site sources previously modeled in their October 2014 analysis, Agrium reviewed the permit record to determine if any changes had occurred and updated their modeled sources accordingly. For the off-site sources that were not included in the October 2014 analysis, Agrium obtained the emission rates for the modeled off-site sources from the Department. The Department finds that Agrium's emission rates sufficiently represent off-site sources.

5.8.2. Point Source Parameters

In addition to the previously discussed emission rates, applicants must provide the stack height, diameter, location, base elevation, exhaust plume exit velocity, and exhaust temperature for each EU characterized as a point source.

The Department generally found the modeled stack parameters to be consistent with the vendor information or expectations for similarly sized EUs. The items that otherwise warrant additional discussion are discussed below.

5.8.2.1. 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 previously conducted a load analysis for the existing emission units in their 2014 analysis. They conducted a load analysis of the new KNO turbines and waste heat boilers, EUs 50 through 59a, using the same methodology. Agrium found that the maximum impacts occur during 100% operating load. Therefore, Agrium used these emissions and stack parameters in their cumulative impact analysis. The Department agrees with these findings, and that the previous load analysis methods continue to be acceptable.

5.8.2.2. Stack Heights

As discussed in the Department's 2014 review, KNO has a number of tall structures that could lead to substantial downwash, and exhaust stacks with fairly high release points which enhances dispersion. The Department imposed corresponding minimum stack height conditions to protect ambient air quality and the increments in AQ0083CPT06. These stack heights were unchanged in Agrium's modeling analysis for AQ0083CPT07; the stack height requirements established in AQ0083CPT06 will therefore be carried forward to AQ0083CPT07. The stack height requirements and applicable pollutants are described in Table 1, below.

Table 1. 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

Aside from the above-mentioned stacks, the Department generally found the modeled stack heights to be consistent with those of similarly sized EUs.

5.8.2.3. Horizontal/Capped Stacks

Capped stacks or horizontal releases generally lead to higher impacts in the immediate near-field than what would occur from uncapped, vertical releases. The presence of non-vertical stacks or stacks with rain caps therefore requires special handling in an AERMOD analysis. EPA describes the proper approach for characterizing these types of stacks in their *AERMOD Implementation Guide*.[8] EPA has also developed an option in AERMOD that will automatically revise the stack and exhaust parameters for any stack identified as horizontal (using the POINTHOR keyword) or capped (using the POINTCAP keyword).

Agrium used this option to characterize their horizontal stacks. They characterized the scrubber (EU 41), the MDEA storage tanks (EUs 41B and 41C), the deaerator vent (EU 60), the well pump engine (EU 65), the fire pump engine (EU 66), and the urea storage warehouse baghouse (EUs 47C and 47D) as having horizontal

[8] *AERMOD Implementation Guide* (EPA-454/B-18-003); April 2018.

releases. They characterized all other KNO EUs as having uncapped, vertical releases. The Department is including a permit condition that requires the stacks modeled as uncapped, vertical releases to be constructed as uncapped, vertical releases.

5.8.2.4. Off-Site Source Stack Parameters

Aside from the off-site sources included in Agrium's 2014 analysis, regional and nearby off-site stationary sources were also modeled as single point sources. Due to the difficulty in obtaining unit-specific stack parameters for these sources, Agrium used a set of default stack parameters to represent offsite sources that were explicitly modeled. These parameters are listed in Table 2, below. The Department finds these stack parameters to be appropriate.

Table 2: Default Stack Parameters for Off-Site Sources

Source Parameter	Default Parameter Value
Stack Height	7.6 meters
Stack Diameter	1.07 meters
Exit Temperature	777 Kelvin
Exit Velociety	52.1 meters/second
Flow Rate	46.85 acm/s

5.8.3. Volume Source Parameters

The volume source option is frequently used to characterize fugitive emissions that have initial lateral and vertical spread near the point of release. Agrium continued to characterize the urea ship loading emissions (EU 47), and the urea warehouse and tripper belt emissions (EU 47B), as volume sources as described in Section 5.8.2.3 of the Department's review of their 2014 modeling. The Department finds this approach acceptable.

5.9. Pollutant Specific Considerations

The following pollutants warrant additional discussion.

5.9.1. Ambient NO_2 Modeling

The oxides of nitrogen (NOx) emissions from combustion sources are partly nitric oxide (NO) and partly NO_2. After the combustion gas exits the stack, additional NO_2 can be created due to atmospheric reactions. Section 4.2.3.4 of the Guideline describes a three-tiered approach for estimating the resulting ambient NO_2 concentrations, ranging from the simplest assumption that all NO is converted to NO_2, to other more complex methods.

