Message

From: Shawnee.Chen@deq.idaho.gov [Shawnee.Chen@deq.idaho.gov]
Sent: 11/28/2019 12:17:47 AM
To: Hardesty, Doug [Hardesty.Doug@epa.gov]
CC: Shawnee.Chen@deq.idaho.gov
Subject: FW: Proposed PTC for EPA review - REXBURG FACILITY OF BASIC AMERICAN FOODS, A DIVISION OF BASIC AMERICAN, INC. - P-2011.0132 PROJ 62264
Attachments: 62264 EPA Review Proposed Permit LTR.pdf; 62264 proposed permit for EPA review no track changes.pdf; 62264 proposed SOB for EPA review no track changes.pdf; App A of SOB - RX Flake expansion calculations workbook 191006 (AP-42 NG PM) w edits.pdf; App A2 of SOB direct fired amu calcs and volume source setup 191006 (AP-42 NG PM).pdf; Appendix B of SOB - BAXREX General Modeling Review Memorandumdraftv2.pdf; Appendix D -scrubber Pages from BAF Rexburg Expansion PTC App July 2019 update 7.11.2019.PDF; Appendix E of SOB - PTC Processing Fee Calculation Worksheet.XLS; 62264 Response to Comment.pdf

Importance: High

Hi Doug,

Sorry, I have just added "62264 Response to Comment" file; I missed it in the previous email.

Regards,
Shawnee

From: Shawnee Chen
Sent: Wednesday, November 27, 2019 5:09 PM
To: 'Hardesty, Doug'
Cc: Shawnee Chen
Subject: Proposed PTC for EPA review - REXBURG FACILITY OF BASIC AMERICAN FOODS, A DIVISION OF BASIC AMERICAN, INC. - P-2011.0132 PROJ 62264
Importance: High

Hi Doug,

This is a proposed PTC for a Tier I facility. DEQ received comments only from the facility during the public comment period. DEQ has addressed the comments in this proposed PTC.

Because the facility is under a very tight project schedule and also because the comments were from the facility only, DEQ is requesting an expedited 5-day review. Please let DEQ know if the permit issuance can be expedited.

Regards,
Shawnee

P.S., I am trying to reset my password to access EPA CDX for these files. Due to the facility's tight timeframe, I am using the email system too just in case.

Shawnee Chen, PE | Senior Air Quality Engineer
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Our mission is to protect human health and the quality of Idaho's air, land, and water.

Air Quality

PERMIT TO CONSTRUCT

Permittee	Rexburg Facility of Basic American Foods, a Division of Basic American, Inc.
Permit Number	P-2011.0132
Project ID	62264
Facility ID	065-00008
Facility Location	40 East 7th North Rexburg, ID 83440

Permit Authority

This permit (a) is issued according to the "Rules for the Control of Air Pollution in Idaho" (Rules), IDAPA 58.01.01.200–228; (b) pertains only to emissions of air contaminants regulated by the State of Idaho and to the sources specifically allowed to be constructed or modified by this permit; (c) has been granted on the basis of design information presented with the application; (d) does not affect the title of the premises upon which the equipment is to be located; (e) does not release the permittee from any liability for any loss due to damage to person or property caused by, resulting from, or arising out of the design, installation, maintenance, or operation of the proposed equipment; (f) does not release the permittee from compliance with other applicable federal, state, tribal, or local laws, regulations, or ordinances; and (g) in no manner implies or suggests that the Idaho Department of Environmental Quality (DEQ) or its officers, agents, or employees assume any liability, directly or indirectly, for any loss due to damage to person or property caused by, resulting from, or arising out of design, installation, maintenance, or operation of the proposed equipment. Changes in design, equipment, or operations may be considered a modification subject to DEQ review in accordance with IDAPA 58.01.01.200–228.

Date Issued Proposed for EPA Review

Shawnee Chen, PE, Permit Writer

Mike Simon, Stationary Source Manager

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1 Permit Scope

Purpose

1.1 This permitting action modifies PTC No. P-2011.0132 Project 62057, issued on May 11, 2018. It is for installing a new flake production line, two new boilers, a natural-gas fired belt dryer, and several air makeup units, for increasing Process A production, and for removing a boiler and a steam-heated belt dryer from Process B.

[PROPOSED]

1.2 Those permit conditions that have been revised by this permitting action are identified by the permit issue date citation located directly under the permit condition and on the right-hand margin.

1.3 This PTC terminates PTC No. P-2011.0132 project 62134, issued on May 17, 2019 and modifies and replaces PTC No. P-2011.0132 Project 62057, issued on May 11, 2018.

[PROPOSED]

Regulated Sources

1.4 Table 1.1 lists all sources of regulated emissions in this permit.

Table 1.1 Regulated Sources

Permit Section	Source ID	Source Descriptions	Emission Controls
		Boilers	
3	Kipper & Sons Boiler (also called the Kipper boiler)	Manufacturer: Kipper & Sons Model: N/A S/N: 1300 Heat input rating: 90.0 MMBtu/hr Maximum steam production rate: 65,000 lb/hr Permitted annual steam production rate: 189,800,000 lb/yr Fuel: wood Date installed: 1981	Multiclone and wet Scrubber in series
4	Boiler 1A	Manufacturer: Indeck Keystone Model: KD3.0068 Type D Heat input rating: 98 MMBtu/hr Maximum steam production rate: 80,600 lb/hr Fuel: natural gas only Date of construction: 2018	Low-NO_x burner
	Boiler 2A	Manufacturer: Indeck Keystone Model: KD3.0068 Type D Heat input rating: 98 MMBtu/hr Maximum steam production rate: 80,600 lb/hr Fuel: natural gas only Date of construction: 2018	Low-NO_x burner
	Boiler 2	Manufacturer: Murray Model: MCF3-43 S/N: 10509 Heat input rating: 49.9 MMBtu/hr Maximum steam production rate: 40,000 lb/hr Fuel: natural gas only Date installed: 2010	None
		Process A	
5	7020	Cooler/Dryer 7020 (Cooler vent)	None
	7101	Cooler/Dryer 7101 (Dryer, 6.5 MMBtu/hr, natural gas-fired)	None

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Permit Section	Source ID		Source Descriptions	Emission Controls
	7102		Cooler/Dryer 7102 (Dryer, 6.5 MMBtu/hr, natural gas-fired)	None
	7019		Cooler/Dryer 7019 (Dryer, 6.6 MMBtu/hr, steam and natural gas)	None
	7001		Cooler/Dryer 7001 (Dryer, steam-heated)	None
	7027		Cooler/Dryer 7027 (Cooler)	None
	7006		Material Recovery Unit 7006	None
Process B				
6	Proctor 4 Dryer		Proctor 4 Dryer, 2000 lb/hr, natural gas fired Stage A: 8.8 MMBtu/hr (Winnox 0200 burner) Stages BCD: 8.8 MMBtu/hr (Winnox 0200 burner) and 2.0 MMBtu/hr (Winnox 0100 burner)	Low-NO_x burners
	5034		Material Recovery Unit 5034	None
	5037		Cooler/Dryer 5037 (Cooler/dryer vent, dryer is steam heated)	None
	4000		Cooler/Dryer 4000 (Dryer, steam heated)	None
6	228		Cooler/Dryer 228 (Dryer, natural gas-fired, 16.1 MMBtu/hr)	None
	234		Cooler/Dryer 234 (Second exhaust from dryer 228)	None
	707		Material Recovery Unit 707 (fabric filter)	None
	725		Material Recovery Unit 725 (fabric filter)	None
	8		Material Recovery Unit 8 (fabric filter)	None
	5001		Material Recovery Unit 5001	None
	5000		Material Recovery Unit 5000 (fabric filter)	None
	432		Material Recovery Unit 432 (fabric filter)	None
	322		Material Recovery Unit 322	None
	572		Material Recovery Unit 572 (vent from material recovery cyclone in animal feed load-out system)	None
	33		Vegetable Dryer M33 (Dryer, natural gas-fired, 2.7 MMBtu/hr)	None
	44		Vegetable Dryer M44 (Dryer, natural gas-fired, 2.75 MMBtu/hr)	None
	56		Vegetable Dryer M56 (Dryer, natural gas-fired, 1.6 MMBtu/hr)	None
	62		Vegetable Dryer M62 (Dryer, natural gas-fired, 1.6 MMBtu/hr)	None
	86		Vegetable Dryer M86 (Dryer, steam heated)	None
	Flk-N	Flake Drum #1	Manufacturer: Idaho Steel Products Model: 8FT X 21FT DRUM Installed date: 2018 Dryer, steam-heated, 3,000 lb/hr	MicroMist Scrubber System Manufacturer: EnviroCare International Model No.: MicroMist $PM_{10}/PM_{2.5}$ removal efficiency: 75%
		Flake Drum #2	Identical with Flake Drum #1	
	Flk-S	Flake Drum #3	Identical with Flake Drum #1	MicroMist Scrubber System Manufacturer: EnviroCare International Model No.: MicroMist $PM_{10}/PM_{2.5}$ removal efficiency: 75%
		Flake Drum #4	Identical with Flake Drum #1	
7	Flake North Air Makeup Unit (AMU) #1		Flake Air Makeup Unit #1, 4.86MMBtu/hr	Low-NO_x burner
	Flake North AMU #2		Flake Air Makeup Unit #2, 4.86 MMBtu/hr	Low-NO_x burner
	Flake South AMU#3		Flake Wet Process Air Makeup Unit #3, 2.86 MMBtu/hr	Low-NO_x burner
	SLAB AMU#4		SLAB Air Makeup Unit #4, 1.29 MMBtu/hr	Low-NO_x burner
	Potato Cleaning AMU#5		Potato Cleaning Air Makeup Unit #5, 0.72 MMBtu/hr	Low-NO_x burner

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Permit Section	Source ID	Source Descriptions	Emission Controls
	Boiler Room North AMU#6	Boiler Room Air Makeup Unit #6, 2.5 MMBtu/hr	Low-NO_x burner
	Boiler Room South AMU#7	Boiler Room Air Makeup Unit #7, 2.5 MMBtu/hr	Low-NO_x burner
	NA	Plant Space Heaters (27.8 MMBtu/hr)	None
	RX-OBI1	Reyco Unit (13.3 MMBtu/hr), installed in 2014	None

[PROPOSED]

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2 Facility-Wide Conditions

2.1 Facility-Wide Requirements

Reserved (The Tier I operating permit contains facility-wide conditions that apply to this facility.)

2.2 Performance Testing

If performance testing is required, the following test methods shall be used unless otherwise specified in this permit or approved by DEQ in accordance with IDAPA 58.01.01.157.02:

Table 2.1 Test Methods

Pollutant	Test Method	Additional Requirements
$PM_{2.5}$ and PM_{10}	EPA Methods 5 / 202, or 201A / 202	Particulate matter with an aerodynamic diameter less than or equal to a 2.5 and 10 micrometers (respectively), including condensable particulate as defined in IDAPA 58.01.01.006.
NO_x	EPA Method 7E	---
CO	EPA Method 10	---

[PROPOSED]

ED_013256A_00004256-00006

3 Kipper Boiler

3.1 Process Description

The Kipper boiler is a wood and coal-fired boiler with an original steam production rating of 60,000 pounds per hour. The boiler can burn up to 39% coal on a fuel weight basis (i.e. 50% of the heating value). The Kipper boiler was installed in 1981, and an economizer was added in 2001, increasing the maximum steam production rate to 65,000 lb/hr due to increased boiler efficiency. Emission controls on the Kipper boiler include a Zurn multiclone dust collector and a Riley Ventri-Rod® scrubber in series.

The permittee has requested to eliminate the option of burning coal, and therefore the use of coal as a fuel to Kipper boiler shall be made inoperative. In addition, the permittee has also requested that the Kipper boiler is used as a backup or standby boiler with an annual steam production limit of 189,800,000 pound per year and that the Kipper boiler will not operate concurrently with Boiler 2.

[PROPOSED]

3.2 Control Device Descriptions

Table 3.1 Emissions Unit and Emissions Control Device

Emissions Units / Processes	Control Devices
Kipper Boiler	Zurn multiclone and Riley Ventri-Rod® scrubber in series

Emission Limits

3.3 Emissions Limits

The emissions from the Kipper boiler stack shall not exceed any corresponding emissions rate limits listed in Table 3.2.

Table 3.2 Kipper Boiler Emission Limits [a]

$PM_{2.5}/PM_{10}$ [b]		NO_X	
lb/hr [c]	T/yr [d]	lb/hr [c]	T/yr [d]
13.6	19.8	21.6	31.5

a In absence of any other credible evidence, compliance is ensured by complying with permit operating, monitoring, and record keeping requirements.

b Particulate matter with an aerodynamic diameter less than or equal to a nominal ten (10) micrometers, including condensable particulate as defined in IDAPA 58.01.01.006. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers, including condensable particulate as defined in IDAPA 58.01.01.006.

c Pounds per hour, as determined by a test method prescribed by IDAPA 58.01.01.157, EPA reference test method, continuous emission monitoring system (CEMS) data, or DEQ-approved alternative.

d Tons per any consecutive 12-calendar month period.

[PROPOSED]

3.4 Reserved

3.5 Fuel Burning Equipment - PM

Particulate matter emissions from the Kipper boiler shall not exceed 0.080 gr/dscf corrected to 8% oxygen when burning wood fuel.

[PROPOSED]

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Operating Requirements

3.6 Kipper Boiler Fuel Type

The permittee shall exclusively combust wood in the Kipper boiler.

[PROPOSED]

3.7 Decommission Coal as Fuel

Equipment to use coal as a fuel to Kipper boiler shall be inoperative no later than 60 days after the permit issuance. The permittee shall notice DEQ Idaho Falls Regional office after this is achieved.

[PROPOSED]

3.8 Steam Production

- The Kipper boiler steam production rate shall not exceed 65,000 pounds of steam per hour on a 24-hour rolling average.
- The Kipper boiler steam production rate shall not exceed 189,800,000 pounds of steam per any consecutive 12-month period.

[PROPOSED]

3.9 Ventri-Rod® Scrubber and Multiclone

The permittee shall install, maintain, and operate a multiclone and a wet scrubber on the Kipper boiler to control the emissions of PM, PM_{10} and $PM_{2.5}$.

[PROPOSED]

3.10 Operation Requirement

The Kipper boiler shall not operate concurrently with Boiler 2.

[PROPOSED]

3.11 Boiler, Ventri-Rod® Scrubber, and Multiclone Annual Inspection and Maintenance

At least once per calendar year, the permittee shall inspect the internal workings of the Kipper boiler and perform any maintenance required to maintain efficient combustion. The permittee shall also inspect the Ventri-Rod® scrubber and multiclone and perform any maintenance required. The permittee shall maintain records of the boiler, Ventri-Rod® scrubber, and multiclone maintenance conducted to comply with this permit condition. The records shall provide the date the inspection was conducted and a description of the maintenance performed on the boiler to maintain combustion efficiency.

[5/11/18]

3.12-3.13 40 CFR 63 Subpart JJJJJJ Operating Requirements

Reserved (The Tier I operating permit contains federally-applicable NESHAP Subpart JJJJJJ operating requirements that apply to this facility.)

[5/11/18]

3.14 Fuel Requirement

Wood materials combusted in the Kipper Boiler shall be either "clean cellulosic biomass" (as defined in 40 CFR 241.2) or fuels produced from the processing of discarded non-hazardous secondary materials and that meet the legitimacy criteria specified in 40 CFR 241.3(d)(1). If wood materials that do not meet these requirements are combusted in the Kipper boiler, the permittee shall comply with applicable provisions for units combusting non-hazardous solid waste enacted in accordance with 40 CFR 60, Subpart DDDDD.

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Monitoring and Recordkeeping Requirements

3.15 Steam Monitoring

- The steam produced in the boiler shall be monitored and recorded at least once per hour in units of pounds of steam per hour and average pounds of steam per hour per rolling 24-hour period.
- Every month, the permittee shall record the steam produced in the month and record the steam produced in the previous consecutive 12-month period.

[PROPOSED]

3.16 Operation Requirement Monitoring

The permittee shall keep records, such as Kipper boiler and Boiler 2 steaming production records containing date and time to demonstrate that the Kipper boiler does not operate concurrently with Boiler 2.

[PROPOSED]

3.17-3.26 CAM 40 CFR 64 Monitoring and Recordkeeping Requirements

Reserved (The Tier I operating permit contains federally-applicable NESHAP Subpart JJJJJJ monitoring and recordkeeping requirements that apply to this facility.)

[5/11/18]

3.27 NESHAP 40 CFR 63 Subpart JJJJJJ Monitoring and Recordkeeping Requirements

Reserved (The Tier I operating permit contains federally-applicable NESHAP Subpart JJJJJJ monitoring and recordkeeping requirements that apply to this facility.)

[5/11/18]

Performance Testing Requirements

3.28 NOx and CO Performance Test

Within five years of the permit issuance and at such other times as may be required by the Director, the permittee shall conduct a performance test to measure NOx and CO emissions from the Kipper boiler stack to demonstrate compliance with the NOx limits in Emissions Limits permit condition and to verify CO emissions factor (EF) that is equal to or less than 0.669 lb/MMBtu, or 0.927 lb CO/1,000 lbs steam, whichever is more stringent. The test shall be conducted in accordance with the procedures outlined in Performance Test permit condition (i.e., Permit Condition 2.2). The performance test and any subsequent performance tests conducted to demonstrate compliance shall be performed in accordance with IDAPA 58.01.01.157. In addition, the following information shall be recorded during each performance test run and included in the performance test report:

- The boiler steaming rate;
- The boiler shall be operated at the worst case normal production rate during the performance test. A description of how this requirement was met shall be included in the performance test report;
- The measured NOx and CO emission rates shall be reported in units of pounds per hour. All calculations used to convert the test results into these units shall be provided in the test report; and

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- The quantity of wood shall be reported by weight (in units of tons/hr) or by gross heat content (in units of MMBtu/hr and Btu/lb). The methods used to obtain these values and to make these determinations shall be described.

3.29 PM and PM_{10} Performance Tests

Within 10 years of the permit issuance and at such other times as may be required by the Director, the permittee shall conduct a performance test to measure PM and PM_{10} emissions from the Kipper boiler stack to demonstrate compliance with the PM emissions standard in the Fuel Burning Equipment – PM permit condition and the $PM_{10}/PM_{2.5}$ emissions limits in Emissions Limits permit condition.

The tests shall be conducted in accordance with the procedures outlined in Performance Test permit condition (i.e., Permit Condition 2.2). The performance tests conducted to demonstrate compliance shall be performed in accordance with IDAPA 58.01.01.157. In addition, the following information shall be recorded during each performance test run and included in the performance test report:

- The boiler steaming rate;
- The static air pressure and water pressure at the wet Ventri-Rod® scrubber;
- The pressure drop across the multiclone;
- The quantity of wood shall be reported, either by weight (in units of tons/hr) or by gross heat content (in units of MMBtu/hr and Btu/lb). The methods used to obtain these values shall be described.

The boiler shall be operated at the worst case normal production rate during the performance test. A description of how this requirement was met shall be included in the performance test report. Visible emissions shall be observed and recorded using the methods specified in IDAPA 58.01.01.625. In addition to correcting the Method 5 test results to 8% oxygen, the Method 5 results shall be corrected for altitude as required by IDAPA 58.01.01.680 to demonstrate compliance with the fuel burning equipment particulate matter standard.

[PROPOSED]

Reporting Requirements

3.30 Reserved

3.31 CAM 40 CFR 64 Reporting Requirements

Reserved (The Tier I operating permit contains federally-applicable CAM monitoring and recordkeeping requirements that apply to this facility.)

[5/11/18]

3.32 NESHAP 40 CFR 63, Subpart JJJJJJ Reporting Requirements

Reserved (The Tier I operating permit contains federally-applicable NESHAP Subpart JJJJJJ reporting requirements that apply to this facility.)

[5/11/18]

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4 Boiler 2, Boiler 1A, and Boiler 2A

4.1 Process Description

Steam is produced in the boilers to run drying processes in Process A and Process B. Boiler 1A and Boiler 2A are the primary boilers, with Boiler 2 and Kipper Boiler providing backup or standby capacity. Boiler 2 will not operate concurrently with the Kipper boiler.

Table 4.1 describes the devices used to control emissions from Boiler 1A, Boiler 2A, and Boiler 2.

[PROPOSED]

4.2 Control Device Descriptions

Table 4.1 Boilers Description

Emissions Units / Processes	Control Devices
Boiler 1A	Low-NO_x burner
Boiler 2A	Low-NO_x burner
Boiler 2	None

[PROPOSED]

Emission Limits

4.3 Emission Limits

Emissions from each boiler stack shall not exceed any corresponding emission rate limit in the following table.

Table 4.2 Emission Limits [a]

Source Description		$PM_{2.5}$ [b]	PM_{10} [c]	NO_x
		lb/hr [d]	lb/hr [d]	lb/hr [d]
Boiler 1A Stack	Boiler 1A	0.73	0.73	1.79
	Emissions from AMUs allocated to Boiler 1A stack	0.001	0.001	0.103
Boiler 2A Stack	Boiler 2A	0.73	0.73	1.79
	Emissions from AMUs allocated to Boiler 2A stack	0.001	0.001	0.103
Boiler 2 Stack	Boiler 2	0.37	0.37	4.89

a) In absence of any other credible evidence, compliance is assured by complying with permit operating, monitoring, and record keeping requirements.
b) Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers, including condensable particulate as defined in IDAPA 58.01.01.006.
c) Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers, including condensable particulate as defined in IDAPA 58.01.01.006.
d) Pounds per hour, as determined by a test method prescribed by IDAPA 58.01.01.157, EPA reference test method, continuous emission monitoring system (CEMS) data, or DEQ-approved alternative.
e) Tons per any consecutive 12-month period.

[PROPOSED]

4.4 Fuel Burning Equipment - PM

Particulate matter emissions from each boiler stack (Boiler 2, Boiler 1A, and Boiler 2A) shall not exceed 0.015 gr/dscf corrected to 3% oxygen when burning natural gas, in accordance with IDAPA 58.01.01.676-677.

[PROPOSED]

4.5 Boiler Annual Inspection and Maintenance

At least once per calendar year or per a DEQ-approved schedule, the permittee shall tune and adjust the burner systems of Boiler 2, Boiler 1A, and Boiler 2A to maintain efficient combustion.

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The permittee shall maintain records of the boiler tuning conducted to comply with this permit condition. The records shall provide the date the tuning was conducted and a description of the adjustments made to the boiler to maintain combustion efficiency.

[PROPOSED]

4.6 Natural Gas Combustion Monitoring

The permittee shall install, calibrate, maintain, and operate equipment to measure the quantity of natural gas combusted in Boiler 2, Boiler 1A, and Boiler 2A. The natural gas combustion data is used in the facility-wide CO emission calculation in the monitoring and recordkeeping requirements of the CO Facility-Wide Emissions Limit section (Section 8). The following quantities of natural gas combusted shall be monitored and recorded each calendar month in units of million standard cubic feet (MMscf) per month and MMscf per rolling 12-calendar month period:

- Total gas combusted at the Rexburg facility
- Total gas combusted by Boilers 1A and 2A (G_{B1A2A})

[PROPOSED]

- Gas combusted by Boiler 2 (G_{B2})

[PROPOSED]

- Each rolling 12-calendar month calculation shall be the summation of the quantities of gas combusted in that calendar month and in each of the preceding 11 calendar months.

Performance Testing Requirements

4.7 Initial Performance Test

Within 180 days after initial startup, the permittee shall conduct performance tests to measure NO_x emissions from either Boiler 1A or Boiler 2A to demonstrate compliance with the corresponding boiler pound per hour emission rate limit (Permit Condition 4.3). Tests shall be conducted in accordance with the procedures outlined in the performance testing requirements (Permit Conditions 2.2 and 4.8 and General Provisions 9.7 through 9.9) or as otherwise approved by DEQ. The performance test monitoring parameters (Permit Condition 4.8) shall be recorded during each performance test run and included in the performance test report. The boiler shall be operated at the worst-case normal production rate during the performance test. A description of how this requirement was met shall be included in the performance test report.

[PROPOSED]

4.8 Performance Test Monitoring

The permittee shall monitor and record the following parameters during each performance test:

- The steaming rate in pounds of steam per hour (lb/hr) every 15 minutes.

[PROPOSED]

Monitoring, Recordkeeping, and Reporting Requirements

4.9-4.10 NSPS 40 CFR 60 Monitoring, Recordkeeping, and Reporting Requirements

Reserved (The Tier I operating permit contains federally-applicable NSPS Subpart Dc monitoring, recordkeeping, and reporting requirements that apply to this facility.)

[5/11/18]

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5 Process A (Drying Process and Material Transfer Systems)

5.1 Process Description

The Basic American Foods Rexburg facility produces a variety of dehydrated food products for external customers and for internal use. Products include potato granules, formulated dehydrated food products, dehydrated whole and piece food products, and animal feed. Raw materials into the process are cooked potatoes, cooked foods, dehydrated foods, and additives, including sulfites. The processes addressed by this section are listed in Table 5.1 and include coolers, dryers, dehydration lines, and material transfer systems. Emissions of PM from each of these sources are uncontrolled. Material Recovery Units (MRUs), in the form of cyclones and fabric filters, are integral process equipment used to separate the pneumatically conveyed product from the air stream. Drying heat is provided by both natural gas combustion and steam produced by the plant boilers. Process A was constructed in the early 1960's. This permitting action increases production limits of Process A from 61 T/day to 65 T/day.

[PROPOSED]

5.2 Control Device Descriptions

Table 5.1 Process A Description

Emissions Units / Processes	Control Devices	Emission Points
Cooler/Dryer 7020 (Cooler vent)	None	7020
Cooler/Dryer 7101 (Dryer, 6.5 MMBtu/hr, natural gas-fired)	None	7101
Cooler/Dryer 7102 (Dryer, 6.5 MMBtu/hr, natural gas-fired)	None	7102
Cooler/Dryer 7019 (Dryer, 6.6 MMBtu/hr, steam and natural gas)	None	7019
Cooler/Dryer 7001 (Dryer, steam-heated)	None	7001
Cooler/Dryer 7027 (Cooler)	None	7027
Material Recovery Unit 7006	None	7006

Emission Limits

5.3 Emission Limits

Emissions from the drying process and material transfer system stacks shall not exceed any corresponding emissions rate limits listed in the following table.

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Table 5.2 Dryer Process and Material Transfer System PM_{10} Emissions Limits

Source Description		$PM_{2.5}$ [b]	PM_{10} [c]	NO_x
		lb/hr [d]	lb/hr [d]	lb/hr [d]
Cooler/Dryer stack 7101	Cooler/Dryer 7101	2.345	2.345	0.332
	Emissions from AMUs allocated to Cooler/Dryer 7101 stack	0.019	0.019	0.156
Cooler/Dryer stack 7102	Cooler/Dryer 7102	2.345	2.345	0.332
	Emissions from AMUs allocated to Cooler/Dryer 7102 stack	0.018	0.018	0.155
Cooler/Dryer stack 7019	Cooler/Dryer 7019	0.894	0.894	0.337
	Emissions from AMUs allocated to Cooler/Dryer 7019	0.013	0.013	0.113

a) In absence of any other credible evidence, compliance is assured by complying with permit operating, monitoring, and record keeping requirements.
b) Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers, including condensable particulate as defined in IDAPA 58.01.01.006.
c) Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers, including condensable particulate as defined in IDAPA 58.01.01.006.
d) Pounds per hour, as determined by a test method prescribed by IDAPA 58.01.01.157, EPA reference test method, continuous emission monitoring system (CEMS) data, or DEQ-approved alternative.

[PROPOSED]

Operating Requirements

5.4 Production Limits

The production of dried products, including additives, from Process A shall not exceed 65 tons per 24-hour work day.

[PROPOSED]

5.5 Dryer Fuels

Each dryer shall combust only natural gas or be heated by steam from the plant boilers.

5.6 Process Identification

Process line A shall be identified by one or more signs posted on or near the process line. Each cooler or dryer shall also be identified in a manner that will allow an inspector to identify the equipment that corresponds to the equipment listed in the Process A Description table (Table 5.1).

Monitoring, Recordkeeping, and Reporting Requirements

5.7 Production Monitoring

The permittee shall monitor and record, on a daily basis, the calendar date and the total product output of dried food products (known as "Production from New Inputs"), in tons per day, from Process A. Daily production records may be maintained on a work-day basis, in which a work day commences at a specific time of day.

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6 Process B (Drying Process and Material Transfer Systems)

6.1 Process Description

The Basic American Foods Rexburg facility produces a variety of dehydrated food products for external customers and for internal use. Products include potato granules, formulated dehydrated food products, dehydrated whole and piece food products, and animal feed. Raw materials into the process are cooked potatoes, cooked foods, dehydrated foods, and additives, including sulfites. The processes addressed by this section are listed in Table 6.1 and include coolers, dryers, dehydration lines, and material transfer systems. Emissions of PM from each of these sources are uncontrolled. Material Recovery Units (MRUs), in the form of cyclones and fabric filters, are integral process equipment used to separate the pneumatically conveyed product from the air stream. Drying heat is provided by both natural gas combustion and steam produced by the plant boilers.

6.2 Control Device Descriptions

Table 6.1 Process B Description

Emissions Units / Processes		Control Devices	Emission Points
Material Recovery Unit 5034		None	5034
Cooler/Dryer 5037 (Cooler/dryer vent, dryer is steam heated)		None	5037
Cooler/Dryer 4000 (Dryer, steam heated)		None	4000
Cooler/Dryer 234/228 (Dryer, natural gas-fired, 16.1 MMBtu/hr)		None	234/228
Material Recovery Unit 707 (fabric filter)		None	707
Material Recovery Unit 725 (fabric filter)		None	725
Material Recovery Unit 8 (fabric filter)		None	8
Material Recovery Unit 5001		None	5001
Material Recovery Unit 5000 (fabric filter)		None	5000
Material Recovery Unit 432 (fabric filter)		None	432
Material Recovery Unit 322		None	322
Material Recovery Unit 572 (Vent from material recovery cyclone in animal feed load-out system)		None	572
Vegetable Dryer M33 (Dryer, natural gas-fired, 2.7 MMBtu/hr)		None	33
Vegetable Dryer M44 (Dryer, natural gas-fired, 2.75 MMBtu/hr)		None	44
Vegetable Dryer M56 (Dryer, natural gas-fired, 1.6 MMBtu/hr)		None	56
Vegetable Dryer M62 (Dryer, natural gas-fired, 1.6 MMBtu/hr)		None	62
Vegetable Dryer M86 (Dryer, steam heated)		None	86
Flake North (flake drum dryers #1 and #2)		A MicroMist Scrubber System	FLK_N
Flake South (flake drum dryers #3 and #4)		A MicroMist Scrubber System	FLK_S
Proctor 4 Belt Dryer	Stage A	Low-NO_x burners	P4A
	Stages B, C, D		P4BCD

[PROPOSED]

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Emission Limits

6.3 Emission Limits

Emissions from the drying process and material transfer system stacks shall not exceed any corresponding emissions rate limits listed in the following table.

Table 6.2 Dryer Process and Material Transfer System Emissions Limits [a]

Source Description			$PM_{2.5}/PM_{10}$ lb/hr [b]	NO_x lb/hr [b]
Flake North MicroMist Scrubber System scrubber stack		Flake North (Flake Drum #1 and Flake Drum #2)	0.453	0.00
		Emissions from AMUs allocated to the scrubber stack	0.033	0.271
Flake South MicroMist Scrubber System scrubber stack		Flake South (Flake Drum #3 and Flake Drum #4)	0.453	0.00
		Emissions from AMUs allocated to the scrubber stack	0.033	0.271
Proctor 4 Belt Dryer	Stage A stack	Proctor 4 Belt Dryer Stage A	0.415	0.267
		Emissions from AMUs allocated to Stage A stack	0.013	0.111
	Stages BCD stack	Proctor 4 Belt Dryer Stages B, C, D	1.726	0.267
		Emissions from AMUs allocated to Stages BCD stack	0.013	0.111
Cooler/Dryer 4000 (Dryer, steam heated) exhaust		Cooler/Dryer 4000	1.720	0.00
		Emissions from AMUs allocated to Cooler/Dryer 4000 exhaust	0.019	0.164
Cooler/Dryer 228 exhaust		Cooler/Dryer 228	1.100	0.480
		Emissions from AMUs allocated to Cooler/Dryer 228 exhaust	0.011	0.096
Cooler/Dryer 234 exhaust (Second exhaust from dryer 228)		Cooler/Dryer 234	0.310	0.320
		Emissions from AMUs allocated to Cooler/Dryer 234 exhaust	0.017	0.143
Stack group 33,44, 56, 62, and 86		Stack group 33,44, 56, 62, and 86	0.860	0.260
		Emissions from AMUs allocated to stack group 33,44, 56, 62, and 86	0.043	0.121

a In absence of any other credible evidence, compliance is ensured by complying with permit operating, monitoring, and record keeping requirements.

b Pounds per hour, as determined by a test method prescribed by IDAPA 58.01.01.157, EPA reference test method, continuous emission monitoring system (CEMS) data, or DEQ-approved alternative.

[PROPOSED]

Operating Requirements

6.4 Production Limits

The total production of dried products, including additives, from Process B shall not exceed 448 tons per 24-hour work day, including flake products. The flake line production shall not exceed 144 tons per 24-hour work day.

[PROPOSED]

6.5 Dryer Fuels

Each dryer shall combust only natural gas or be heated by steam from the plant boilers.

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6.6 Process Identification

Process line B shall be identified by one or more signs posted on or near the process line. Each cooler or dryer shall also be identified in a manner that will allow an inspector to identify the equipment that corresponds to the equipment listed in the Process B Description table (Table 6.1).

6.7 MicroMist Scrubber System

The permittee shall install and operate two MicroMist scrubber systems each with 75% or more removal efficiency for all particulates, including PM_{10} and $PM_{2.5}$.

Each of the two MicroMist scrubber systems shall treat the exhaust from two steam-heated flake drum dryers of the four steam-heated drum dryers as described in Table 6.1.

[PROPOSED]

6.8 MicroMist Scrubber System Operating Parameters

Each scrubber's operating parameter shall be equal to or greater than the value obtained during the most recent performance test demonstrating compliance with the emissions limits. Until an initial performance test demonstrating compliance with emissions limits is completed, each scrubber's operating parameter shall be equal to or greater than the respective values specified in the following:

- The liquid flow rate to the spray lances at quench stage shall be equal to or greater than 315 gallons per minute (gpm).
- The pressure drop across the MicroMist Venturi (MMV) stage shall be maintained between 17 to 25 inches of water (iwg).
- The inlet liquid flow rate to MMV stage shall be equal to or greater than 328 gpm.

The permittee shall install and operate the monitoring devices to measure the above parameters.

[PROPOSED]

Monitoring, Recordkeeping, and Reporting Requirements

6.9 Production Monitoring

The permittee shall monitor and record, on a daily basis, the calendar date and the total product output of dried food products including additives (known as "Production from New Inputs"), in tons per day, from Process B. Daily production records may be maintained on a work-day basis, in which a work day commences at a specific time of day.

6.10 MicroMist Scrubber System Operating Parameters Monitoring

The permittee shall monitor and record the following operating parameters for each MicroMist scrubber system once each week:

- The liquid flow rate to the spray lances at quench stage in gpm
- The pressure drop across the MicroMist Venturi (MMV) stage in inches of water.
- The inlet liquid flow rate to MMV stage in gpm.

[PROPOSED]

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Performance Testing Requirements

6.11 Initial Performance Test for PM_{10}

Proctor 4 belt dryer

Within 180 days after initial startup of Proctor 4 belt dryer, the permittee shall conduct performance tests to measure PM_{10} emissions from Proctor 4 belt dryer's two stacks to demonstrate compliance with the PM_{10} emission limits for the two stacks and to verify the emissions factors used in the emissions inventories (EI) calculation for Proctor 4 belt dryer.

MicroMist scrubber system scrubber stack

Within 180 days after initial startup of flake production, the permittee shall conduct performance tests to measure PM_{10} emissions from one MicroMist scrubber system scrubber stack (either Flake North or Flake South) to demonstrate compliance with the PM_{10} emission limit for the scrubber stack and to verify the emissions factor used in the emissions inventories (EI) calculation for the flake drum dryers.

Tests shall be conducted in accordance with the procedures outlined in the performance testing requirements (Permit Conditions 2.2 and 6.12, and General Provisions 9.7 through 9.9) or as otherwise approved by DEQ. The performance test monitoring parameters (Permit Condition 6.12) shall be recorded during each performance test run and included in the performance test report. The flake drum and dryer shall be operated at the worst-case normal production rate during the performance tests. A description of how this requirement was met shall be included in the performance test report.

[PROPOSED]

6.12 Performance Test Monitoring

The permittee shall monitor and record the following parameters during each performance test:

- The production rate(s) from the specific Process B emissions unit(s) (i.e., flake drum dryers, or Proctor 4 belt dryer) tested in tons of product per hour (T/hr) during each test run.
- The liquid flow rate to the spray lances at quench stage in gpm during the flake drum dryer test. The liquid flow rate shall be monitored and recorded at least once every 15 minutes of sampling time.
- The pressure drop across the MicroMist Venturi (MMV) stage in iwg during the flake drum dryer test. The pressure drop shall be monitored and recorded at least once every 15 minutes of sampling time.
- The inlet liquid flow rate to MMV stage in gpm during the flake drum dryer test. The liquid flow rate shall be monitored and recorded at least once every 15 minutes of sampling time.

[PROPOSED]

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7 Plant Space Heaters

7.1 Process Description

The BAF Rexburg Facility has numerous existing space heaters ranging in size from less than 100,000 Btu/hr to 8.8 MMBtu/hr, with a total combustion capacity of 30.8 MMBtu/hr. Most of the units provide direct heating; i.e., the combustion air from the unit is discharged directly into the room to provide heating. In addition, in 2014 BAF installed Reyco unit (RX-OBI1), a natural-gas fired space heater rated at 13.3 MMBtu/hr. New air makeup units at a total rate of 19.6 MMBtu/hr are proposed to be installed for this project.

[PROPOSED]

Emission Limits

7.2 Emission Limits

Space heaters emissions are allocated to the process stacks used for modeling analysis. Emissions from plant space heaters are regulated in Table 5.2 and Table 6.2 of the permit and by Permit Condition 8.1.

[PROPOSED]

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8 Facility-Wide CO Emission Limit

8.1 Facility-Wide CO PTE Calculation and Notification

Whenever a new source is installed that emits CO, the permittee shall calculate facility-wide CO PTE and submit the revised facility-wide CO PTE to DEQ no later than 60 days of the installation, or within DEQ approved alternative timeframe.

The submittal shall be titled "Facility-wide CO PTE Change Notification for Rexburg Facility of Basic American Foods, a Division of Basic American, Inc. 065-00008"

[PROPOSED]

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9 General Provisions

General Compliance

9.1 The permittee has a continuing duty to comply with all terms and conditions of this permit. All emissions authorized herein shall be consistent with the terms and conditions of this permit and the "Rules for the Control of Air Pollution in Idaho." The emissions of any pollutant in excess of the limitations specified herein, or noncompliance with any other condition or limitation contained in this permit, shall constitute a violation of this permit, the "Rules for the Control of Air Pollution in Idaho," and the Environmental Protection and Health Act (Idaho Code §39-101, et seq.)

[Idaho Code §39-101, et seq.]

9.2 The permittee shall at all times (except as provided in the "Rules for the Control of Air Pollution in Idaho") maintain in good working order and operate as efficiently as practicable all treatment or control facilities or systems installed or used to achieve compliance with the terms and conditions of this permit and other applicable Idaho laws for the control of air pollution.

[IDAPA 58.01.01.211, 5/1/94]

9.3 Nothing in this permit is intended to relieve or exempt the permittee from the responsibility to comply with all applicable local, state, or federal statutes, rules, and regulations.

[IDAPA 58.01.01.212.01, 5/1/94]

Inspection and Entry

9.4 Upon presentation of credentials, the permittee shall allow DEQ or an authorized representative of DEQ to do the following:

- Enter upon the permittee's premises where an emissions source is located, emissions-related activity is conducted, or where records are kept under conditions of this permit;
- Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;
- Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
- As authorized by the Idaho Environmental Protection and Health Act, sample or monitor, at reasonable times, substances or parameters for the purpose of determining or ensuring compliance with this permit or applicable requirements.

[Idaho Code §39-108]

Construction and Operation Notification

9.5 This permit shall expire if construction has not begun within two years of its issue date, or if construction is suspended for one year.