Agrium used the Tier 2 approach, where AERMOD applies an ambient NO_2-to-NOx ratio to the 1-hour modeled NOx concentrations based on a formula empirically derived from ambient monitored NO_2-to-NOx ratios. The ARM2 option includes default upper and lower limits on the ambient ratio applied to the modeled NOx concentration of 0.9 and 0.5, respectively. Agrium used the default limits. This is appropriate for this project.

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).[9] AERMOD is an acceptable model for performing near-field analyses of the direct emissions, but EPA has not developed a near-field model that includes the necessary chemistry algorithms for estimating the secondary impacts. EPA instead recommends that applicants use "existing technical information" to assess the secondary impacts (aka a "Tier 1" analysis), or if warranted, a photochemical modeling analyses to assess the secondary impacts (aka a "Tier 2" analysis).[10] Tier 1 is the expected typical approach.

EPA noted in their May 2014 PM-2.5 modeling guidance 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.[11] 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 immediate near-field, which is where the maximum direct impacts from the KNO EUs occur.

Agrium continued to use the same approach to address secondary PM-2.5 formation as in their application for AQ0083CPT06. In the current analysis, they updated the data to reflect current emissions at KNO and nearby offsite stationary sources for comparison. Agrium reported that the potential precursor emissions from KNO are only a small percentage of the total NOx and SO_2 emissions in the area – 6.3% and 7.3%, respectively – and that the area is in attainment with the PM-2.5 AAAQS by a wide margin.

5.10. Downwash

Downwash refers to the situation where local structures influence the plume from an exhaust stack. Downwash can occur when a stack height is less than a height derived by a procedure called "Good Engineering Practice" (GEP), which is defined in 18 AAC 50.990(42). It is a consideration when there are receptors relatively near the applicant's structures and exhaust stacks.

EPA developed the "Building Profile Input Program - PRIME" (BPIPPRM) program to determine which stacks could be influenced by nearby structures and to generate the cross-

9 The NOx and SO_2 emissions are also referred as "precursor emissions" in a PM-2.5 assessment.
10 EPA's two-tiered approach for assessing secondary PM-2.5 formation is described in Section 5.4 of the Guideline.
11 *Guidance for $PM_{2.5}$ Permit Modeling* (EPA-454/B-14-001); May 2014.

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 all of their modeled point sources in their downwash analysis. They used the same approach that was used in their previous analysis. This approach remains acceptable.

5.11. Ambient Air Boundary

Agrium used the same ambient air boundary as in their previous analysis. The Department finds this approach to be acceptable for delineating ambient air.

5.12. Receptor Grid

A dispersion model will calculate the concentration of the modeled pollutant at locations defined by the user. These locations are called receptors.

Agrium continued to use the same receptor grid as they did in their 2014 analysis. The Department continues to find that this receptor grid has sufficient resolution and coverage to determine the maximum impact.

5.13. Off-Site Impacts

The air quality impact from natural and regional sources, along with long-range transport from far away sources, must be accounted for in a cumulative AAAQS demonstration. The increment consuming impact from nearby anthropogenic sources must likewise be accounted for in a cumulative increment demonstration. The approach for incorporating these impacts must be evaluated on a case-specific basis for each type of assessment and for each pollutant.

Section 8.3 of the Guideline discusses how the off-site impacts could be incorporated for purposes of demonstrating compliance with an air quality standard. In summary, the off-site impacts must either be represented through ambient monitoring data or through modeling. However, Section 8.3.3(b)(iii) notes, "*The number of nearby sources to be explicitly modeled in the air quality analysis is expected to be few except in unusual situations*." Section 8.3.3(b) further states, "*… sources that cause a significant concentration gradient in the vicinity of the [applicant's source] are not likely to be adequately characterized by the monitored data due to the high degree of variability of the source's impacts.*"

For their cumulative AAAQS demonstration, Agrium modeled the same off-site sources, using the same approach, as in their October 2014 analysis. These sources included the ConocoPhillips Alaska, Inc. LNG Plant, the Homer Electric power plant, the Tesoro Refinery, and the AE&EC Bernice Lake facility. They reviewed permits issued since October 2014 and updated the emissions rates and parameters based on that information. The Department finds Agrium's inventory of off-site sources acceptable for their cumulative AAAQS analysis.

Consistent with their approach in the modeling analysis for AQ0083CPT06, Agrium used the more refined temporarily-varying option for including the background concentration in their 1-hour NO_2 AAAQS demonstrations.