[IDAPA 58.01.01.211.02, 5/1/94]

9.6 The permittee shall furnish DEQ written notifications as follows:

- A notification of the date of initiation of construction, within five working days after occurrence; except in the case where pre-permit construction approval has been granted then notification shall be made within five working days after occurrence or within five working days after permit issuance whichever is later;

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- A notification of the date of any suspension of construction, if such suspension lasts for one year or more;
- A notification of the anticipated date of initial start-up of the stationary source or facility not more than sixty days or less than thirty days prior to such date; and
- A notification of the actual date of initial start-up of the stationary source or facility within fifteen days after such date; and
- A notification of the initial date of achieving the maximum production rate, within five working days after occurrence - production rate and date.

[IDAPA 58.01.01.211.03, 5/1/94]

Performance Testing

9.7 If performance testing (air emissions source test) is required by this permit, the permittee shall provide notice of intent to test to DEQ at least 15 days prior to the scheduled test date or shorter time period as approved by DEQ. DEQ may, at its option, have an observer present at any emissions tests conducted on a source. DEQ requests that such testing not be performed on weekends or state holidays.

9.8 All performance testing shall be conducted in accordance with the procedures in IDAPA 58.01.01.157. Without prior DEQ approval, any alternative testing is conducted solely at the permittee's risk. If the permittee fails to obtain prior written approval by DEQ for any testing deviations, DEQ may determine that the testing does not satisfy the testing requirements. Therefore, at least 30 days prior to conducting any performance test, the permittee is encouraged to submit a performance test protocol to DEQ for approval. The written protocol shall include a description of the test method(s) to be used, an explanation of any or unusual circumstances regarding the proposed test, and the proposed test schedule for conducting and reporting the test.

9.9 Within 60 days following the date in which a performance test required by this permit is concluded, the permittee shall submit to DEQ a performance test report. The written report shall include a description of the process, identification of the test method(s) used, equipment used, all process operating data collected during the test period, and test results, as well as raw test data and associated documentation, including any approved test protocol.

[IDAPA 58.01.01.157, 4/5/00 and 4/11/15]

Monitoring and Recordkeeping

9.10 The permittee shall maintain sufficient records to ensure compliance with all of the terms and conditions of this permit. Monitoring records shall include, but not be limited to, the following: (a) the date, place, and times of sampling or measurements; (b) the date analyses were performed; (c) the company or entity that performed the analyses; (d) the analytical techniques or methods used; (e) the results of such analyses; and (f) the operating conditions existing at the time of sampling or measurement. All monitoring records and support information shall be retained for a period of at least five years from the date of the monitoring sample, measurement, report, or application. Supporting information includes, but is not limited to, all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. All records required to be maintained by this permit shall be made available in either hard copy or electronic format to DEQ representatives upon request.

[IDAPA 58.01.01.211, 5/1/94]

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Excess Emissions

9.11 The permittee shall comply with the procedures and requirements of IDAPA 58.01.01.130–136 for excess emissions due to start-up, shut-down, scheduled maintenance, safety measures, upsets, and breakdowns.

[IDAPA 58.01.01.130–136, 4/5/00]

Certification

9.12 All documents submitted to DEQ—including, but not limited to, records, monitoring data, supporting information, requests for confidential treatment, testing reports, or compliance certification—shall contain a certification by a responsible official. The certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document(s) are true, accurate, and complete.

[IDAPA 58.01.01.123, 5/1/94]

False Statements

9.13 No person shall knowingly make any false statement, representation, or certification in any form, notice, or report required under this permit or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.125, 3/23/98]

Tampering

9.14 No person shall knowingly render inaccurate any monitoring device or method required under this permit or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.126, 3/23/98]

Transferability

9.15 This permit is transferable in accordance with procedures listed in IDAPA 58.01.01.209.06.

[IDAPA 58.01.01.209.06, 4/11/06]

Severability

9.16 The provisions of this permit are severable, and if any provision of this permit to any circumstance is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

[IDAPA 58.01.01.211, 5/1/94]

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Statement of Basis

Permit to Construct No. P-2011.0132
Project ID 62264

Rexburg Facility of Basic American Foods, a Division of Basic American, Inc.
Rexburg, Idaho

Facility ID 065-00008

Proposed for EPA Review

November 27, 2019
Shawnee Chen, PE
Senior Air Quality Engineer

The purpose of this Statement of Basis is to satisfy the requirements of IDAPA 58.01.01.et seq, Rules for the Control of Air Pollution in Idaho, for issuing air permits.

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ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

AAC	acceptable ambient concentrations
AACC	acceptable ambient concentrations for carcinogens
acfm	actual cubic feet per minute
AMU	air makeup unit
AP-42	EPA's Compilation of Air Emissions Factors
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
BAF	Rexburg Facility of Basic American Foods, a Division of Basic American, Inc.
BMP	best management practices
Btu	British thermal units
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CAS No.	Chemical Abstracts Service registry number
CBP	concrete batch plant
CEMS	continuous emission monitoring systems
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CI	compression ignition
CMS	continuous monitoring systems
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	CO_2 equivalent emissions
COMS	continuous opacity monitoring systems
DEQ	Department of Environmental Quality
dscf	dry standard cubic feet
EL	screening emission levels
EPA	U.S. Environmental Protection Agency
FEC	Facility Emissions Cap
GHG	greenhouse gases
gph	gallons per hour
gpm	gallons per minute
gr	grains (1 lb = 7,000 grains)
HAP	hazardous air pollutants
HHV	higher heating value
HMA	hot mix asphalt
hp	horsepower
hr/yr	hours per consecutive 12 calendar month period
ICE	internal combustion engines
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
iwg	inches of water gauge
km	kilometers
lb/hr	pounds per hour
lb/qtr	pound per quarter
m	meters
MACT	Maximum Achievable Control Technology
mg/dscm	milligrams per dry standard cubic meter
MMBtu	million British thermal units
MMscf	million standard cubic feet
MMV	MicroMist Venturi
MRU	Material Recovery Unit

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NAAQS	National Ambient Air Quality Standard
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operation and maintenance
O_2	oxygen
PAH	polyaromatic hydrocarbons
PC	permit condition
PCB	polychlorinated biphenyl
PERF	Portable Equipment Relocation Form
PM	particulate matter
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
POM	polycyclic organic matter
ppm	parts per million
ppmw	parts per million by weight
PSD	Prevention of Significant Deterioration
psi	pounds per square inch
psig	pounds per square inch gauge
PTC	permit to construct
PTC/T2	permit to construct and Tier II operating permit
PTE	potential to emit
PW	process weight rate
RAP	recycled asphalt pavement
RFO	reprocessed fuel oil
RICE	reciprocating internal combustion engines
Rules	*Rules for the Control of Air Pollution in Idaho*
scf	standard cubic feet
SCL	significant contribution limits
SIP	State Implementation Plan
SM	synthetic minor
SM80	synthetic minor facility with emissions greater than or equal to 80% of a major source threshold
SO_2	sulfur dioxide
SO_x	sulfur oxides
T/day	tons per calendar day
T/hr	tons per hour
T/yr	tons per consecutive 12 calendar month period
T2	Tier II operating permit
TAP	toxic air pollutants
TEQ	toxicity equivalent
T-RACT	Toxic Air Pollutant Reasonably Available Control Technology
ULSD	ultra-low sulfur diesel
U.S.C.	United States Code
VOC	volatile organic compounds
yd^3	cubic yards
$\mu g/m^3$	micrograms per cubic meter

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FACILITY INFORMATION

Description

Rexburg Facility of Basic American Foods, a Division of Basic American, Inc. (BAF) produces a variety of dehydrated food products for both internal use and for external customers. Products include potato granules, formulated dehydrated food products, dehydrated whole and piece food products, and animal feed. BAF uses a variety of dehydration technologies to produce products to meet exacting customer specifications. The main sources of air emissions include boilers, dryers, dehydration lines, pneumatic material transfer, and packaging operations. Steam for plant operations is provided by boilers 1A and 2A with Boiler 2 and the Kipper & Sons boiler as the backup boilers.

Materials transport occurs both internally within a processing activity and externally to transfer materials between processes, to place them into or take them out of bulk storage, or to transport them to packaging and load-out activities. BAF uses air suspension systems to transport granules and most formulated products; these suspension processes include air slides and pneumatic bulk transfer operations. BAF also uses belt and bucket conveyors at various locations in its operations to transport raw materials, products in processing, and finished products. All bucket and belt conveyors are entirely contained within enclosed buildings. BAF also uses wet flumes to transport raw potatoes. Forklifts are used to transfer tote containers within the plant. Materials recovery units (primarily cyclones and baghouses) are integral to the operation of all unit processes in which granules or formulated products are suspended in air.

BAF operates packaging equipment to fill product containers with bulk product. Spices and flavoring may be added to the bulk product during the packaging process. Dust pickups located within the packaging area exhaust to the atmosphere through baghouses.

Raw materials are received on site by truck. Granules can be received by rail as well as by truck. All shipments are by rail or truck. Trucks are also used to move potatoes to and from the onsite cellars.

Plant process heating is provided by both direct firing with natural gas and indirect heating using steam supplied by facility boilers. Plant space heating is by natural gas.

Plant products are described as follows.

Dehydrated potato granules

Potato granules are individual potato cells prepared from raw potatoes by cooking, followed by gentle drying. Granules typically range from 50 to 120 microns in size. Most of the granules produced at the Rexburg Plant are used at the Rexburg Plant; occasionally granules are shipped to other BAF plants for use in products produced at those plants.

Dehydrated piece food products

BAF prepares dehydrated piece food products by dehydrating cooked and/or blanched foods. These foods can be either whole vegetables or vegetable pieces. Piece products range up to several inches in diameter.

Food processing byproducts

Sellable food fractions and off-specification materials that are not suitable for use in other products are produced as by-products of plant processes. BAF uses various materials classification processes to segregate, collect, and transport these byproducts. Food byproducts are transferred directly to load-out operations after collection without further processing beyond collection.

Air suspension unit processes are also used to classify materials and to remove unsuitable fractions from the production stream.

Food processing by-products are produced from food fractions that are not suitable for sale as primary products.

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Permitting History

The following information was derived from a review of the permit files available to DEQ. Permit status is noted as active and in effect (A), superseded (S), or terminated (T).

Issue Date	Project Number	Project	Status	History Explanation
July 30, 1980	n/a	Initial letter to construct (no PTC number assigned) the Kipper & Sons boiler.	S	Replaced by 4/30/81 letter.
April 30, 1981	n/a	Letter amended to revise test dates.	S	Replaced 7/30/80 letter. Replaced by 5/08/84 letter.
May 8, 1984	n/a	Letter amended to clarify coal/wood input limits.	S	Replaced 4/30/81 letter. Replaced by 065-00008 (12/11/02).
December 11, 2002	065-00008 (T1-9512-145-1)	Initial T1.	S	Initial T1. Replaced by T1-060513.
April 16, 2008	T1-060513	Renewal.	S	Replaced 065-00008. Replaced by T1-2008.0053.
June 10, 2008	T2-030515	Initial T2/PTC required by T1-060513.	S	Initial T2. Replaced by T2-2008.0109.
June 10, 2008	T1-2008.0053	Significant modification to incorporate T2-030515.	S	Replaced T1-2008.0053. Replaced by T1-2008.0053 Project 10/8/08.
October 8, 2008	T2-2008.0109	Revision to incorporate Kipper Boiler processing ranges, and PTC new/modified sources.	S	Replaced 5/08/84 letter and T2-030515. Replaced by P-2011.0132.
October 8, 2008	T1-2008.0110	Significant modification to incorporate T2-2008.0109.	S	Replaced T1-2008.0053. Replaced by T1-2008.0110 Project 60591.
January 19, 2011	T1-2008.0110 Project 60591	Administrative amendment to update Boiler 2 description.	S	Replaced T1-2008.0110. Replaced by T1-2010.0110 Project 61063.
June 1, 2012	P-2011.0132 Project 60943	Conversion of T2-2008.0109 to P-2011.0132.	S	Replaced T2-2008.0109. Replaced by P-2011.0132 Project 61459.
October 5, 2012	T1-2008.0110 Project 61063	Administrative amendment to incorporate P-2011.0132 Project 60943.	S	Replaced T1-2008.0110 Project 60591. Replaced by T1-2012.0066 Project 61126.
July 23, 2013	T1-2012.0066 Project 61126	Renewal.	S	Replaced T1-2008.0110 Project 61063. Replaced by T1-2008.0110 Project 61605.
October 7, 2015	P-2011.0132 Project 61459	PTC replacement potato dehydration production line.	S	Replaced P-2011.0132 Project 60943. Replaced by P-2011.0132 Project 62057.
May 31, 2016	T1-2012.0066 Project 61605	Administrative amendment to incorporate P-2011.0132 Project 61459.	S	Replaced T1-2008.0110 Project 61126. Replaced by T1-2018.0008 Project 61995.
May 11, 2018	P-2011.0132 Project 62057	DEQ-initiated revision for typographical correction.	S	Replaced P-2011.0132 Project 61459. Replaced by P-2011.0132 Project ID 62264.
July 18, 2018	T1-2018.0008 Project 61995	Renewal.	A	Replaced T1-2012.0066 Project 61605.

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Issue Date	Project Number	Project	Status	History Explanation
May 17, 2019	P-2011.0132 Project 62134	PTC modification to install a new dehydration line and replace two boilers and a belt dryer.	T (Will be terminated upon issuance of this permit	Replaced P-2011.0132 Project 62057.
XX XX 2019	P-2011.0132 Project 62264	PTC modification to increase production of Process A, to install a new flake line and to replace a belt dryer in Process B, and to install two new boilers to replace Boiler 1, to make the other two existing boilers as backup boilers, and to limit annual steam production of Kipper boiler.	A	Modifying and replacing P-2011.0132 project 62057 issued on May 11, 2018 This PTC terminates P-2011.0132 project 62134 issued on May 17, 2019, as if P-2011.0132 project 62134 has never been issued. Refer to the explanations under Application Scope section for details.

Application Scope

This PTC is for a modification at an existing Tier I facility.

This permitting action is for the following changes at BAF:

- Install two new natural gas-fired boilers with low-NOx burners,
- Remove the option to fire coal in Kipper & Sons boiler, limit its annual steam usage, and use it as a backup or standby unit,
- Remove Boiler 1,
- Use the existing Boiler 2 largely as a backup or standby unit and only operate when Kipper & Sons boiler is not operating,
- Install a new potato flake production line in Process B, specifically, install four steam-heated flake drum dryers with two wet scrubbers each control emissions from two drum dryers,
- Replace an existing steam-heated belt dryer (associated with the existing stacks denoted 613/614, 615/616, and 638) in Process B with a natural gas-fired belt dryer being relocated from BAF Blackfoot facility in Idaho,
- Increase maximum daily production rate of Process A,
- Install seven new NG direct-fired air make-up units associated with the expansion, and
- Relocate Kipper & Sons boiler wood fuel storage pile

In October 19, 2018, BAF submitted a 15-day pre-permit construction application. The pre-permit construction was approved, and PTC No. P-2011.0132 project 62134 was issued on May 17, 2019.

Prior to the issuance of the May 17, 2019 permit, BAF requested to change the application scope (e.g., keeping the wood-fired Kipper & Sons boiler as a backup steam source instead of removing it completely.) Because the construction had begun under the 15-day pre-permit construction approval, to avoid compliance complications, DEQ went ahead with the issuance of the permit.

To address the above application scope change and to include additional changes, BAF has submitted this application to entirely replace the October 19, 2018 permit application and consequently to terminate the May 17, 2019 PTC which was issued based on the 2018 permit application.

As a result, this permitting action will be process as a modification to PTC No. P-2011.0132 project 62057 issued on May 11, 2018 and will terminate PTC No. P-2011.0132 project 62134 issued on May 17, 2019, as if PTC No. P-2011.0132 project 62134 has never been issued.

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Application Chronology

July 11, 2019	DEQ received an application.
July 1, 2019	DEQ received an application fee
August 5 and 7, 2019	DEQ received additional information
August 8, 2019	DEQ determined that the application was complete.
September 25, 2019	DEQ made available the draft permit and statement of basis for peer and regional office review.
October 2, 2019	DEQ made available the draft permit and statement of basis for applicant review.
October 22 – November 21, 2019	DEQ provided a public comment period and EPA review on the proposed action.
November 27, 2019	DEQ provided a proposed permit for EPA 45-day review on the proposed action.

TECHNICAL ANALYSIS

Emissions Units and Control Equipment

Table 1 EMISSIONS UNIT AND CONTROL EQUIPMENT INFORMATION

Source ID No.	Sources	Control Equipment
Boilers		
KIPPER	Kipper & Sons Boiler Manufacturer: Kipper & Sons Model: N/A S/N: 1300 Heat input rating: 90.0 MMBtu/hr Maximum steam production rate: 65,000 lb/hr Fuel: wood Date installed: 1981 Permitted annual steam production rate: 189,800,000 lb/yr	Multiclone and Wet Scrubber in series
BOILER2	Boiler 2 Manufacturer: Murray Model: MCF3-43 S/N: 10509 Heat input rating: 49.9 MMBtu/hr Maximum steam production rate: 40,000 lb/hr Fuels: natural gas Date installed: 2010	None
BLR1A	Boiler 1A Manufacturer: Indeck Keystone Model: KD3.0068 Type D Heat input rating: 98 MMBtu/hr Maximum steam production rate: 80,600 lb/hr Fuel: natural gas Date of construction: 2018	Low-NO_x burner
BLR2A	Boiler 2A Manufacturer: Indeck Keystone Model: KD3.0068 Type D Heat input rating: 98 MMBtu/hr Maximum steam production rate: 80,600 lb/hr Fuel: natural gas Date of construction: 2018	Low-NO_x burner
Process A		
7020	Cooler/Dryer 7020 (Cooler vent), 43,333 lb/hr	None
7101	Cooler/Dryer 7101 (Dryer, 6.5 MMBtu/hr, natural gas-fired), 21,667 lb/hr	None

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Source ID No.	Sources	Control Equipment
7102	Cooler/Dryer 7102 (Dryer, 6.5 MMBtu/hr, natural gas-fired), 21,667lb/hr	None
7019	Cooler/Dryer 7019 (Dryer, 6.6 MMBtu/hr, steam and natural gas), 43,333 lb/hr	None
7001	Cooler/Dryer 7001 (Dryer, steam-heated), 5,417 lb/hr	None
7027	Cooler/Dryer 7027 (Cooler), 5,417 lb/hr	None
7006	Material Recovery Unit 7006, 43,333 lb/hr	None
Process B		
P4A, P4BCD	Proctor 4 Dryer (a belt dryer) 2,000 lb product/hr, natural gas-fired Stage A with one stack: 8.8 MMBtu/hr (Winnox 0200) Stage BCD with one stack: 8.8 MMBtu/hr (Winnox 0200) and 2.0 MMBtu/hr (Winnox 0100)	Low-NO_x burners
5034	Material Recovery Unit 5034	None
5037	Cooler/Dryer 5037 (Cooler/dryer vent, dryer is steam heated)	None
4000	Cooler/Dryer 4000 (Dryer, steam heated)	None
228	Cooler/Dryer 228 (Dryer, natural gas-fired, 16.1 MMBtu/hr that is 9.66 MMBtu/hr for the first exhaust and 6.44 MMBtu/hr for the second exhaust)	None
234	Cooler/Dryer 234 (Second exhaust from dryer 228)	None
707	Material Recovery Unit 707 (fabric filter)	None
725	Material Recovery Unit 725 (fabric filter)	None
8	Material Recovery Unit 8 (fabric filter)	None
5001	Material Recovery Unit 5001	None
5000	Material Recovery Unit 5000 (fabric filter)	None
432	Material Recovery Unit 432 (fabric filter)	None
322	Material Recovery Unit 322	None
572	Material Recovery Unit 572 (vent from material recovery cyclone in animal feed load-out system)	None
33	Vegetable Dryer M33 (Dryer, natural gas-fired, 2.7 MMBtu/hr)	None
44	Vegetable Dryer M44 (Dryer, natural gas-fired, 2.75 MMBtu/hr)	None
56	Vegetable Dryer M56 (Dryer, natural gas-fired, 1.6 MMBtu/hr)	None
62	Vegetable Dryer M62 (Dryer, natural gas-fired, 1.6 MMBtu/hr)	None
86	Vegetable Dryer M86 (Dryer, steam heated)	None
FLK_N	Flake Drum Dryer #1, steam-heated, 3,000 lb/hr	Venturi Wet Scrubber
	Flake Drum Dryer #2, steam-heated, 3,000 lb/hr	
FLK_S	Flake Drum Dryer #3, steam-heated, 3,000 lb/hr	Venturi Wet Scrubber
	Flake Drum Dryer #4, steam-heated, 3,000 lb/hr	
Flake AMU #1	Flake Air Makeup Unit #1, 4.86 MMBtu/hr	Low-NO_x burner
Flake AMU #2	Flake Air Makeup Unit #2, 4.86 MMBtu/hr	Low-NO_x burner
Flake Wet Process AMU#3	Flake Wet Process Air Makeup Unit #3, 2.86 MMBtu/hr	Low-NO_x burner
SLAB AMU#4	SLAB Air Makeup Unit #4, 1.29 MMBtu/hr	Low-NO_x burner
Potato Cleaning AMU#5	Potato Cleaning Air Makeup Unit #5, 0.72 MMBtu/hr	Low-NO_x burner
Boiler Room North AMU#6	Boiler Room Air Makeup Unit #6, 2.50 MMBtu/hr	Low-NO_x burner
Boiler Room North AMU#7	Boiler Room Air Makeup Unit #7, 2.50 MMBtu/hr	Low-NO_x burner
n/a	Plant Space Heaters (30.8 MMBtu/hr)	None
RX-OBI1	Reyco Unit (13.2 MMBtu/hr), installed in 2014	None

Emissions Inventories

Potential to Emit

IDAPA 58.01.01 defines Potential to Emit as the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hours of

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operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is state or federally enforceable. Secondary emissions do not count in determining the potential to emit of a facility or stationary source.

Using this definition of Potential to Emit, an emission inventory was developed for the facility (see Appendix A) for this proposed project. Emissions estimates of criteria pollutant, HAP PTE were based on emission factors from AP-42, Section 1.4 (7/98), manufacturers and vendors guarantee, source testing or measurements performed at the facility or at other facilities with similar equipment, and process information specific to the facility for this proposed project. Space heaters are assumed using 50% of 8,760 hours per year.

Uncontrolled Potential to Emit

Using the definition of Potential to Emit, uncontrolled Potential to Emit is then defined as the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall **not** be treated as part of its design **since** the limitation or the effect it would have on emissions **is not** state or federally enforceable.

The uncontrolled Potential to Emit is used to determine if a facility is a "Synthetic Minor" source of emissions. Synthetic Minor sources are facilities that have an uncontrolled Potential to Emit for regulated air pollutants or HAPs above the applicable Major Source threshold without permit limits. As the facility classification for Title V program was previously determined for permitting project, T2-2008.0109 dated October 8, 2008 (based upon T2-030515), the uncontrolled PTE will not be presented for this project.

Pre-Project Potential to Emit

Pre-project Potential to Emit is used to establish the change in emissions at a facility as a result of this project.

This is an existing facility. Therefore, post project emissions from the previous permitted project can be used for pre-project emissions for this project. The post project emissions calculated for permitting project, P-2011.0132 project 61457, dated October 7, 2015, will be presented as the pre-project PTE except for $PM_{10}/PM_{2.5}$ emissions from stacks 7019, 322, and 572 as discussed in the footnotes e) & f) of the following Table.

Table 2 PRE-PROJECT POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Emissions Unit	$PM_{10}/PM_{2.5}$		SO_2		NO_X		CO[c]		VOC		CO_2e[d]
	lb/hr[a]	T/yr[b]	lb/hr[a]	T/yr[b]	lb/hr[a]	T/yr[b]	lb/hr[a]	T/yr[b]	lb/hr[a]	T/yr[b]	T/yr[b]
Kipper & Sons Boiler	16.3	71.20	48.53	214.00	25.27	110.70	51.34	224.88	2.71	10.97	76,869
Boiler 1	0.39	1.70	0.12	0.54	5.10	22.33	4.28	18.76	0.28	1.23	27,331
Boiler 2	0.37	1.63	0.12	0.51	4.89	21.43	4.11	18.00	0.27	1.18	26,227
Cooler/Dryer 7020	0.41	1.82	0	0	0	0	0	0	0	0	0
Cooler/Dryer 7101	2.16	9.47	0.12	0.51	0.33	1.42	1.69	7.40	0.04	0.15	3,416
Cooler/Dryer 7102	2.16	9.47	0.12	0.51	0.33	1.42	1.69	7.40	0.04	0.15	3,416
Cooler/Dryer 7019 [e]	0.80	3.48	0.22	0.96	0.33	1.45	1.72	7.52	0.04	0.16	3,469
Cooler/Dryer 7001	0.23	1.03	0.03	0.11	0	0	0	0	0	0	0
Cooler/Dryer 7027	0.04	0.18	0	0	0	0	0	0	0	0	0
Material Recovery Unit 7006	0.12	0.54	0	0	0	0	0	0	0	0	0
Material Recovery Unit 5034	0.02	0.07	0	0	0	0	0	0	0	0	0
Cooler/Dryer 5037	1.29	5.66	1.87	8.19	0	0	0	0	0	0	0
Cooler/Dryer 4000	1.72	7.53	0.26	1.14	0	0	0	0	0	0	0
Cooler/Dryer 228	1.10	4.80	0.19	0.84	0.48	2.12	2.51	11.00	0.05	0.23	5,077
Cooler/Dryer 234	0.31	1.37	0.06	0.28	0.32	1.41	1.67	7.33	0.03	0.15	3,385
Cooler/Dryer 638	1.09	4.80	0.17	0.74	0	0	0	0	0	0	0
Cooler/Dryer 613/614	0.85	3.74	0.13	0.56	0	0	0	0	0	0	0
Cooler/Dryer 615/616	0.24	1.05	0.04	0.16	0	0	0	0	0	0	0
Material Recovery Unit 707	0.00	0.01	0	0	0	0	0	0	0	0	0
Material Recovery Unit 725	0.05	0.21	0	0	0	0	0	0	0	0	0
Material Recovery Unit 8	0.05	0.21	0	0	0	0	0	0	0	0	0
Material Recovery Unit 5001	0.24	1.07	0	0	0	0	0	0	0	0	0

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Emissions Unit	$PM_{10}/PM_{2.5}$		SO_2		NO_X		CO[c]		VOC		CO_2e[d]
	lb/hr[a]	T/yr[b]	lb/hr[a]	T/yr[b]	lb/hr[a]	T/yr[b]	lb/hr[a]	T/yr[b]	lb/hr[a]	T/yr[b]	T/yr[b]
Material Recovery Unit 5000	0.05	0.21	0	0	0	0	0	0	0	0	0
Material Recovery Unit 432	0.05	0.21	0	0	0	0	0	0	0	0	0
Material Recovery Unit 322[f]	0.00	0.00	0	0	0	0	0	0	0	0	0
Material Recovery Unit 572[f]	0.06	0.25	0	0	0	0	0	0	0	0	0
Vegetable Dryer M33	0.44	1.34	0.06	0.20	0.08	0.34	0.14	0.63	0.15	0.64	
Vegetable Dryer M44	0.27	0.83	0.04	0.12	0.08	0.35	0.15	0.64	0.15	0.65	
Vegetable Dryer M56	0.12	0.36	0.02	0.06	0.05	0.20	0.09	0.37	0.09	0.38	
Vegetable Dryer M62	0.02	0.07	0.01	0.04	0.05	0.20	0.09	0.37	0.09	0.38	
Vegetable Dryer M86	0.01	0.02	0.01	0.03	0	0	0	0	0	0	0
Heaters	0.23	0.50	0.07	0.16	1.54	3.37	8.01	17.54	0.17	0.36	16,188
Pre-project Totals	**31.19**	**134.83**	**52.19**	**229.66**	**38.85**	**166.74**	**77.49**	**249.00**	**4.11**	**16.63**	**99,000**

a) Controlled average emission rate in pounds per hour is a daily average, based on the proposed daily operating schedule and daily limits.
b) Controlled average emission rate in tons per year is an annual average, based on the proposed annual operating schedule and annual limits.
c) CO emissions are required to be less than 249.00 T/yr.
d) Greenhouse gas emissions are required to be less than 99,000 Tyr.
e) As discussed in the application for this project, the $PM_{2.5}$ and PM_{10} PTE for stack 7019 was revised based on an updated emission factor developed after testing of a similar stack at the BAF Blackfoot Facility. The test report is provided in Appendix C of the application. This updated emission factor is used to calculate both pre-project and post-project PTE.
f) As discussed in the application for this project, the PTE for all particulate matter species for stacks 322 and 572 was revised to correct for an erroneous (high) operating rate used in issuance of PTC P-2011.0132, Project ID 61459, October 7, 2015. The adjustment reduces estimated emissions from these stacks.

Note: The highlighted emissions units in the table above will be removed as a result of this project.

Post Project Potential to Emit

Post project Potential to Emit is used to establish the change in emissions at a facility and to determine the facility's classification as a result of this project. Post project Potential to Emit includes all permit limits resulting from this project.

An emission inventory was developed for the facility (see Appendix A) associated with this proposed project. Emissions estimates of criteria pollutant, HAP PTE were based on emission factors from AP-42, Section 1.4 (7/98), manufacturers and vendors guarantees, source testing or measurements performed at the facility or at other facilities with similar equipment, and process information specific to the facility for this proposed project. Space heaters are assumed using 50% of 8,760 hours per year.

Table 3 POST PROJECT POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS [a), b), c)]

Source Description	CO		NOx		SO_2		$PM_{2.5}$		PM_{10}		VOC	
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Boiler 1A	7.37	32.01	1.89	8.05	0.06	0.25	0.73	3.20	0.73	3.20	0.54	2.34
Boiler 2A	7.37	32.01	1.89	8.05	0.06	0.25	0.73	3.20	0.73	3.20	0.54	2.34
Kipper Boiler	60.25	87.97	21.58	31.51	2.25	3.29	13.57	19.81	13.57	19.81	3.18	4.65
Boiler 2	4.11	18.00	4.89	21.43	0.12	0.51	0.37	1.63	0.37	1.63	0.27	1.18
Cooler/Dryer 7020	0.14	0.32	0.05	0.10	0.00	0.00	0.44	1.93	0.44	1.93	0.00	0.01
Cooler/Dryer 7101	2.17	8.46	0.49	1.79	0.13	0.54	2.35	10.27	2.35	10.27	0.05	0.17
Cooler/Dryer 7102	2.17	8.45	0.49	1.79	0.13	0.54	2.35	10.27	2.35	10.27	0.05	0.17
Cooler/Dryer 7019	2.06	8.28	0.45	1.72	0.23	1.02	0.89	3.92	0.90	3.92	0.04	0.17
Cooler/Dryer 7001	0.06	0.13	0.02	0.04	0.03	0.12	0.25	1.09	0.25	1.09	0.00	0.00
Cooler/Dryer 7027	0.05	0.10	0.02	0.03	0.00	0.00	0.04	0.19	0.04	0.19	0.00	0.00
Material Recovery Unit 7006	0.04	0.08	0.01	0.03	0.00	0.00	0.13	0.57	0.13	0.57	0.00	0.00
Material Recovery Unit 5034	0.02	0.04	0.01	0.01	0.00	0.00	0.02	0.07	0.02	0.07	0.00	0.00
Cooler/Dryer 5037	0.19	0.42	0.06	0.14	1.87	8.19	1.29	5.66	1.29	5.66	0.01	0.01
Cooler/Dryer 4000	0.50	1.10	0.16	0.36	0.26	1.14	1.72	7.53	1.72	7.53	0.01	0.03
Cooler/Dryer 228	2.81	11.65	0.58	2.33	0.19	0.84	1.10	4.80	1.10	4.80	0.06	0.25
Cooler/Dryer 234	2.11	8.29	0.46	1.72	0.06	0.28	0.31	1.37	0.31	1.37	0.04	0.18
Vegetable Dryer M33	0.26	0.90	0.12	0.43	0.06	0.20	0.44	1.34	0.44	1.34	0.15	0.65

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Source Description	CO		NOx		SO_2		$PM_{2.5}$		PM_{10}		VOC	
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Vegetable Dryer M44	0.18	0.70	0.09	0.37	0.04	0.12	0.27	0.83	0.27	0.83	0.15	0.65
Vegetable Dryer M56	0.13	0.47	0.06	0.23	0.02	0.06	0.12	0.36	0.12	0.36	0.09	0.38
Vegetable Dryer M62	0.15	0.49	0.07	0.24	0.01	0.04	0.02	0.07	0.02	0.07	0.09	0.38
Vegetable Dryer M86	0.12	0.26	0.04	0.09	0.01	0.03	0.01	0.02	0.01	0.02	0.00	0.01
Flake North (two flake drums)	0.33	0.72	0.27	0.59	0.00	0.01	0.45	0.46	0.45	1.99	0.03	0.06
Flake South (two flake drums)	0.33	0.72	0.27	0.59	0.00	0.01	0.45	0.46	0.45	1.99	0.03	0.06
Proctor 4 Belt Dryer A Stage [e)]	1.94	7.76	0.38	1.41	0.01	0.02	0.42	1.82	0.42	1.82	0.06	0.23
Proctor 4 Belt Dryer BCD Stages [e)]	2.16	8.72	0.38	1.41	0.01	0.03	1.73	7.56	1.73	7.56	0.06	0.26
Material Recovery Unit 707	0.02	0.05	0.01	0.02	0.00	0.00	0.00	0.01	0.00	0.01	0.00	0.00
Material Recovery Unit 725	0.02	0.04	0.01	0.01	0.00	0.00	0.05	0.21	0.05	0.21	0.00	0.00
Material Recovery Unit 8	0.04	0.09	0.01	0.03	0.00	0.00	0.05	0.21	0.05	0.21	0.00	0.00
Material Recovery Unit 5001	0.01	0.03	0.00	0.01	0.00	0.00	0.24	1.06	0.24	1.06	0.00	0.00
Material Recovery Unit 5000	0.01	0.03	0.00	0.01	0.00	0.00	0.05	0.21	0.05	0.21	0.00	0.00
Material Recovery Unit 432	0.01	0.02	0.00	0.01	0.00	0.00	0.05	0.21	0.05	0.21	0.00	0.00
Material Recovery Unit 322	0.01	0.02	0.00	0.01	0.00	0.00	0.00	0.01	0.00	0.01	0.00	0.00
Material Recovery Unit 572	0.01	0.03	0.00	0.01	0.00	0.00	0.06	0.25	0.06	0.25	0.00	0.00
Fugitive Sources that do not meet the definition of "fugitive emissions" in Air Rules												
Main	2.88	6.32	0.94	2.05	0.01	0.02	0.01	0.01	0.01	0.02	0.09	0.19
Old Boilerhouse	0.78	1.71	0.15	0.33	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04
New Boilerhouse	0.12	0.26	0.10	0.21	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02
Flake	0.27	0.59	0.22	0.49	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.05
Receiving	0.46	1.01	0.18	0.40	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04
Woodpile	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	3.41	4.97
Post-Project Total Point Source Emissions[d)]	**101.68**	**248.3**	**36.35**	**88.0**	**5.56**	**17.5**	**31.14**	**91.6**	**31.15**	**94.6**	**9.02**	**19.5**

a) Controlled average emission rate in tons per year is an annual average, based on the proposed annual operating schedule and annual limits.
b) Tons per consecutive 12-month period.
c) Emissions from air makeup units are allocated to the processes and are included in the emissions of the above stacks and buildings. Refer to Appendix A "Emissions Summary" page and Appendix A.2 of this SOB for more details.
d) Exclude the emissions from Boiler 2 as it shall not operate simultaneously with Kipper & Sons boiler. Exclude fugitive emissions.
e) Use CO EF of 0.182 lb/MMBtu from November 2011 source test report Table 7 instead of CO EF of 84 lb/MMscf or 0.08235 lb/MMBtu from AP-42.

Note: The highlighted emissions units in the table above will be installed as a result of this project.

Change in Potential to Emit

The change in facility-wide potential to emit is used to determine if a public comment period may be required and to determine the processing fee per IDAPA 58.01.01.225. The following table presents the facility-wide change in the potential to emit for criteria pollutants. With change in PTE, the facility is no longer a synthetic minor PSD source for CO but a PSD minor source.

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Table 4 CHANGES IN POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Source	$PM_{10}/PM_{2.5}$		SO_2		NO_X		CO		VOC	
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Pre-Project Potential to Emit	31.19	134.83	52.19	229.66	38.85	166.74	77.49	249.00	4.11	16.63
Post Project Potential to Emit	31.15	94.6	5.56	17.5	36.35	88.0	101.68	248.3	5.2	13.0
Changes in Potential to Emit	**-0.04**	**-40.23**	**-46.63**	**-212.16**	**-2.50**	**-78.74**	**24.19**	**-0.70**	**1.09**	**-3.63**

Non-Carcinogenic TAP Emissions

A summary of the estimated PTE for emissions increase of non-carcinogenic toxic air pollutants (TAP) is provided in the following table.

Pre- and post-project, as well as the change in, non-carcinogenic TAP emissions for the emissions units involved in the project are presented in the following table:

Table 5 PRE- AND POST PROJECT POTENTIAL TO EMIT FOR NON-CARCINOGENIC TOXIC AIR POLLUTANTS

Non-Carcinogenic Toxic Air Pollutants	Pre-Project 24-hour Average Emissions Rates for Units at the Facility (lb/hr)	Post Project 24-hour Average Emissions Rates for Units at the Facility (lb/hr)	Change in 24-hour Average Emissions Rates for Units at the Facility (lb/hr)	Screening Emission Level (lb/hr)	Exceeds Screening Level? (Y/N)
Dichlorobenzene	0.00E-03	4.52E-05	4.52E-05	2.00E+01	N
Hexane	0.00E-03	6.77E-02	6.77E-02	1.20E+01	N
Pentane	0.00E-03	3.48E-01	3.48E-01	1.18E+02	N
Toluene	0.00E-03	1.28E-04	1.28E-04	2.50E+01	N
Chromium	0.00E-03	5.26E-05	5.26E-05	3.30E-02	N
Cobalt	0.00E-03	3.16E-06	3.16E-06	3.30E-03	N
Manganese	0.00E-03	1.43E-05	1.43E-05	3.33E-01	N
Selenium	0.00E-03	9.02E-07	9.02E-07	1.30E-02	N
Nitrous Oxide	0.00E-03	2.94E-01	2.94E-01	6.00E+00	N

None of the PTEs for non-carcinogenic TAP were exceeded as a result of this project. Therefore, modeling is not required for any non-carcinogenic TAP because none of the 24-hour average carcinogenic screening ELs identified in IDAPA 58.01.01.586 were exceeded.

Carcinogenic TAP Emissions

A summary of the estimated PTE for emissions increase of carcinogenic toxic air pollutants (TAP) is provided in the following table.

Pre- and post-project, as well as the change in, carcinogenic TAP emissions for the new emissions units involved in the project are presented in the following table:

Table 6 PRE- AND POST PROJECT POTENTIAL TO EMIT FOR CARCINOGENIC TOXIC AIR POLLUTANTS

Carcinogenic Toxic Air Pollutants	Pre-Project Annual Average Emissions Rates for Units at the Facility (lb/hr)	Post Project Annual Average Emissions Rates for Units at the Facility (lb/hr)	Change in Annual Average Emissions Rates for Units at the Facility (lb/hr)	Carcinogenic Screening Emission Level (lb/hr)	Exceeds Screening Level? (Y/N)
PAH (Idaho)		2.58E-05	2.58E-05	9.10E-05	N
POM (Idaho)	0.00E-03	4.29E-07	4.29E-07	2.00E-06	N
Benzene	0.00E-03	7.90E-05	7.90E-05	8.00E-04	N
Formaldehyde	**0.00E-03**	**2.82E-03**	**2.82E-03**	**5.10E-04**	**Y**

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Carcinogenic Toxic Air Pollutants	Pre-Project Annual Average Emissions Rates for Units at the Facility (lb/hr)	Post Project Annual Average Emissions Rates for Units at the Facility (lb/hr)	Change in Annual Average Emissions Rates for Units at the Facility (lb/hr)	Carcinogenic Screening Emission Level (lb/hr)	Exceeds Screening Level? (Y/N)
Arsenic	**0.00E-03**	**7.52E-06**	**7.52E-06**	**1.50E-06**	**Y**
Beryllium	0.00E-03	4.53E-07	4.53E-07	2.80E-05	N
Cadmium	**0.00E-03**	**4.15E-05**	**4.15E-05**	**3.70E-06**	**Y**
Chromium(VI)	**0.00E-03**	**2.63E-06**	**2.63E-06**	**5.60E-07**	**Y**
Nickel	**0.00E-03**	**7.91E-05**	**7.91E-05**	**2.70E-05**	**Y**

a) Polycyclic Organic Matter (POM) is considered as one TAP comprised of: benzo(a)anthracene, benzo(b)fluoranthene, benzo(k)fluoranthene, dibenzo(a,h)anthracene, chrysene, indeno(1,2,3-cd)pyrene, benzo(a)pyrene. The total is compared to benzo(a)pyrene.