Agrium included a more comprehensive and detailed inventory of offsite sources for their increment analysis. For the annual NO_2, PM-2.5 and PM-10 increment analyses, Agrium explicitly modeled all off-site stationary sources within 1 km of the Significant Impact Area (SIA) of KNO. All stationary sources within 10 to 50 km of the SIA which emitted more than one tpy of the applicable pollutant in 2018 were also explicitly modeled.

An increment analysis should typically consider the change in emissions between the applicable baseline date(s), and those at the present. However, Agrium took the conservative approach of assuming that all nearby and regional off-site sources are increment-consuming, disregarding baseline actual emissions that existed at the applicable baseline dates.

For the 24-hour PM-10 and PM-2.5 increments, Agrium could not obtain short-term emissions rates for all offsite sources within 50 km of the SIA of KNO. Thus, their increment analysis for these pollutants represented four nearby stationary sources – the Nikiski Generating Plant, the Kenai LNG plant, the Tesoro Kenai Refinery, and the AE&EC Bernice Lake Power Plant – by explicit modeling, as these were the nearby sources that Agrium believed would be reasonably likely to contribute to the impacts from KNO.

The Department finds that, although Agrium was unable to model short-term impacts from as detailed an inventory of off-site sources as in their annual-average analyses, their 24-hour PM-10 and PM-2.5 increment analyses are adequate for demonstrating compliance with the Class II increments. In Agrium's original May 2019 analysis, they explicitly modeled the same four off-site sources for their annual-average increment analyses. Expanding the modeled inventory in their May 2020 analysis resulted in an increased annual PM-10 impact of 0.01 $\mu g/m^3$, and an increased annual PM-2.5 impact of 0.47 $\mu g/m^3$ as compared to Class II increments of 17 and 4 $\mu g/m^3$, respectively. Again, these modeled impacts assume that all sources are increment-consuming, and disregard baseline-date actual emissions. Therefore, the Department finds that the modeled inventory is sufficient for demonstrating compliance with the 24-hour PM-10 and PM-2.5 Class II Increments.

5.14. Modeled Design Concentrations

EPA allows applicants to use modeled concentrations that are consistent with the form of the standard or increment as the modeled design concentration. The highest concentrations must be used when comparing the modeled impacts to the deterministic annual average standards, increments, SILs and SMCs. Consistent with their 2014 analysis, Agrium used the modeled concentrations calculated as indicated in Table 3 for comparison to the SMCs, AAAQS, and Class II increments. The approach is consistent with the form of these standards and continues to be acceptable.

Table 3. Agrium's Approach for Determining The Modeled Design Concentrations

Pollutant	Avg. Period	SMC	AAAQS	Class II Increment
NO_2	1-hour	--	h8h	--
	Annual	HY	HY	HY
PM-10	24-hour	h1h	h6h	h2h
	Annual	--	--	HY
PM-2.5	24-hour	--	h8h	h2h
	Annual	--	MA	HY
CO	1-hour	--	h2h	--
	8-hour	h1h	h2h	--
NH_3	8-hour	--	H2h	

Table Notes:

h1h = the maximum high, second high concentration from any year.

h2h = the maximum high, second-high concentration from any year.

h4h = the multi-year average of the high, fourth-high daily maximum 1-hour concentrations.

h6h = the high, sixth-high 24-hour concentration 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-hour NO_2 concentrations. For purposes of 24-hour PM-2.5, the h8h is the five-year average of the high, eighth-high of the 24-hour PM-2.5 concentrations.

HY = highest annual average from any year.

MA = highest multi-year average of the annual concentrations at a given receptor. -- = there is no AAAQS/increment (as applicable) for this pollutant/averaging period.

6. RESULTS AND DISCUSSION

The maximum modeled NO_2, PM-2.5, PM-10, CO, O_3 and NH_3 impacts from Agrium's ambient standard demonstration is presented in Table 4. 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.

Table 4. Maximum Impacts Compared to the Ambient Standards

Pollutant	Avg. Period	Modeled Design Concentration (μg/m³)	Background Concentration (μg/m³)	Total Impact (μg/m³)	Ambient Standard (μg/m³)
NO_2	1-hour	168.0	*Included*	**168.0**	188
	Annual	14.42	2.6	**17.0**	100
PM-2.5	24-hour	6.03	12.0	**18.0**	35
	Annual	1.12	3.6	**4.72**	12
PM-10	24-hour	19.2	30.0	**49.2**	150
CO	1-hour	5,476.7	1,400	**6,877**	40,000
	8-hour	2,803.0	1,000	**3,803**	10,000
NH3	8-hour	197.8	0.35	**198**	2100

The maximum modeled NO_2, PM-2.5 and PM-10 increment impacts from Agrium's increment demonstration is presented in Table 5. The respective Class II increment is also presented for comparison. All of the impacts are less than the applicable Class II increment. Therefore, Agrium has demonstrated compliance with the maximum allowable increases.