Some carcinogenic TAP emissions increases have exceeded their respective ELs as a result of this project. Modeling is required for Arsenic compounds, cadmium and compounds, chromium IV, formaldehyde, and nickel and compounds because the annual average carcinogenic screening ELs identified in IDAPA 58.01.01.586 were exceeded.

Post Project HAP Emissions

The following table presents the post project potential to emit for HAP pollutants as submitted by the Applicant and verified by DEQ staff. See Appendix A for a detailed presentation of the calculations of these emissions for each emissions unit.

Table 7 HAZARDOUS AIR POLLUTANTS EMISSIONS POTENTIAL TO EMIT SUMMARY

Hazardous Air Pollutants	PTE (lb/hr)	PTE (T/yr)
EPA total listed HAPs	0.25	1.095
Totals	**0.25**	**1.095**

Ambient Air Quality Impact Analyses

As presented in the Modeling Memo in Appendix B, the estimated emission rates of PM_{10}, $PM_{2.5}$, NO_X, and CO from new emissions units of this project exceeded published DEQ modeling thresholds established in IDAPA 58.01.01.585-586 and in the State of Idaho Air Quality Modeling Guideline[1]. In addition, TAP emissions from this project were above applicable screening emission levels (ELs) for arsenic compounds, cadmium and compounds, chromium VI, formaldehyde, and nickel and compounds. Refer to the Emissions Inventories section for additional information concerning the emission inventories.

The applicant has demonstrated pre-construction compliance to DEQ's satisfaction that emissions from this facility will not cause or significantly contribute to a violation of any ambient air quality standard. The applicant has also demonstrated pre-construction compliance to DEQ's satisfaction that the emissions increase due to this permitting action will not exceed any acceptable ambient concentration (AAC) or acceptable ambient concentration for carcinogens (AACC) for toxic air pollutants (TAP).

An ambient air quality impact analyses document has been crafted by DEQ based on a review of the modeling analysis submitted in the application. That document is part of the final permit package for this permitting action (see Appendix B).

[1] Criteria pollutant thresholds in Table 2, State of Idaho Guideline for Performing Air Quality Impact Analyses, Doc ID AQ-011, September 2013.

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REGULATORY ANALYSIS

Attainment Designation (40 CFR 81.313)

The facility is located in Madison County, which is designated as attainment or unclassifiable for $PM_{2.5}$, PM_{10}, SO_2, NO_2, CO, and Ozone. Refer to 40 CFR 81.313 for additional information.

Facility Classification

The AIRS/AFS facility classification codes are as follows:

For THAPs (Total Hazardous Air Pollutants) Only:

A = Use when any one HAP has actual or potential emissions ≥ 10 T/yr or if the aggregate of all HAPS (Total HAPs) has actual or potential emissions ≥ 25 T/yr.

SM80 = Use if a synthetic minor (potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable limitations) and the permit sets limits ≥ 8 T/yr of a single HAP or ≥ 20 T/yr of THAP.

SM = Use if a synthetic minor (potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable limitations) and the potential HAP emissions are limited to < 8 T/yr of a single HAP and/or < 20 T/yr of THAP.

B = Use when the potential to emit without permit restrictions is below the 10 and 25 T/yr major source threshold

UNK = Class is unknown

For All Other Pollutants:

A = Actual or potential emissions of a pollutant are ≥ 100 T/yr.

SM80 = Use if a synthetic minor for the applicable pollutant (potential emissions fall below 100 T/yr if and only if the source complies with federally enforceable limitations) and potential emissions of the pollutant are ≥ 80 T/yr.

SM = Use if a synthetic minor for the applicable pollutant (potential emissions fall below 100 T/yr if and only if the source complies with federally enforceable limitations) and potential emissions of the pollutant are < 80 T/yr.

B = Actual and potential emissions are < 100 T/yr without permit restrictions.

UNK = Class is unknown.

Table 8 REGULATED AIR POLLUTANT FACILITY CLASSIFICATION

Pollutant	Uncontrolled PTE (T/yr)	Permitted PTE (T/yr)	Major Source Thresholds (T/yr)	AIRS/AFS Classification
$PM_{10}/PM_{2.5}$	>100	<100	**100**	SM
SO_2	>100	<100	**100**	SM
NO_X	>100	<100	**100**	SM
CO	>100	>100	**100**	A
VOC	<100	<100	**100**	B
HAP (single)	<10	<10	**10**	B
HAP (Total)	<25	<25	**25**	B

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Permit to Construct (IDAPA 58.01.01.201)

IDAPA 58.01.01.201 Permit to Construct Required

The permittee has requested that a PTC be issued to the facility for the proposed new emissions units involved in the project. Therefore, a permit to construct is required to be issued in accordance with IDAPA 58.01.01.220. This permitting action was processed in accordance with the procedures of IDAPA 58.01.01.200-228.

Tier II Operating Permit (IDAPA 58.01.01.401)

IDAPA 58.01.01.401 Tier II Operating Permit

The application was submitted for a permit to construct (refer to the Permit to Construct section), and an optional Tier II operating permit has not been requested. Therefore, the procedures of IDAPA 58.01.01.400–410 were not applicable to this permitting action.

Title V Classification (IDAPA 58.01.01.300, 40 CFR Part 70)

IDAPA 58.01.01.301 Requirement to Obtain Tier I Operating Permit

Post project facility-wide emissions from this facility have a potential to emit greater than 100 tons per year for CO as demonstrated previously in the Emissions Inventories Section of this analysis. Therefore, this facility is classified as a major facility, as defined in IDAPA 58.01.01.008.10.

PSD Classification (40 CFR 52.21)

40 CFR 52.21 Prevention of Significant Deterioration of Air Quality

The facility is not a major stationary source as defined in 40 CFR 52.21(b)(1), nor is it undergoing any physical change at a stationary source not otherwise qualifying under paragraph 40 CFR 52.21(b)(1) as a major stationary source, that would constitute a major stationary source by itself as defined in 40 CFR 52. Therefore in accordance with 40 CFR 52.21(a)(2), PSD requirements are not applicable to this permitting action. The facility is not a designated facility as defined in 40 CFR 52.21(b)(1)(i)(a), and does not have facility-wide emissions of any criteria pollutant that exceed 250 T/yr.

NSPS Applicability (40 CFR 60)

The two new natural gas-fired boilers (Boiler 1A and Boiler 2A) and the existing natural gas-fired boiler (Boiler 2) are subject to 40 CFR 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units because each unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 100 MMBtu/h or less, but greater than or equal to 10 MMBtu/hr.

The existing boiler (Boiler 2) is not being modified as a result of this project. Therefore, refer to the Statement of Basis for permit P-2011.0132, project 60943, dated June 1, 2012, for the compliance discussion of Subpart Dc.

Kipper & Sons Boiler was installed in 1981 and is not subject to 40 CFR 60 Subpart Dc. The removal of coal as a fuel is not a "modification" as defined in 40 CFR 60.

Detailed requirements of the subpart will be included in the Tier I operating permit.

NESHAP Applicability (40 CFR 61)

The project is not subject to any NESHAP requirements in 40 CFR 61.

GACT/MACT Applicability (40 CFR 63)

Kipper & Sons boiler is subject to 40 CFR 63 Subpart JJJJJJ - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources. The applicable requirements are included in the existing Tier I operating permit.

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Permit Conditions Review

This section describes only those permit conditions that have been added, revised, modified or deleted as a result of this permitting action. Old permit refers to PTC No. P-2011.0132 of project 62057, issued on May 11, 2018.

Permit Condition 1.1 describes the proposed project.

Permit Condition 1.3 states that this PTC modifies and replaces PTC No. P-2011.0132 project 62057, issued on May 11, 2018 and terminates PTC No. P-2011.0132 project 62134, issued on May 17, 2019, as if PTC No. P-2011.0132 project 62134 was not issued. (See Permit Scope section for additional information.)

Table 1.1 was updated to reflect the existing equipment being removed and the new equipment being installed as a result of this project.

Facility-Wide Conditions

Permit Condition 2.2 specifies the testing methods.

KIPPER BOILER

Revised Permit Condition 3.1

Revised Permit Condition 3.1 describe that the permittee has requested to eliminate the option of burning coal. Therefore the use of coal as a fuel to Kipper & Sons boiler shall be made inoperative. In addition, Kipper & Sons boiler will be used as a backup or standby boiler with an annual steam production limit of 189,800,000 pound per year.

Revised Permit Condition 3.3

Permit Condition 3.3 establishes emissions limits for Kipper & Sons boiler. These $PM_{2.5}$, PM_{10}, NOx, and CO emissions rates are based on burning wood only and are used in the modeling analysis. The short term $PM_{2.5}$, PM_{10}, and CO (1-hr and 8-hr) ambient impacts from this project are 65%, 18%, 16% and 34% of the respective significant impact levels. The annual $PM_{2.5}$ ambient impact of this project is negligible. The facility-wide 1-hr NO_2 ambient impact is 95% of the NAAQS when Kipper & Sons boiler is used as a backup boiler and is 71% of the NAAQS when Boiler 2 is used as a backup boiler. The facility-wide annual NO_2 ambient impact is 18% of the NAAQS. In addition The CO PTE is 248.3 T/yr with an annual steam production limit for Kipper & Sons boiler. Without the steam production limit, the CO PTE would be greater than major source threshold of 250 T/yr.

Based on the above information and to ensure compliance with the standards, the emissions limits for $PM_{2.5}/PM_{10}$, and NOx are established. The annual emissions limits for Kipper & Sons boiler are included because Kipper & Sons boiler takes annual steaming production limits to ensure compliance with the standards. Emissions of other criteria pollutants should be inherently limited due to these emissions limits. The PM_{10} emissions limits are updated to reflect that the option of burning coal in Kipper & Sons boiler is eliminated. The CO source test and monitoring in the existing permit are kept as they were.

Remove Old Permit Condition 3.4

Revised Permit Condition 3.4 is replaced with "reserved". As a result of removing the ability to burn coal, SO_2 limit to keep facility-wide SO_2 below 250 T/yr is no longer needed.

Revised Permit Condition 3.5

The content related to burning coal is removed.

Revised Permit Conditions 3.6 and 3.7

Permit Conditions 3.6 and 3.7 are revised to permit Kipper & Sons boiler to burn wood exclusively and to remove the boiler's ability to burn coal.

Revised Permit Condition 3.8

Permit Condition 3.8 has limited the annual steam production rate to ensure compliance with the annual emissions limits in Table 3.2 and to limit Kipper's CO emissions below 88 T/yr, as one of the several factors to keep facility-wide CO PTE < 250 T/yr.

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Revised Permit Condition 3.9

Permit Condition 3.9 is revised to add $PM_{2.5}$ to the permit condition.

New Permit Condition 3.10

Permit Condition 3.10 regarding coal burning is replaced with the new content: Kipper & Sons boiler shall not be operating concurrently with Boiler 2. According to the modeling memo, to demonstrate compliance with the NAAQS, the Boiler 2 and Kippur boiler will only run exclusively.

Revised Permit Condition 3.15

Permit Condition 3.15 is revised to add annual steam production monitoring requirements. Any requirements related to burning coal are removed.

Replace old Permit Condition 3.16 with new content

Old Permit Condition 3.16 regarding coal is replaced with the new content. It reads as following:

"*3.16 Operation Requirement Monitoring*

The permittee shall keep records, such as Kipper boiler and Boiler 2 steaming production records containing date and time to demonstrate that the Kipper boiler does not operate concurrently with Boiler 2."

Permit Condition 3.28

Permit Condition 3.28 regarding CO source testing when burning wood-coal mixture is replace by NOx and CO source testing requirements when burning wood.

According to the modeling memo, the facility-wide 1-hr NO_2 ambient impact is 95% of the NAAQS when using Kipper & Sons boiler as a backup boiler. A one-time source test to demonstrate compliance with the NOx emissions limits is required because the EF used to estimate NOx emissions is based on a 1994 emissions evaluation report. The NOx EF could change after the boiler has been used for another 25 years since the source test.

A one-time source test to verify the CO EF is required because the EF used to estimate CO emissions is based on a 1994 emissions evaluation report and because even with operational limits, the CO PTE is 248.3 T/yr, which is very close to the major source threshold of 250 T/yr for PSD program. The operational limits are an annual steam production limit for Kipper & Sons boiler and the Kipper boilie and Boiler 2 not to operate simultaneously. Without these operational limits, the CO PTE would be greater than major source threshold of 250 T/yr. In addition, the CO EF could change after the boiler has been used for another 13 years since the 2006 source test.

Because Kipper & Sons boiler will be used as a backup or standby boiler, a five-year timeframe, or a DEQ approved test timeframe is given in the permit.

Permit Condition 3.29

A source test was performed on June 28, 2017. The measured PM_{10} emissions rate was 11.3 lb /hr at the average boiler steaming rate of 55,895 pounds per hour during the test. It would be 13.1 lb/hr if proportionate it to boiler's rated steam rate of 65,000 lb steam/hr. The proportionated emissions rate value is close to the PM_{10} emissions rate of 13.6 lb/hr estimated using the PM_{10} EF in the 1994 emissions evaluation report.

Because the boiler was tested in June 28, 2017, because the PM/PM_{10} emissions from Kipper & Sons boiler appear relatively stable; because Kipper & Sons boiler is subject to CAM requirements, and because the PM_{10} emissions rate in the revised permit is reduced from 16.3 lb/hr to 13.6 lb/hr; a 10-year timeframe is given in the permit. Because the emissions limits are the same for PM_{10} and $PM_{2.5}$, the permittee only need to perform PM_{10} source test to demonstrate compliance with the PM_{10} and $PM_{2.5}$ limits.

Remove Old Permit Condition 3.30

Permit Condition 3.30 regarding coal combustion is replaced by "reserved" as coal is no longer allowed to be burned in Kipper & Sons boiler.

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BOILER 2, BOILER 1A, AND BOILER 2A

Revised Permit Conditions 4.1, 4.2, 4.4 – 4.6

Permit Conditions 4.1, 4.2, 4.4 – 4.6 are revised to reflect the removal of Boiler 1 and installation of new Boiler 1A and Boiler 2A.

New Permit Condition 4.3

Permit Condition 4.3 establishes emissions limits for the three natural gas-fired boilers. The table also lists the emissions from air makeup units (AMUs) allocated to the boiler stacks. These $PM_{2.5}$, PM_{10}, NOx, and CO emissions rates are used in the modeling analysis. The short term $PM_{2.5}$, PM_{10}, and CO (1-hr and 8-hr) ambient impacts from this project are 65%, 18%, 16% and 34% of the respective significant impact levels. The annual $PM_{2.5}$ ambient impact from this project is negligible. The facility-wide 1-hr NO_2 ambient impact is 95% of the NAAQS when Kipper & Sons boiler is used as a backup boiler and is 71% of the NAAQS when Boiler 2 is used as a backup boiler. The facility-wide annual NO_2 ambient impact is 18% of the NAAQS. In addition, the CO PTE is 248.3 T/yr with the operational limits. Without the operational limits, the CO PTE would be greater than major source threshold of 250 T/yr.

Based on the above information and to ensure compliance with the standards, the emissions limits for $PM_{2.5}$, PM_{10}, NOx, and CO (refer to Section 8 of the permit for CO limit) are established. Because it is assumed that the boilers will be operating 8,760 hr/yr, annual emissions limits are inherently limited by the hourly limits and therefore are not included. Emissions of other criteria pollutants should be inherently limited due to these emissions limits.

For allocation AMUs emissions, refer to Appendix A for more details.

Revised Permit Condition 4.6

"Total gas combusted by Boilers 1A and 2A" is added, and Boiler 1 is removed. Also see discussions under Revised Permit Condition 8.3 in this section.

New Permit Conditions 4.7 and 4.8

Boiler 1A and 1B are new boilers. NOx impacts from the new boilers are less than 15% of the total impact according to DEQ's modeler. Therefore, just a one-time perform source test to demonstrate compliance with the NOx emissions limit is required. The permittee is required to monitor and record the boiler steaming rate during each source test.

$PM_{2.5}$ and PM_{10}

The $PM_{2.5}$ and PM_{10} emissions are estimated using the EFs from AP-42 in the revised EI spreadsheet. The EFs from EPA"NG_process_gas_LPG_PM_factors" spreadsheet could underestimate the emissions and were not used in the revised EI spreadsheet submitted on 10/7/2019 through email.

CO and NOx:

Emission factors for CO and NOx are based on the vendor emissions guarantee, expressed as ppmvd @ 3% oxygen.

PROCESS A (DRYING PROCESS AND MATERIAL TRANSFER SYSTEMS)

Revised Permit Condition 5.1

"This permitting action increases production limits of Process A from 61 T/day to 65 T/day." is added to PC 5.1.

Revised Permit Condition 5.3

Emissions limits for PM_{10} are revised to reflect emissions increase for stacks 7101 and 7102 as a result of production increase and emissions decrease for Stack 7019 as a result of its EF update.

Because the facility-wide 1-hr NO_2 ambient impact is 95% of the NAAQS when Kipper & Sons boiler is used as a backup boiler and is 71% of the NAAQS when Boiler 2 is used as a backup boiler, Permit Condition 5.3 establishes NOx emissions limits to ensure compliance with the 1-hr NOx NAAQS. The short term $PM_{2.5}$ ambient

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impacts from this project is 65% of the significant impact levels, therefore a full ambient impact analysis was not performed. To ensure project ambient impact below the significant level, Permit Condition 5.3 establishes $PM_{2.5}$ emissions limits.

Revised Permit Condition 5.4

This permitting action allows Process A throughput limit increase from 61 per 24-hour work day to 65 tons per 24-hour work day.

PROCESS B (DRYING PROCESS AND MATERIAL TRANSFER SYSTEMS

Table 6.1 was updated to reflect the existing equipment being removed and the new equipment being installed as a result of this project.

Revised Table 6.1

The existing steam-heated dryer with emissions points of Cooler/Dryer 638, Cooler/Dryer 613/614 and Cooler/Dryer 615/616 will be replaced by a natural gas-fired Proctor 4 Belt Dryer relocated from BAF Blackfoot facility. Four new steam-heated flake drum dryers are proposed to be installed. Table 6.1 is revised to reflect these changes in Process B.

Revised Permit Condition 6.3 and revised Table 6.2

Permit Condition 6.3 is revised to reflect the aforementioned changes as a result of this project.

Because the facility-wide 1-hr NO_2 ambient impact is 95% of the NAAQS when Kipper & Sons boiler is used as a backup boiler and is 71% of the NAAQS when Boiler 2 is used as a backup boiler, Permit Condition 6.3 establishes NOx emissions limits to ensure compliance with the 1-hr NOx NAAQS. The short term $PM_{2.5}$ ambient impacts from this project is 65% of the significant impact levels, therefore a full ambient impact analysis was not performed. To ensure project ambient impact below the significant level, Permit Condition 6.3 establishes $PM_{2.5}$ emissions limits. It is assumed that PM_{10} emissions are the same as $PM_{2.5}$ emissions for Process B.

Table 6.2 is revised to reflect the addition of the new dryers and to include $PM_{2.5}/PM_{10}$ and NOx emissions rates used in the modeling, but only the emissions units with 1-hr NO_2 emissions rate equal to or greater than 0.2 lb/hr are listed in the table. For other emissions points with 1-hr NO_2 emissions rate less than 0.2 lb/hr, please refer to the modeling memo for details.

Apparently there is a mistake in Table 6.2 of the old permit: while the total PM_{10} potential to emit of the stack group 4000, 228, and 234 is 3.13 lb/hr, Table 6.2 in the old permit allows "the arithmetic average of the emission rates from the combined 3 stacks in the group shall not exceed the listed emission limit: 3.2 lb/hr". The table is revised and mistakes are corrected.

The table also lists the emissions from air makeup units (AMUs) allocated to the boiler stacks. For allocation AMUs emissions, refer to Appendix A for more details.

Revised Permit Condition 6.4

Permit Condition 6.4 is revised to add production limit for the new flaker line. The flake line has four steam heated-drum dryers, each has a production rate of 3,000 lb/hr. The 24-hr flake line production rate is calculated as: 4 x (3,000 lb/hr) / (2000 lb/T) * (24 hr/24-hr work day) = 144 T/24-hr work day

The total production rate is changed from 304 T/24-hr work day to 448 T/24-hr work day, the sum of the existing production rate of 304 T/24-hr and the new flake line production rate of 144 T/24-hr work day.

New Permit Condition 6.7

Permit Condition 6.7 requires two Venturi scrubbers to be installed, and each controls emissions from two flake drum dryers as described in Table 6.1 of the permit.

New Permit Conditions 6.8 and 6.10

Permit Condition 6.8 in the draft permit is revised to add parameters and operating ranges taken from the scrubber proposal provided in the application and to address facility's comments. The inlet liquid flow rate of 328 gpm to MMV stage is provided by the vendor through email to BAF on 10/4/2019.

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New Permit Condition 6.11

Proctor 4 Belt Dryer

NOx emissions from Proctor 4 belt dryer are estimated using the vendor's guarantee of 25 ppm @3% O_2, The emissions from the dryer is relatively low, a test for NOx is not required for NOx emissions from Proctor 4 belt dryer.

$PM_{2.5}$ emissions rates are assumed to be the same as PM_{10} emissions rates. The PM_{10} emissions rates are estimated using EFs developed from the 2008 source test performed at Rexburg facility and using the allocation formulas developed based on November 2011 source testing of a similar belt drying production line at BAF Blackfoot Facility. A one-time source test is required to verify the PM_{10} EFs used for the EI calculation and to demonstrate compliance with $PM_{10}/PM_{2.5}$ emissions limits for the two stacks of Proctor 4 belt dryer.

Steam-Heated Flake Drum Dryers

NOx emissions from the scrubbers stacks are emissions from AMUs allocated to the stacks. The dying process itself does not emit NOx as it is steam-heated.

$PM_{2.5}$ emissions rates are assumed to be the same as PM_{10} emissions rates. The PM_{10} emissions are estimated using the EF developed based on source testing conducted on June 20-21, 2011 on the flake drums at the Gem State Processing facility in Heyburn, ID and then by applying vendor guaranteed 75% control efficiency of the Venturi scrubber that will be used to control PM emissions from the flake drum dryers. AFF one-time source test on one Venturi scrubber stack is required to verify the EF used for the EI calculation for the flake drum dryers and to demonstrate compliance with the emissions limits for the flake production line.

New Permit Condition 6.12

Permit Condition 6.12 specifies what parameters need to be monitoring during the test.

PLANT SPACE HEATERS

Revised Permit Condition 7.1

Permit Condition 7.1 is revised to reflect the installation of new space heaters.

Revised Permit Condition 7.2

Permit Condition 7.2 states that space heaters emissions are allocated to the process stacks. In other words, stack emissions rates used in the modeling analysis are the sum of emissions from processes and emissions allocated to stacks from the emissions of AMUs. Refer to Appendix A and B for more details.

FACILITY-WIDE CO EMISSION LIMIT

Permit Condition 8.1

Because the facility CO PTE is 248.3 T/yr, if the facility installs an exemption source, such as a 5 MMBtu/hr natural gas-fired heater in the future, the facility's CO PTE will be greater than 250 T/yr.

The agency's concern is not knowing the facility's classification when an emissions unit that emits CO is installed. To address this concern, Section 8 is developed.

PUBLIC REVIEW

Public Comment Period

A public comment period was made available to the public in accordance with IDAPA 58.01.01.209.05.c. The proposed permit was provided to EPA and affected state (i.e., State of Wyoming and Fort Hall Indian Reservation) for concurrent review. During this time, comments were submitted by BAF in response to DEQ's proposed action. Refer to the chronology for public comment period dates.

A response to public comments document has been crafted by DEQ based on comments submitted during the public comment period. That document is part of the final permit package for this permitting action.

ED_013256A_00004257-00021

Because the proposed permit is revised in response to comments received from BAF during the public comment period, DEQ is required by IDAPA 58.01.01.209.05.c.iv to send the revised proposed permit to EPA for review.

ED_013256A_00004257-00022

APPENDIX A – EMISSIONS INVENTORIES

APPENDIX B – AMBIENT AIR QUALITY IMPACT ANALYSES

APPENDIX C – FACILITY DRAFT COMMENTS

The following comments were received from the facility on October 8, 2019:

Permit Condition	Existing Language	Proposed Change	Justification	DEQ's Response
3.7	issueance	issuance	Spelling error.	corrected
3.10	shall not be operating	Shall not operate	Grammar correction.	corrected
3.12 through 6.11 (7 occurrences)	"Error! Reference source not found."	Remove	Correction.	removed
4.7	Conduct performance tests to measure $PM_{2.5}$ and PM_{10}.	Remove $PM_{2.5}$ and PM_{10} testing requirement.	Permit writer comment [A1] *Applicant:* *Recently, DEQ received a source test report for a natural gas-fired boiler. The EF from that test is about 1/3 of the AP-42 EF; it is definitely higher that the EF taken from the EPA spreadsheet that is used to estimate emissions for Boiler 1A and 2A here.* *I asked Tom to look at the impact when using AP-42 EF for Boiler 1A and 2A, the impact still < SIL.* *So I am open to remove $PM_{2.5}$ and PM_{10} test requirement if the facility chooses to submit a revise EI spreadsheet using AP-42 EF for $PM_{2.5}$ and PM_{10}. I will then be able to revise the $PM_{2.5}$ and PM_{10} emissions limits in PC 4.3 according to the revised EI if the facility chooses so.* BAF concurs. Revised EI spreadsheets were sent to DEQ permit writer on 10/7/19.	Revised $PM_{2.5}$ and PM_{10} emissions limits in PC 4.3 and removed $PM_{2.5}$ and PM_{10} testing requirement. Revised PTE table and PTE change table in the SOB.
6.8	***Venturi Scrubber Operating Parameters*** Each scrubber's operating parameters shall be maintained as follows: • The pressure drop across the Venturi scrubber throat shall be maintained between 17 inches of water. • The pressure drop across	***Venturi Scrubber Operating Parameters*** Each scrubber's operating parameters shall be maintained as follows: • The pressure drop across the Venturi scrubber throat shall be maintained between 17 inches of water or greater.	Clarification and consistency. See section 2.9.2 and 2.13 of Permit P-2017.0011. See also attached correspondence from the scrubber manufacturer (EnviroCare) regarding these operating parameters.	Permit Condition 6.8 in the draft permit is revised to add parameters and operating ranges taken from the scrubber proposal provided in the application and to address facility's comments, such as using the same approach as the ones in PTC No. P-2017.0011 issued on January 18, 2019 to Blackfoot Facility of Basic American Foods. As a result of the changes to PC 6.8, Permit Conditions 6.10 and 6.12 are also revised. Please refer to the revised Permit Conditions 6.8, 6.10 and 6.12 in the proposed permit.

Permit Condition	Existing Language	Proposed Change	Justification	DEQ's Response
	the Venturi scrubber shall be maintained between 17 to 25 inches of water. • The scrubbing liquid flow rate shall be equal to or greater than 380 gallons per minute.	• The scrubbing liquid flow rate (which includes both the venturi inlet water and the venturi throat water combined) shall be equal to or greater than 328 gallons per minute.		Note: I am open to revise the operating ranges if the manufacturer recommends difference ranges with explanations. I am aware of the following statement in p.2 of the scrubber proposal: "*All design numbers shown are for the future capacity process data, and turn down or optimization can occur for the current loading to meet guarantees a lower water flow and blow down limits.*"
6.11	rovisions	revisions	Spelling error.	Did not find it.
6.12	• The throughput from Process B and from the specific unit (i.e., flake drum dryer, Proctor 4 belt dryer) tested in tons of product per hour (T/hr) during each test run.	• The from the specific Process B unit (i.e., flake drum dryers or Proctor 4 belt dryer) tested in tons of product per hour (T/hr) during each test run.	Clarification.	Revised
8.1 through 8.4	Facility-Wide CO Emission Limit.	Remove all of Section 8, Facility-Wide CO Emission Limit.	Previously, the potential CO emissions for the facility exceeded 250 tons/yr. Accordingly, the facility-wide CO emissions limit of 249 tons/yr was created so that the facility would be a minor source for purposes of New Source Review. With the modifications included in this permit, the facility CO PTE is now less than 250 ton/yr. (See Statement of Basis Table 3 "POST PROJECT POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS".) Accordingly, there is no longer a need to have a specific 249 ton/yr limit on CO emissions.	The section is revised. Refer to discussions under FACILITY-WIDE CO EMISSION LIMIT section.

APPENDIX D – WET SCRUBBING EMISSION CONTROL SYSTEM PROPOSAL

APPENDIX E – PROCESSING FEE

	A	B	C	D
1			GENERAL INPUT PARAMETERS	
2	Parameter	Value	Units	Discussion
3	**General Parameters**			
4	raw potato moisture content	80%	-	generic value
5	barometric pressure - standard conditions	14.7	psi	
6	baromtric pressure at Rexburg @ 20 C	12.33		
7	barometric pressure at Rexburg @ 306 °F	13.03	psi	
8	NG, HHV	1020	BTU/scf	
9	FW, NO2	46		
10	FW, CO	28		
11	*Stoichiometric NG combustion parameters*			
12	Fd, dry exhaust gas factor	8710	dscf/MMBtu	From Table 19-2, EPA Test Method 19
13	Fw, wet exhaust gas factor	10610	wscf/MMBtu	From Table 19-2, EPA Test Method 19
14	*AP-42 Natural Gas Combustion Emission factors*			
15	PM2.5	7.6	lb/MMscf	AP-42, Section 1.4 (7/98).for small boilers < 100 MMBtu. All PM counted as
16	PM10	7.6	lb/MMscf	AP-42, Section 1.4 (7/98).for small boilers < 100 MMBtu. All PM counted as PM10
17	NOx (uncontrolled)	100	lb/MMscf	AP-42, Section 1.4 (7/98).for small boilers < 100 MMBtu
18	SO_2	0.6	lb/MMscf	AP-42, Section 1.4 (7/98).for small boilers < 100 MMBtu
19	CO	84	lb/MMscf	AP-42, Section 1.4 (7/98).for small boilers < 100 MMBtu
20	VOC	5.5	lb/MMscf	AP-42, Section 1.4 (7/98).for small boilers < 100 MMBtu
21	Pb	0.0005	lb/MMscf	AP-42, Section 1.4 (7/98).for small boilers < 100 MMBtu
22	**Flake Operations and Emissions**			
23	Number of drums	4		
24	Operating rate per drum	3,000	lb actual/hr	
25	Maximum Steam Demand per drum	18,000	lb/hr	
26	*Flake Exhaust Data*			
27	exhaust rate	34000	acfm/drum	from "Drum Dryer Air Permit Flow Sheet 2018.08.25.pdf"
28	exhaust temperature	120	°F	
29	*Flake Process PM Emissions Data*			
30	Estimated PM emission rate, Gem flakers	0.730	lb/hr, bone dry solids	From Emissions Inventory in May 18, 2017 "Permit-to-Construct Modification Application" for Gem State Processing Heyburn. Emissions calculations based on June 20-21, 2011 stack test, as reported in application Emission Inventory..
31	operating rate, Gem State flakers, dry	2,250	lb dry/hr	From May 18, 2017 "Permit-to-Construct Modification Application" for Gem State Processing Heyburn
32	flake moisture content	7%		process knowledge
33	*Flake scrubber*			
34	Exhaust temp	115	°F	incoming air stream is saturated, so no evaporative cooling. Minimal temperature drop due to sensible heat losses.
35	stack diameter	60	inches	
36	PM2.5/PM10 removal efficiency	75%		vendor guarantee
37				
38	**AMU data**			
39	Flake North #1	4.86	MMBtuh	see AMU calcs workbook
40	Flake North #2	4.86	MMBtuh	see AMU calcs workbook
41	Flake South	2.86	MMBtuh	see AMU calcs workbook
42	Slab	1.29	MMBtuh	see AMU calcs workbook
43	Potato Cleaning	0.72	MMBtuh	see AMU calcs workbook
44	Boiler Room North	2.50	MMBtuh	see AMU calcs workbook
45	Boiler Room North	2.50	MMBtuh	see AMU calcs workbook
46	NOx emission	50	ppmv @ 3% O_2	from "Drum Dryer Air Permit Flow Sheet 2018.08.09.pdf"
47	NOx emission - Maxon NP-LE burner	100	ppmv @ 3% O2	burner cut sheet
48	CO emission	100	ppmv @ 3% O_2	from "Drum Dryer Air Permit Flow Sheet 2018.08.09.pdf"
49	**Boilers 1A and 2A**			
50	*Operating data*			
51	Heat Input	98	MMBtuh	Indeck Keystone boiler data sheet - proposal qu24561. 7/23/2018
52	Max steam rate	80,600		Indeck Keystone boiler data sheet - proposal qu24561. 7/23/2018
53	excess air	15.00%		Indeck Keystone boiler data sheet - proposal qu24561. 7/23/2018
54	oxygen content in flue gas	2.97%		Indeck Keystone boiler data sheet - proposal qu24561. 7/23/2018
55	exhaust temperature	306	°F	Indeck boiler data sheet
56	MW of flue gas	27.83		based on stoichiomtric combustion of methane and 15% excess air
57	flue gas	87219	lb/hr	Indeck Keystone boiler data sheet - proposal qu24561. 7/23/2018
58	*Emissions data*			
59	NOx emissions	15	ppmvd @ 3% O2	Project includes 9 ppmvd ultra-low NOx burners. Burners can be tuned to 15 ppmvd to provide greater flame stability.
60	CO emissions	100	ppmvd @ 3% O2	boiler mfr guarantee
61	PM10 - primary	7.6	lb/MMscf	AP-42. Table 1.4-2
62	PM2.5 - primary	7.6	lb/MMscf	
63	**P4 Replacement Dryer data**			
64	*General operations data*			
65	production rate	2000	lb/hr	per discussion with JSK 5/29/2019
66	*Process PM Emissions*			
67	Process PM10 emission factor	1.0	lb/1000 lb produced	Same as measured emissions from Dec 2008 stack test of Rexburg Proctor #3. Also, 2007 stack test of Nonpareil Proctor 5A stage = 0.93 lb PM/ton. Process emission factor selected is twice that measured rate, rounded up.

	A	B	C	D
1			GENERAL INPUT PARAMETERS	
2	Parameter	Value	Units	Discussion
68	Filterable PM10 fraction	70%		December 2008 stack test results for Rexburg Proctor 3 (Stack 410/411)
69	Filterable PM10 emission factor	0.70	lb/1000 lb produced	
70	consdensable PM10 fraction	30%		December 2008 stack test results for Rexburg Proctor 3 (Stack 410/411)
71	Condensible PM10 emission factor	0.30	lb/1000 lb produced	
72	*Allocation of PM emissions across process*			
73	Cumulative Filterable PM	$\%D^{1.8}$	cumulative % of filterable PM emitted	from "Review of Results of November 2011 Source Testing at Blackfoot Facility of Basic American Foods and Development of Revised Emission Factors", pp. 7-14 (Coal Creek Environmental Associates, LLC, April 2012)
74	Cumulative condensible PM	1.17*%D	cumulative % of condensibe PM emitted for %D ≤ 85%	
75		1.0	cumulative % of condensibe PM emitted for %D > 85%	
76	*NOx Emission factors for process burners*			
77	Winnox 0200	25.0	ppmv at 3% oxygen	Winnox 0200 data sheet
78	Winnox 0100	10.0	ppmv at 3% oxygen	Winnox 0100 data sheet
79	*Dryer Stage data*			
80	Stage A			
81	inlet moisture	81.5%		same as stack CBB in Blackfoot Facility DREX-3 line
82	burner capacity (Winnox 0200)	8.8	MMBtuh	Rick Havlicak email to John Kirkpatrick, July 19, 2018. Burners assigned to stacks Stephen Nelson email to John Kirkpatrick, July 23, 2018.
83	Stages BCD			
84	burner capacity (Winnox 0200)	8.0	MMBtuh	Rick Havlicak email to John Kirkpatrick, July 19, 2018. Burners assigned to stacks Stephen Nelson email to John Kirkpatrick, July 23, 2018.
85	burner capacity (Winnox 0100)	2.0	MMBtuh	Rick Havlicak email to John Kirkpatrick, July 19, 2018. Burners assigned to stacks Stephen Nelson email to John Kirkpatrick, July 23, 2018.
86	inlet moisture	60.0%		same as stack CTQ in Blackfoot Facility DREX-3 line
87	exit moisture	6.5%		email Rick Havlicak to Stephen Nelson, July 23, 2018.
88	*Exhaust data*			
89	Stage A Exhaust			
90	flow	18,750	acfm	P_ID_FREV_7_23_2018.pdf
91	temp	145	°F	PFD 18101-PID-03-RB_PACKET_7_18_2018.pdf
92	diameter	35.8	inches	8/2/2018 e-mail from Rick Havlicak
93	Stage BCD-1 Exhaust			
94	flow	18,750	acfm	PFD 18101-PID-03-RB_PACKET_7_18_2018.pdf
95	temp	145	°F	PFD 18101-PID-03-RB_PACKET_7_18_2018.pdf
96	diameter	41.8	inches	8/2/2018 e-mail from Rick Havlicak
97	Stage D-2 Exhaust			
98	flow	2,000	acfm	email 7/19/2018 Rick Havlicak to John Kirkpatrick
99	temp	90	°F	PFD 18101-PID-03-RB_PACKET_7_18_2018.pdf
100	**Plant Space Heaters**			
101	*Standard burner units*			
102	installed capacity	30.8	MMBtuh	30.8 MMBtuh capacity noted in original inventory, pluse 2014 installation of 13.2 MMBtuh Reyco unit
103	NOx emission factor	0.05	lb NOx/MMBTU	Based on results of emission measurements of similar bar burners completed at the BAF Blackfoot Plant.
104	CO emission factor	0.26	lb CO/MMBtu	Based on results of emission measurements of similar bar burners completed at the BAF Blackfoot Plant. No difference between hourly and annual emission factors.
105	*RX-OBI1*			
106	capacity	13.2	MMBtuh	
107	NOx emission factor	0.082	lb NOx/MMBTU	Based on burner manufacturer estimated NOx emissions of 70 ppmvd @ 3% O2 for a burner with heat input of 1 MMBtu/ft. Converted to lb/MMBtu based on stoichiometric combustion of methane with excess air to provide 3% O2 in combusted air stream. All NOx expressed as NO2.
108	CO emission factor	0.071	lb CO/MMBtu	Based on burner manufacturer estimated CO emissions of 100 ppmvd @ 3% O2 for a burner with heat input of 1 MMBtu/ft. Converted to lb/MMBtu based on stoichiometric combustion of methane with excess air to provide 3% O2 in combusted air stream.
109	**Existing Equipment**			
110	*Kipper Boiler*			
111	Max steam rate	65,000	lb/hr	Permit T1-2018.0008, Table 1.1
112	Max Heat rate	90	MMBtuh	
113	NOX emissions from facility permiting statements	25.27	lb/hr	There is an unexplained discrepancy in the potential NOx emissions for the Kipper Boiler between Permit T2-030515 and PTC P-2011.0132. For this permit
114	of PTE	110.7	ton/yr	
115	PM10/PM2.5 PTE			
116	PM10/PM2.5 emissions - hourly	16	lb/hr	Enforceable emissions limit.
117	PM10/PM2.5 emissions - annual	71	ton/yr	Enforceable emissions limit.
118	*Kipper Boiler firing data (wood only)*			from'RX Emsn_Invty 2012 base 1.3 (Tier I)'
119	Steam generation, hourly	65,000	lb/hour	from'RX Emsn_Invty 2012 base 1.3 (Tier I)'
120	steam generation, annual, post-project	189,800,000	lb/yr	Based on 33% duty, annual average
121	steam enthalpy input	1,000	Btu/lb of steam	from'RX Emsn_Invty 2012 base 1.3 (Tier I)'
122	boiler efficiency	72.2%		from'RX Emsn_Invty 2012 base 1.3 (Tier I)'
123	heat content of wood	7000	Btu/lb	from'RX Emsn_Invty 2012 base 1.3 (Tier I)'
124				
125				