Table 5. Maximum impacts compared to the increments

Pollutant	Avg. Period	Modeled Design Concentration (μg/m³)	Class II Increment (μg/m³)
NO_2	Annual	8.16	25
PM-2.5	24-hour	8.39	9
	Annual	1.51	4
PM-10	24-hour	21.7	30
	Annual	1.51	17

7. OZONE IMPACTS

As discussed in the *Background* section, O_3 is a triggered PSD-pollutant for this project (as well as VOC and NOx, emissions of which can form tropospheric O_3). Agrium was therefore required to demonstrate compliance with the O_3 AAAQS, per 40 CFR 52.21(k).

O_3 is not usually emitted directly into the air. It is instead created in the atmosphere through chemical reactions between NOx and VOC in the presence of sunlight. It is inherently a regional pollutant, the result of chemical reactions between emissions from many NOx and VOC sources over a period of hours or days, and over a large area.

The opening sentence of Section 5.3.2(a) of the Guideline states the O_3 assessment is dependent on "the magnitude of emissions." When warranted, the Guideline recommends a two-tiered approach for assessing the O_3 impacts from a stationary source. Tier 1 relies on "existing technical information," whereas Tier 2 relies on photochemical modeling. Tier 1 is the typical approach.

Agrium continued to use the same approach as in their 2014 analysis. In that analysis, Agrium demonstrated that KNO emissions would not cause or contribute to a violation of the O_3 AAAQS by comparing the PTE of its precursor pollutants to those from nearby stationary sources. They then extrapolated the monitored O_3 impacts proportional to the increase of regional precursor emissions due to the KNO project and compared that value to the AAAQS. Because the projected O_3 impacts were less than the AAAQS, the Department found that KNO would not cause or contribute to a violation of the O_3 AAAQS.

The percent increase in precursor potential emissions at KNO due to the current project remains small in comparison to the overall regional emissions. The Department updated the calculations performed in the 2014 analysis to reflect the increased PTE at KNO and found the potential increase in regional NOx emissions to be 6.2%. VOC emissions from KNO would also increase by 7.9%. Projecting potential O_3 impacts (using data collected at KNO during 2014-2015) assuming a 7.9% increase yields an estimated maximum concentration of 64.7 ppb, versus the AAAQS of 75 ppb. Therefore, the Department continues to find that the KNO project will not cause or contribute to a violation of the O_3 AAAQS.

8. ADDITIONAL IMPACT ANALYSES

PSD applicants must provide an analysis "*…of the impairment to visibility, soils and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification*" under 40 CFR 52.21(o). The focus is on potential impacts within the general area of the stationary source, rather than the Class I AQRV analyses which a FLM may request under 40 CFR 52.21(p). 40 CFR 52.21(o) also clarifies that the applicant "*need not provide an analyses of the impact on vegetation having no significant commercial or recreational value*." Agrium provided the additional impact analysis in Section 19 of their modeling report. The Department's findings regarding their additional impact analyses are reported below.

8.1. Associated Growth Analysis

As stated in the application for AQ0083CPT06, Agrium does not expect the KNO Restart Project to cause significant growth in the local commercial, residential, or industrial sector. The Department accepts KNO's assessment.

8.2. Visibility Impacts

PSD applicants must assess whether the emissions from their stationary source, including associated growth, will impair visibility. Agrium updated their previous visibility analysis using the current version of VISCREEN (version 13190) to estimate their worst-case plume blight. They used updated emissions rates for NOx and PM. Their approach was otherwise consistent with their 2014 analysis.

The VISCREEN results of their plume blight analysis exceeded 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. As previously discussed, the FLMs for Tuxedni and Denali did not request a visibility analysis.

8.3. Soil and Vegetation Impacts

The ambient demonstration provided by applicants is typically adequate for showing that their air emissions will not cause adverse visibility, soil, or vegetation impacts within the project area. Congress established "primary" NAAQS and "secondary" NAAQS in Section 109(b) of the CAA. The primary NAAQS protect public health, while the secondary NAAQS protect public welfare. Congress further stated in Section 302(h) of the CAA, "*All language referring to the effects of **welfare** includes, but is not limited to, effects on **soils**, water, crops, **vegetation**, manmade materials, animals, wildlife, weather, **visibility**…*" (emphasis added). The AAAQS and primary NAAQS are identical for each of the modeled pollutants. However, the annual PM-2.5 secondary NAAQS (15 µg/m^3) is less stringent than the annual PM-2.5 primary NAAQS/AAAQS (12 µg/m^3). Therefore, a modeling analysis that demonstrates compliance with the AAAQS also demonstrates compliance with the secondary NAAQS.

Agrium demonstrated that they can comply with the AAAQS. Therefore, their ambient analysis generally demonstrates that they will not have adverse visibility, soil, or vegetation impacts within the project area. The maximum cumulative impacts for the PSD-triggered pollutants with secondary NAAQS are reiterated in Table 6.

Table 6. Maximum Total Impacts Compared to the Secondary NAAQS

Pollutant	Avg. Period	Total Impact (µg/m^3)	Secondary NAAQS (µg/m^3)
NO_2	Annual	**17.0**	100
PM-2.5	24-hour	**18.1**	35
	Annual	**12.0**	15
PM-10	24-hour	**49.2**	150

9. CONCLUSIONS

The Department concludes the following based on its review of Agrium's permit application and ambient demonstrations:

1. Agrium's characterizations of the proposed exhaust stacks comply with the stack height and dispersion requirements described in 40 CFR 52.21(h) ***Stack Heights.***
2. Agrium's ambient demonstration satisfies the ***Source Impact Analysis*** requirements of 40 CFR 52.21(k). Agrium demonstrated that the NO_2, PM-10 and PM-2.5 emissions associated with operating the stationary source, within the restrictions listed in this report, will not cause or contribute to a violation of the following AAAQS: one-hour and NO_2, 24-hour PM-10, 24-hour and annual PM-2.5, one-hour and eight-hour CO, and eight-hour NH_3. They also demonstrated that the emissions will not cause or contribute to a violation of the following increments: NO_2, 24-hour and annual PM-10, and 24-hour and annual PM-2.5.
3. Agrium appropriately used the models and methods required under 40 CFR 52.21(l) ***Air Quality Models***.
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 pre-construction data and project impact analysis satisfies the ***Preapplication Analysis*** requirements of 40 CFR 52.21(m)(1).
6. Agrium provided the ***Additional Impact Analyses*** required under 40 CFR 52.21(o).

The Department developed permit conditions in Construction Permit AQ0083CPT07 to ensure Agrium complies with the AAAQS and Class II increments. These conditions are *summarized* as follows:

- To protect the NO_2, PM-10, and PM-2.5 AAAQS and increments, and the NH_3 and O_3 AAAQS:

  Stack Configuration
  - Construct and maintain vertical, uncapped exhaust stacks for all EUs listed in the permit except as noted below:
    - The scrubber (EU 41), the MDEA storage tanks (EUs 41B and 41C), the deaerator vent (EU 60), the well pump engine (EU 65), the fire pump engine (EU 66), and the urea storage warehouse baghouse (EUs 47C and 47D) may have horizontal releases; and
    - For all EUs, Agrium may use flapper rain covers, or other similar designs, that do not hinder the vertical momentum of the exhaust plume

Stack Heights

- o Construct and maintain exhaust stacks with release points above grade that equals or exceeds the minimum height listed in Table 1 for that EU.

Operating Restrictions

- o Comply with all BACT limits.

- To protect the Annual NO_2 and PM-2.5 AAAQS and increments, and the Annual PM-10 increment:

  Operating Restrictions

  - o Limit the hours of operation of the Solar Combustion Turbines (EUs 55a through 59a) in bypass mode to no more than 204 hours/year;
  - o Limit the hours of operation of the Startup Heater (EU 13) to no more than 200 hours/year; and
  - o Limit the hours of operation of the Well Pump Engine (EU 65) and Fire Pump Engine (EU 66) to no more than 168 hours per year, each.

- To protect the 1-hour NO2, 24-hour PM-10, and 24-hour PM-2.5 AAAQS and Increments; the 1-hour and 8-hour NH3 AAAQS; and the 8-hour O3 AAAQS:

  Operating Restrictions

  - o Operate no more than one of the Solar Combustion Turbines (EUs 55a through 59a) concurrently when in bypass mode;
  - o Limit the hours of operation of the Fire Pump Engine (EU 66) to no more than 4 hours per day;
  - o Limit the hours of operation of the Startup Heater (EU 13) to no more than 200 hours/year; and
  - o Limit the hours of operation of the Well Pump Engine (EU 65) and Fire Pump Engine (EU 66) to no more than 168 hours per year, each.