	A	B	C	D
1			GENERAL INPUT PARAMETERS	
2	Parameter	Value	Units	Discussion
126	*Boiler 1*			
127	Max steam rate	40,000	lb/hr	Permit T1-2018.0008, Table 1.1
128	Max heat rate	52	MMBtuh	
129				
130	*Boiler 2*			Permit T1-2018.0008, Table 1.1
131	Max steam rate	40,000	lb/hr	
132		49.9	MMBtuh	
133				
134	*Existing Belt Dryer*			
135	Max operating rate	2500	lb/hr	Based on production data during baseline period
136	steam demand	8.43	lb steam/lb product	9/20/2018 email from Neil Woodgerd, BAF, to Stephen Nelson. Based on steam usage to date in 2018.
137	PM emission limits			
138	Stack 613/614	1.09	lb/hr	The Belt dryer has an enforceable emissions limit of 2.2 lb/hr. This limit is
139	Stack 615/616	0.85	lb/hr	assigned to stacks as identified in the PTE emission inventory for Permit T2-
140	Stack 638	0.24	lb/hr	030515, which is the permit in which this emissions limit was first established.
141				
142	*Process Equipment Heat Rates*			
143	7101	6.5	MMBtuh	
144	7102	6.5	MMBtuh	
145	7019	6.6	MMBtuh	
146	228	9.66	MMBtuh	
147	234	6.44	MMBtuh	
148	33	2.7	MMBtuh	from existing facility emission inventory
149	44	2.75	MMBtuh	
150	56	1.6	MMBtuh	
151	62	1.6	MMBtuh	
152	Heaters	30.8	MMBtuh	
153	RX-OBI1	13.2	MMBtuh	
154				
155	**Process Weight Information**			
156	Process B Process Weight Preproject	76,000	lb/hr	from Dec 2014 PTC application for addition of new production line
157	Preproject Process B potential emissions	9.35	lb/hr	from emission inventory submitted for 2018 Tier I permit renewal (*"RX Emsn_Invty 2018 Tier I (180118).xlsm"*)
158	Potential emissions from stacks 613/614, 615/616, and 638	2.2	lb/hr	from emission inventory submitted for 2018 Tier I permit renewal (*"RX Emsn_Invty 2018 Tier I (180118).xlsm"*)

	A	B	C	D	E	F	G	H	I	J	K
1											
2	**Process A Emission Factors**										
3		**Process Emissions, lb/1000 lbs**			**Combustion Emissions, lb/MMBtu**						
4	**Stack**	**PM10**	**PM2.5**	**SO2**	**PM10**	**PM2.5**	**SO2**	**NOx**	**CO**	**VOC**	**Lead**
5	7020	0.0102	0.0102	-			-				
6	7101	0.1060	0.1060	0.0050	0.0075	0.0075	0.0024	0.0510	0.2600	0.0050	4.90E-07
7	7102	0.1060	0.1060	0.0050	0.0075	0.0075	0.0024	0.0510	0.2600	0.0050	4.90E-07
8	7019	0.0195	0.0195	0.0050	0.0075	0.0075	0.0024	0.0510	0.2600	0.0050	4.90E-07
9	7001	0.0460	0.0460	0.0050			-				
10	7027	0.0080	0.0080	-			-				
11	7006	0.0030	0.0030	-			-				
12	8	0.0016	0.0016	-							
13	5001	0.008	0.008	-							
14	5000	0.0016	0.0016	-							
15	432	0.0016	0.0016	-							
16	322	0.008	0.008	-							
17	572	0.0375	0.0375	-							

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
2	Current PTE - from Statement of Basis for PTC P-2011.0132, Project ID 61459, Oct. 7, 2015, except where noted														
3	Emissions Unit	source id	PM10		PM2.5		SO_2		NO_X		CO[c]		VOC		CO_2e[d]
4			lb/hr[a]	T/yr[b]	lb/hr[a]	T/yr[b]	lb/hr[a]	T/yr[b]	lb/hr[a]	T/yr[b]	lb/hr[a]	T/yr[b]	lb/hr[a]	T/yr[b]	T/yr[b]
5	Point Sources														
6	Kipper Boiler	Kipper	16.30	71.20	16.30	71.20	48.53	214.00	25.27	110.70	51.34	224.88	2.71	10.97	76869.00
7	Boiler 1	Boiler1	0.39	1.70	0.39	1.70	0.12	0.54	5.10	22.33	4.28	18.76	0.28	1.23	27331.00
8	Boiler 2	Boiler2	0.37	1.63	0.37	1.63	0.12	0.51	4.89	21.43	4.11	18.00	0.27	1.18	26227.00
9	7020	7020	0.41	1.82	0.41	1.82	0	0	0	0	0	0	0	0	0
10	7101	7101	2.16	9.47	2.16	9.47	0.12	0.51	0.33	1.42	1.69	7.40	0.04	0.15	3416.00
11	7102	7102	2.16	9.47	2.16	9.47	0.12	0.51	0.33	1.42	1.69	7.40	0.04	0.15	3416.00
12	7019	7019	0.80	3.48	0.80	3.48	0.22	0.96	0.33	1.45	1.72	7.52	0.04	0.16	3469.00
13	7001	7001	0.23	1.03	0.23	1.03	0.03	0.11	0	0	0	0	0	0	0
14	7027	7027	0.04	0.18	0.04	0.18	0	0	0	0	0	0	0	0	0
15	7006	7006	0.12	0.54	0.12	0.54	0	0	0	0	0	0	0	0	0
16	5034	5034	0.02	0.07	0.02	0.07	0	0	0	0	0	0	0	0	0
17	5037	5037	1.29	5.66	1.29	5.66	1.87	8.19	0	0	0	0	0	0	0
18	4000	4000	1.72	7.53	1.72	7.53	0.26	1.14	0	0	0	0	0	0	0
19	228	228	1.10	4.80	1.10	4.80	0.19	0.84	0.48	2.12	2.51	11.00	0.05	0.23	5077.00
20	234	234	0.31	1.37	0.31	1.37	0.06	0.28	0.32	1.41	1.67	7.33	0.03	0.15	3385.00
21	638	638	1.09	4.80	1.09	4.80	0.17	0.74	0	0	0	0	0	0	0
22	613/614	613_614	0.85	3.74	0.85	3.74	0.13	0.56	0	0	0	0	0	0	0
23	615/616	615_616	0.24	1.05	0.24	1.05	0.04	0.16	0	0	0	0	0	0	0
24	M33	M33	0.44	1.34	0.44	1.34	0.06	0.20	0.08	0.34	0.14	0.63	0.15	0.64	
25	M44	M44	0.27	0.83	0.27	0.83	0.04	0.12	0.08	0.35	0.15	0.64	0.15	0.65	
26	M56	M56	0.12	0.36	0.12	0.36	0.02	0.06	0.05	0.20	0.09	0.37	0.09	0.38	
27	M62	M62	0.02	0.07	0.02	0.07	0.01	0.04	0.05	0.20	0.09	0.37	0.09	0.38	
28	M86	M86	0.01	0.02	0.01	0.02	0.01	0.03	0	0	0	0	0	0	0
29	707	707	0	0.01	0	0.01	0	0	0	0	0	0	0	0	0
30	725	725	0.05	0.21	0.05	0.21	0	0	0	0	0	0	0	0	0
31	8	8	0.05	0.21	0.05	0.21	0	0	0	0	0	0	0	0	0
32	5001	5001	0.24	1.05	0.24	1.05	0	0	0	0	0	0	0	0	0
33	5000	5000	0.05	0.21	0.05	0.21	0	0	0	0	0	0	0	0	0
34	432	432	0.05	0.21	0.05	0.21	0	0	0	0	0	0	0	0	0
35	322	322	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0	0	0
36	572	572	0.06	0.25	0.06	0.25	0	0	0	0	0	0	0	0	0
37	RX-OB11	-	0.10	0.22	0.10	0.22	0.03	0.07	1.08	2.36	0.94	2.05	0.07	0.31	
38	HEATERS	HEATERS	0.23	0.50	0.23	0.50	0.07	0.16	1.54	3.37	8.01	17.54	0.17	0.36	16188.00
39	**Totals**		**31.27**	**135.03**	**31.27**	**135.03**	**52.22**	**229.73**	**39.93**	**169.10**	**78.43**	**323.89**	**4.18**	**16.94**	**165378.00**
40															
41	Woodpile		0.01	0.03	0.00	0.00	0	0	0	0	0	0	3.41	14.92	
42															
43	Notes														
44	RX-OB11 and woodpile annual PTE from Statement of Basis for Permit No. T1-2018.0008, Project ID 61995. Hourly PTE from facility emission inventory.														
45	PM PTE for stack 7019 revised based on updated emission factor developed after testing of a similar stack at the BAF Blackfoot Facility.														
46	PM PTE for stacks 322 and 572 revised based on erroneous (high) operating rate used in prior permitting actions.														

	A	B	C	D
1	**CALCULATED VARIABLES - Boiler 1A and Boiler 2A Emissions**			
2	**Parameter**	**Value**	**Units**	**Basis**
3	Flue gas calculations			
4	Heat Input	98	MMBtuh	
5	Fd, dry exhaust gas factor	8710	dscf/MMBtu	From Table 19-2, EPA Test Method 19
6	Fw, wet exhaust gas factor	10610	wscf/MMBtu	From Table 19-2, EPA Test Method 19
7	Stoichiometric air flow	17330	wscfm	boiler heat rate*Fw
8	HHV, natural gas	1020	Btu/scf	
14				
15	Boiler NOx emission factor			
16	PPM, stack gas concentration	15	ppmvd NOx @3% O2	vendor guarantee
17	FW, formula weight	46	-	NOx as NO2
18	E, emissions	0.00000179	lb/dscf	=PPM*FW/(385.1*10^6)
19	Fa, Fd adjusted to 3% O2	10170	dscf/MMBtu @ 3% O2	=Fd*(20.9/(20.9-3))
20	heat rate emission factor	0.018	lb/MMBtu	=E*Fa
21	fuel rate emission factor	18.59	lb/MMscf NG	
22				
23	Boiler SO_2 emission factor			
24	fuel rate emission factor	0.6	lb/MMscf	AP-42, Section 1.4 (7/98).for small boilers < 100 MMBtu
25	heat rate emission factor	0.00059	lb/MMBtu	
26				
27	Boiler CO emission factor			
28	PPM, stack gas concentration	100	ppmvd @ 3% O2	boiler mfr guarantee
29	FW, formula weight	28	-	
30	E, emissions	0.00000727	lb/dscf	=PPM*FW/(385.1*10^6)
31	Fa, Fd adjusted to 3% O2	10170	dscf/MMBtu @ 3% O2	=Fd*(20.9/(20.9-3))
32	EFh, heat rate emission factor	0.074	lb/MMBtu	=E*Fa
33	EFf, fuel rate based emission factor	75.42	lb/MMscf NG	
34				
35	Boiler PM25 emission factor			
36	fuel rate emission factor	7.6	lb/MMscf	AP-42. Table 1.4-2
37	heat rate emission factor	0.00745	lb/MMBtu	lb/MMscf ÷ HHV NG
38				
39	Boiler PM10 emission factor			
40	fuel rate emission factor	7.6	lb/MMscf	AP-42. Table 1.4-2
41	heat rate emission factor	0.00745	lb/MMBtu	lb/MMscf ÷ HHV NG
42				
43	Boiler VOC emission factor			
44	fuel rate emission factor	5.5	lb/MMscf	AP-42, Section 1.4 (7/98).for small boilers < 100 MMBtu
45	heat rate emission factor	0.00539	lb/MMBtu	lb/MMscf ÷ HHV NG
46				
47	Boiler Pb emission factor			
48	fuel rate emission factor	5.00E-04	lb/MMscf	AP-42, Section 1.4 (7/98).for small boilers < 100 MMBtu
49	heat rate emission factor	4.90E-07	lb/MMBtu	lb/MMscf ÷ HHV NG

	A	B	C
1	**Constitutent**	**Emission Factor, lb/MMBtu**	**Reference**
2	SO2	0.025	From AP-42, Sec. 1.6 (9/03) for wood combustion.
3	NOx	0.240	Based on 0.332 lb NOx/000 lbs steam reported in 1994 Source Emission Evaluation Report. Converted to lb/MMBtu of fuel combusted based on 1000 Btu heat ouput per lb of steam and 72.2% boiler efficiency.
4	CO	0.669	Based on 0.927 lb CO/000 lbs steam reported in 1994 Source Emission Evaluation Report. Converted to lb/MMBtu of fuel combusted based on 1000 Btu heat ouput per lb of steam and 72.2% boiler efficiency.
5	PM	0.154	Based on 0.213 lb PM/0000 lbs steam (scrubbed emission) reported in 1994 Source Emission Evaluation Report. Converted to lb/MMBtu of fuel combusted based on 1000 Btu heat ouput per lb of steam and 72.2% boiler efficiency.
6	PM10	0.151	Based on AP-42, Sec. 1.6 (9/03), 98 percent of total TSP emitted is PM10 (for wood-fired boiler using multiclones and wet scrubber)
7	PM2.5	0.151	From AP-42, Sec. 1.6 (9/03), Table 1.6-5, PM10 and PM2.5 emissions are the same.
8	VOC	0.035	Based on 0.049 lb VOC/000 lbs steam reported in 1994 Source Emission Evaluation Report. Converted to lb/MMBtu of fuel combusted based on 1000 Btu heat ouput per lb of steam and 72.2% boiler efficiency.
9	Lead	4.80E-05	AP-42, Table 1.6-4 (9/03 update)
10	Acenaphthene	9.10E-07	AP-42, Table 1.6-3 (9/03 update)
11	Acenaphthylene	5.00E-06	AP-42, Table 1.6-3 (9/03 update)
12	Acetaldehyde	8.30E-04	AP-42, Table 1.6-3 (9/03 update)
13	Acetone	1.90E-04	AP-42, Table 1.6-3 (9/03 update)
14	Acetophenone	3.20E-09	AP-42, Table 1.6-3 (9/03 update)
15	Acrolein	4.00E-03	AP-42, Table 1.6-3 (9/03 update)
16	Anthracene	3.00E-06	AP-42, Table 1.6-3 (9/03 update)
17	Benzaldehyde	8.50E-07	AP-42, Table 1.6-3 (9/03 update)
18	Benzene	4.20E-03	AP-42, Table 1.6-3 (9/03 update)
19	Benzo(a)anthracene	6.50E-08	AP-42, Table 1.6-3 (9/03 update)
20	Benzo(a)pyrene	2.60E-06	AP-42, Table 1.6-3 (9/03 update)
21	Benzo(b)fluoranthene	1.00E-07	AP-42, Table 1.6-3 (9/03 update)
22	Benzo(e)pyrene	2.60E-09	AP-42, Table 1.6-3 (9/03 update)
23	Benzo(g,h,i)perylene	9.30E-08	AP-42, Table 1.6-3 (9/03 update)
24	Benzo(j,k)fluoranthene	1.60E-07	AP-42, Table 1.6-3 (9/03 update)
25	Benzo(k)fluoranthene	3.60E-08	AP-42, Table 1.6-3 (9/03 update)
26	Benzoic acid	4.70E-08	AP-42, Table 1.6-3 (9/03 update)
27	bis(2-Ethylhexyl)phthalate	4.70E-08	AP-42, Table 1.6-3 (9/03 update)
28	Bromomethane	1.50E-05	AP-42, Table 1.6-3 (9/03 update)
29	2-Butanone (MEK)	5.40E-06	AP-42, Table 1.6-3 (9/03 update)
30	Carbazole	1.80E-06	AP-42, Table 1.6-3 (9/03 update)
31	Carbon tetrachloride	4.50E-05	AP-42, Table 1.6-3 (9/03 update)
32	Chlorine	7.90E-04	AP-42, Table 1.6-3 (9/03 update)
33	Chlorobenzene	3.30E-05	AP-42, Table 1.6-3 (9/03 update)
34	Chloroform	2.80E-05	AP-42, Table 1.6-3 (9/03 update)
35	Chloromethane	2.30E-05	AP-42, Table 1.6-3 (9/03 update)
36	2-Chloronaphthalene	2.40E-09	AP-42, Table 1.6-3 (9/03 update)
37	2-Chlorophenol	2.40E-08	AP-42, Table 1.6-3 (9/03 update)
38	Chrysene	3.80E-08	AP-42, Table 1.6-3 (9/03 update)
39	Crotonaldehyde	9.90E-06	AP-42, Table 1.6-3 (9/03 update)
40	Decachlorobiphenyl	2.70E-10	AP-42, Table 1.6-3 (9/03 update)
41	Dibenzo(a,h)anthracene	9.10E-09	AP-42, Table 1.6-3 (9/03 update)
42	1,2-Dibromoethene	5.50E-05	AP-42, Table 1.6-3 (9/03 update)
43	Dichlorobiphenyl	7.40E-10	AP-42, Table 1.6-3 (9/03 update)
44	1,2-Dichloroethane	2.90E-05	AP-42, Table 1.6-3 (9/03 update)
45	Dichloromethane	2.90E-04	AP-42, Table 1.6-3 (9/03 update)
46	1,2-Dichloropropane	3.30E-05	AP-42, Table 1.6-3 (9/03 update)
47	2,4-Dinitrophenol	1.80E-07	AP-42, Table 1.6-3 (9/03 update)

	A	B	C
1	**Constitutent**	**Emission Factor, lb/MMBtu**	**Reference**
48	Ethylbenzene	3.10E-05	AP-42, Table 1.6-3 (9/03 update)
49	Fluoranthene	1.60E-06	AP-42, Table 1.6-3 (9/03 update)
50	Fluorene	3.40E-06	AP-42, Table 1.6-3 (9/03 update)
51	Formaldehyde	4.40E-03	AP-42, Table 1.6-3 (9/03 update)
52	Heptachlorobiphenyl	6.60E-11	AP-42, Table 1.6-3 (9/03 update)
53	Hexachlorobiphenyl	5.50E-10	AP-42, Table 1.6-3 (9/03 update)
54	Hexanal	7.00E-06	AP-42, Table 1.6-3 (9/03 update)
55	Hexane	0.00E+00	no emission factor listed in AP-42
56	Heptachlorodibenzo-p-dioxins	2.00E-09	AP-42, Table 1.6-3 (9/03 update)
57	Heptachlorodibenzo-p-furans	2.40E-10	AP-42, Table 1.6-3 (9/03 update)
58	Hexachlorodibenzo-p-dioxins	1.60E-06	AP-42, Table 1.6-3 (9/03 update)
59	Hexachlorodibenzo-p-furans	2.80E-10	AP-42, Table 1.6-3 (9/03 update)
60	HCl	1.90E-02	AP-42, Table 1.6-3 (9/03 update)
61	Indeno(1,2,3,c,d)pyrene	8.70E-08	AP-42, Table 1.6-3 (9/03 update)
62	Isobutyraldehyde	1.20E-05	AP-42, Table 1.6-3 (9/03 update)
63	Methane	2.10E-02	AP-42, Table 1.6-3 (9/03 update)
64	2-Methylnaphthalene	1.60E-07	AP-42, Table 1.6-3 (9/03 update)
65	Monochlorobiphenyl	2.20E-10	AP-42, Table 1.6-3 (9/03 update)
66	Naphthalene	9.70E-05	AP-42, Table 1.6-3 (9/03 update)
67	2-Nitrophenol	2.40E-07	AP-42, Table 1.6-3 (9/03 update)
68	4-Nitrophenol	1.10E-07	AP-42, Table 1.6-3 (9/03 update)
69	Octachlorodibenzo-p-dioxins	6.60E-08	AP-42, Table 1.6-3 (9/03 update)
70	Octachlorodibenzo-p-furans	8.80E-11	AP-42, Table 1.6-3 (9/03 update)
71	Pentachlorodibenzo-p-dioxins	1.50E-09	AP-42, Table 1.6-3 (9/03 update)
72	Pentachlorodibenzo-p-furans	4.20E-10	AP-42, Table 1.6-3 (9/03 update)
73	Pentachlorobiphenyl	1.20E-09	AP-42, Table 1.6-3 (9/03 update)
74	Pentachlorophenol	5.10E-08	AP-42, Table 1.6-3 (9/03 update)
75	Perylene	5.20E-10	AP-42, Table 1.6-3 (9/03 update)
76	Phenanthrene	7.00E-06	AP-42, Table 1.6-3 (9/03 update)
77	Phenol	5.10E-05	AP-42, Table 1.6-3 (9/03 update)
78	Phosphorus	2.70E-05	AP-42, Table 1.6-4 (9/03 update)
79	Propanal	3.20E-06	AP-42, Table 1.6-3 (9/03 update)
80	Propionaldehyde	6.10E-05	AP-42, Table 1.6-3 (9/03 update)
81	Pyrene	3.70E-06	AP-42, Table 1.6-3 (9/03 update)
82	Styrene	1.90E-03	AP-42, Table 1.6-3 (9/03 update)
83	2,3,7,8-Tetrachlorodibenzo-p-dioxins	8.60E-12	AP-42, Table 1.6-3 (9/03 update)
84	Tetrachlorodibenzo-p-dioxins	4.70E-10	AP-42, Table 1.6-3 (9/03 update)
85	2,3,7,8-Tetrachlorodibenzo-p-furans	9.00E-11	AP-42, Table 1.6-3 (9/03 update)
86	Tetrachlorodibenzo-p-furans	7.50E-10	AP-42, Table 1.6-3 (9/03 update)
87	Tetrachlorobiphenyl	2.50E-09	AP-42, Table 1.6-3 (9/03 update)
88	Tetrachloroethene	3.80E-05	AP-42, Table 1.6-3 (9/03 update)
89	o-Tolualdehyde	7.20E-06	AP-42, Table 1.6-3 (9/03 update)
90	p-Tolualdehyde	1.10E-05	AP-42, Table 1.6-3 (9/03 update)
91	Toluene	9.20E-04	AP-42, Table 1.6-3 (9/03 update)
92	Trichlorobiphenyl	2.60E-09	AP-42, Table 1.6-3 (9/03 update)
93	1,1,1-Trichloroethane	3.10E-05	AP-42, Table 1.6-3 (9/03 update)
94	Trichloroethene	3.00E-05	AP-42, Table 1.6-3 (9/03 update)
95	Trichlorofluoromethane	4.00E-05	AP-42, Table 1.6-3 (9/03 update)
96	2,4,6-Trichlorophenol	2.20E-08	AP-42, Table 1.6-3 (9/03 update)
97	Vinyl Chloride	1.80E-05	AP-42, Table 1.6-3 (9/03 update)
98	o-Xylene	2.50E-05	AP-42, Table 1.6-3 (9/03 update)
99	Antimony	7.90E-06	AP-42, Table 1.6-4 (9/03 update)
100	Arsenic	2.20E-05	AP-42, Table 1.6-4 (9/03 update)
101	Barium	1.70E-04	AP-42, Table 1.6-4 (9/03 update)
102	Beryllium	1.10E-06	AP-42, Table 1.6-4 (9/03 update)
103	Cadmium	4.10E-06	AP-42, Table 1.6-4 (9/03 update)
104	Chromium, total	2.10E-05	AP-42, Table 1.6-4 (9/03 update)

	A	B	C
1	**Constitutent**	**Emission Factor, lb/MMBtu**	**Reference**
105	Chromium, hexavalent	3.50E-06	AP-42, Table 1.6-4 (9/03 update)
106	Cobalt	6.50E-06	AP-42, Table 1.6-4 (9/03 update)
107	Copper	4.90E-05	AP-42, Table 1.6-4 (9/03 update)
108	Iron	9.90E-04	AP-42, Table 1.6-4 (9/03 update)
109	Lead	4.80E-05	AP-42, Table 1.6-4 (9/03 update)
110	Manganese	1.60E-03	AP-42, Table 1.6-4 (9/03 update)
111	Mercury	3.50E-06	AP-42, Table 1.6-4 (9/03 update)
112	Molybdenum	2.10E-06	AP-42, Table 1.6-4 (9/03 update)
113	Nickel	3.30E-05	AP-42, Table 1.6-4 (9/03 update)
114	Potassium	3.90E-02	AP-42, Table 1.6-4 (9/03 update)
115	Selenium	2.80E-06	AP-42, Table 1.6-4 (9/03 update)
116	Silver	1.70E-03	AP-42, Table 1.6-4 (9/03 update)
117	Sodium	3.60E-04	AP-42, Table 1.6-4 (9/03 update)
118	Strontium	1.00E-05	AP-42, Table 1.6-4 (9/03 update)
119	Tin	2.30E-05	AP-42, Table 1.6-4 (9/03 update)
120	Titanium	2.00E-05	AP-42, Table 1.6-4 (9/03 update)
121	Vanadium	9.80E-07	AP-42, Table 1.6-4 (9/03 update)
122	Yttrium	3.00E-07	AP-42, Table 1.6-4 (9/03 update)
123	Zinc	4.20E-04	AP-42, Table 1.6-4 (9/03 update)
124			
125			
126	TOC	0.039	AP-42, Table 1.6-3 (9/03 update)
127	VOC	0.017	AP-42, Table 1.6-3 (9/03 update)
128	N2O	0.013	AP-42, Table 1.6-3 (9/03 update)
129	HAP	3.87E-02	
130	POM	1.25E-04	
131	PCBs	7.93E-09	
132	DBFs	1.78E-09	

	A	B	C	D	E	F
1						
2						
3						
4	**Toxic and Hazardous Air Pollutant Emission Factors - NG Burners***					
5	**Air Pollutant**	**lb/MMBTU**	**Emission Factor Reference**	**EPA Hazardous Air Pollutant?**	**Idaho Toxic Air Pollutant?**	
6	POM Components					
7	Acenaphthene	1.76E-09	AP-42, Table 1.4-3	Yes	Yes (General PAH)	
8	Acenaphthylene	1.76E-09	AP-42, Table 1.4-3	Yes	Yes (General PAH)	
9	Anthracene	2.35E-09	AP-42, Table 1.4-3	Yes	Yes (General PAH)	
10	Benz(a)anthracene	1.76E-09	AP-42, Table 1.4-3	Yes	Yes (7-PAH Group)	
11	Benzo(a)pyrene	1.18E-09	AP-42, Table 1.4-3	Yes	Yes (7-PAH Group)	
12	Benzo(b)fluoranthene	1.76E-09	AP-42, Table 1.4-3	Yes	Yes (7-PAH Group)	
13	Benzo(g,h,i)perylene	1.18E-09	AP-42, Table 1.4-3	Yes	Yes (General PAH)	
14	Benzo(k)fluoroanthene	1.76E-09	AP-42, Table 1.4-3	Yes	Yes (7-PAH Group)	
15	Chrysene	1.76E-09	AP-42, Table 1.4-3	Yes	Yes (7-PAH Group)	
16	Dibenzo(a,h)anthracene	1.18E-09	AP-42, Table 1.4-3	Yes	Yes (7-PAH Group)	
17	7,12-Dimethylbenz(a)anthracene	1.57E-08	AP-42, Table 1.4-3	Yes	Yes (General PAH)	
18	Fluoranthene	2.94E-09	AP-42, Table 1.4-3	Yes	Yes (General PAH)	
19	Fluorene	2.75E-09	AP-42, Table 1.4-3	Yes	Yes (General PAH)	
20	Indeno(1,2,3-cd)pyrene	1.76E-09	AP-42, Table 1.4-3	Yes	Yes (7-PAH Group)	
21	2-Methylnaphthalene	2.35E-08	AP-42, Table 1.4-3	Yes	Yes (General PAH)	
22	3-Methylchloroanthene	1.76E-09	AP-42, Table 1.4-3	Yes	Yes (General PAH)	
23	Naphthalene	5.98E-07	AP-42, Table 1.4-3	Yes	Yes (General PAH)	
24	Phenanthrene	1.67E-08	AP-42, Table 1.4-3	Yes	Yes (General PAH)	
25	Pyrene	4.90E-09	AP-42, Table 1.4-3	Yes	Yes (General PAH)	
26	*PAH (Idaho)*	*6.73E-07*	*Summation of individual ID PAH components*	*Yes (EPA POM component)*	*C*	
27	*POM (Idaho)*	*1.12E-08*	*Summation of ID POM 7-PAH components*	*Yes (EPA POM component)*	*C*	
28	*POM (EPA)*	*6.85E-07*	*Sum of individual POM componnents*	*Yes*	-	
29	Benzene	2.06E-06	AP-42, Table 1.4-3	Yes	C	
30	Dichlorobenzene	1.18E-06	AP-42, Table 1.4-3	Yes	NC	
31	Formaldehyde	7.35E-05	AP-42, Table 1.4-3	Yes	C	
32	Hexane	1.76E-03	AP-42, Table 1.4-3	Yes	NC	
33	Pentane	2.55E-03	AP-42, Table 1.4-3	No	NC	
34	Toluene	3.33E-06	AP-42, Table 1.4-3	Yes	NC	
35	Arsenic	1.96E-07	AP-42, Table 1.4-4	Yes	C	
36	Beryllium	1.18E-08	AP-42, Table 1.4-4	Yes	C	
37	Cadmium	1.08E-06	AP-42, Table 1.4-4	Yes	C	
38	Chromium	1.37E-06	AP-42, Table 1.4-4	Yes	NC	
39	Chromium(VI)	6.85E-08	5% of chromium assumed to be Chromium(VI)‡	Yes (included in chromium)	C	
40	Cobalt	8.24E-08	AP-42, Table 1.4-4	Yes	NC	
41	Manganese	3.73E-07	AP-42, Table 1.4-4	Yes	NC	
42	Mercury	2.55E-07	AP-42, Table 1.4-4	Yes	No	
43	Nickel	2.06E-06	AP-42, Table 1.4-4	Yes	C	
44	Selenium	2.35E-08	AP-42, Table 1.4-4	Yes	NC	
45	Nitrous Oxide	2.16E-03	AP-42, Table 1.4-2	No	NC	
46	EPA Total HAPs	1.85E-03	Summation of individual EPA HAP components	Yes	No	
47	Largest Individual HAP	1.76E-03	Hexane	Yes	Yes	
48						
49	‡ See "AB 2588 Combustion Emission Factors", Ventura County APCD, May 17, 2001.					
50						
51	Based on 1020 BTU/scf natural gas heat content					

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**Changes in Potential To Emit for Criteria Air Pollutants**															
2	Emission Point		**CO**		**NOx**		**SO_2**		**PM2.5**		**PM10**		**VOC**		**Lead**	
3		Source ID	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
4	Post-Project PTE															
5	*Point Sources*															
6	Boiler 1A	BLR1A	7.37	32.01	1.89	8.05	0.06	0.25	0.74	3.23	0.74	3.23	0.54	2.34	4.8E-05	2.1E-04
7	Boiler 2A	BLR2A	7.37	32.01	1.89	8.05	0.06	0.25	0.74	3.23	0.74	3.23	0.54	2.34	4.8E-05	2.1E-04
8	Kipper Boiler	KIPPER	60.25	87.97	21.58	31.51	2.25	3.29	13.57	19.81	13.57	19.81	3.18	4.65	4.3E-03	6.3E-03
9	Boiler 2	BOILER2	4.11	18.00	4.89	21.43	0.12	0.51	0.37	1.63	0.37	1.63	0.27	1.18	2.4E-05	1.1E-04
10	7020	7020	0.14	0.32	0.05	0.10	0.00	0.00	0.45	1.94	0.45	1.94	0.00	0.01	2.0E-07	4.4E-07
11	7101	7101	2.17	8.46	0.49	1.79	0.13	0.54	2.36	10.31	2.36	10.31	0.05	0.17	3.8E-06	1.5E-05
12	7102	7102	2.17	8.45	0.49	1.79	0.13	0.54	2.36	10.31	2.36	10.31	0.05	0.17	3.8E-06	1.5E-05
13	7019	7019	2.06	8.28	0.45	1.72	0.23	1.02	0.91	3.95	0.91	3.95	0.04	0.17	3.7E-06	1.5E-05
14	7001	7001	0.06	0.13	0.02	0.04	0.03	0.12	0.25	1.10	0.25	1.10	0.00	0.00	8.1E-08	1.8E-07
15	7027	7027	0.05	0.10	0.02	0.03	0.00	0.00	0.05	0.19	0.05	0.19	0.00	0.00	6.4E-08	1.4E-07
16	7006	7006	0.04	0.08	0.01	0.03	0.00	0.00	0.13	0.57	0.13	0.57	0.00	0.00	5.2E-08	1.1E-07
17	5034	5034	0.02	0.04	0.01	0.01	0.00	0.00	0.02	0.07	0.02	0.07	0.00	0.00	2.7E-08	5.9E-08
18	5037	5037	0.19	0.42	0.06	0.14	1.87	8.19	1.30	5.68	1.30	5.68	0.01	0.01	2.6E-07	5.7E-07
19	4000	4000	0.50	1.10	0.16	0.36	0.26	1.14	1.74	7.57	1.74	7.57	0.01	0.03	6.9E-07	1.5E-06
20	228	228	2.81	11.65	0.58	2.33	0.19	0.84	1.11	4.83	1.11	4.83	0.06	0.25	5.1E-06	2.2E-05
21	234	234	2.11	8.29	0.46	1.72	0.06	0.28	0.33	1.41	0.33	1.41	0.04	0.18	3.8E-06	1.5E-05
22	M33	M33	0.26	0.90	0.12	0.43	0.06	0.20	0.44	1.35	0.44	1.35	0.15	0.65	1.7E-07	3.8E-07
23	M44	M44	0.18	0.70	0.09	0.37	0.04	0.12	0.27	0.83	0.27	0.83	0.15	0.65	3.7E-08	8.2E-08
24	M56	M56	0.13	0.47	0.06	0.23	0.02	0.06	0.12	0.36	0.12	0.36	0.09	0.38	6.0E-08	1.3E-07
25	M62	M62	0.15	0.49	0.07	0.24	0.01	0.04	0.02	0.07	0.02	0.07	0.09	0.38	7.6E-08	1.7E-07
26	M86	M86	0.12	0.26	0.04	0.09	0.01	0.03	0.01	0.03	0.01	0.03	0.00	0.01	1.7E-07	3.6E-07
27	Flake North	FLK_N	0.33	0.72	0.27	0.59	0.00	0.01	0.49	0.53	0.49	2.06	0.03	0.06	1.2E-06	2.6E-06
28	Flake South	FLK_S	0.33	0.72	0.27	0.59	0.00	0.01	0.49	0.53	0.49	2.06	0.03	0.06	1.2E-06	2.6E-06
29	P4A	P4A	1.94	7.76	0.38	1.41	0.01	0.02	0.43	1.84	0.43	1.84	0.06	0.23	4.7E-07	1.0E-06
30	P4BCD	P4BCD	2.16	8.72	0.38	1.41	0.01	0.03	1.74	7.59	1.74	7.59	0.06	0.26	4.7E-07	1.0E-06
31	707	707	0.02	0.05	0.01	0.02	0.00	0.00	0.00	0.01	0.00	0.01	0.00	0.00	3.1E-08	6.8E-08
32	725	725	0.02	0.04	0.01	0.01	0.00	0.00	0.05	0.21	0.05	0.21	0.00	0.00	2.2E-08	4.8E-08
33	8	8	0.04	0.09	0.01	0.03	0.00	0.00	0.05	0.22	0.05	0.22	0.00	0.00	5.8E-08	1.3E-07
34	5001	5001	0.01	0.03	0.00	0.01	0.00	0.00	0.24	1.06	0.24	1.06	0.00	0.00	1.7E-08	3.8E-08
35	5000	5000	0.01	0.03	0.00	0.01	0.00	0.00	0.05	0.21	0.05	0.21	0.00	0.00	1.7E-08	3.8E-08
36	432	432	0.01	0.02	0.00	0.01	0.00	0.00	0.05	0.21	0.05	0.21	0.00	0.00	1.3E-08	2.9E-08
37	322	322	0.01	0.02	0.00	0.01	0.00	0.00	0.00	0.01	0.00	0.01	0.00	0.00	1.0E-08	2.2E-08
38	572	572	0.01	0.03	0.00	0.01	0.00	0.00	0.06	0.25	0.06	0.25	0.00	0.00	1.9E-08	4.2E-08
39	*Fugitive Sources that do not meet the definition of "fugitive emissions" in Air Rules.*															
40	Main	AM_MAIN	2.88	6.32	0.94	2.05	0.01	0.02	0.11	0.24	0.11	0.24	0.09	0.19	4.0E-06	8.7E-06
41	Old Boilerhouse	AM_BLROLD	0.78	1.71	0.15	0.33	0.00	0.00	0.02	0.05	0.02	0.05	0.02	0.04	8.0E-07	1.7E-06
42	New Boilerhouse	AM_BLRNEW	0.12	0.26	0.10	0.21	0.00	0.00	0.01	0.03	0.01	0.03	0.01	0.02	4.3E-07	9.3E-07
43	Flake	AM_FLAKE	0.27	0.59	0.22	0.49	0.00	0.00	0.03	0.06	0.03	0.06	0.02	0.05	9.7E-07	2.1E-06
44	Receiving	AM_RCVG	0.46	1.01	0.18	0.40	0.00	0.00	0.02	0.05	0.02	0.05	0.02	0.04	8.5E-07	1.9E-06
45	Woodpile	WOOD_NEW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	3.41	4.97	0.0E+00	0.0E+00
46	*or New/Modified Units:*		*101.68*	*248.3*	*36.35*	*88.0*	*5.56*	*17.5*	*31.14*	*91.6*	*31.15*	*94.6*	*9.02*	*19.5*	*4.5E-03*	*6.9E-03*
47																

	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	Direct Process/Combustion Emissions													
2	CO		NOx		SO_2		PM2.5		PM10		VOC		Lead	
3	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
4														
5														
6	7.25	31.74	1.79	7.82	0.06	0.25	0.73	3.20	0.73	3.20	0.53	2.31	4.8E-05	2.1E-04
7	7.25	31.74	1.79	7.82	0.06	0.25	0.73	3.20	0.73	3.20	0.53	2.31	4.8E-05	2.1E-04
8	60.25	87.97	21.58	31.51	2.25	3.29	13.57	19.81	13.57	19.81	3.18	4.65	4.3E-03	6.3E-03
9	4.11	18.00	4.89	21.43	0.12	0.51	0.37	1.63	0.37	1.63	0.27	1.18	2.4E-05	1.1E-04
10	0.00	0.00	0.00	0.00	0.00	0.00	0.44	1.93	0.44	1.93	0.00	0.00	0.0E+00	0.0E+00
11	1.69	7.40	0.33	1.45	0.12	0.54	2.35	10.27	2.35	10.27	0.03	0.14	3.2E-06	1.4E-05
12	1.69	7.40	0.33	1.45	0.12	0.54	2.35	10.27	2.35	10.27	0.03	0.14	3.2E-06	1.4E-05
13	1.72	7.52	0.34	1.47	0.23	1.02	0.89	3.92	0.89	3.92	0.03	0.14	3.2E-06	1.4E-05
14	0.00	0.00	0.00	0.00	0.03	0.12	0.25	1.09	0.25	1.09	0.00	0.00	0.0E+00	0.0E+00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.19	0.04	0.19	0.00	0.00	0.0E+00	0.0E+00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.57	0.13	0.57	0.00	0.00	0.0E+00	0.0E+00
17	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.07	0.02	0.07	0.00	0.00	0.0E+00	0.0E+00
18	0.00	0.00	0.00	0.00	1.87	8.19	1.29	5.66	1.29	5.66	0.00	0.00	0.0E+00	0.0E+00
19	0.00	0.00	0.00	0.00	0.26	1.14	1.72	7.53	1.72	7.53	0.00	0.00	0.0E+00	0.0E+00
20	2.51	11.00	0.48	2.12	0.19	0.84	1.10	4.80	1.10	4.80	0.05	0.23	4.7E-06	2.1E-05
21	1.67	7.33	0.32	1.41	0.06	0.28	0.31	1.37	0.31	1.37	0.03	0.15	3.2E-06	1.4E-05
22	0.14	0.63	0.08	0.34	0.06	0.20	0.44	1.34	0.44	1.34	0.15	0.64	0.0E+00	0.0E+00
23	0.15	0.64	0.08	0.35	0.04	0.12	0.27	0.83	0.27	0.83	0.15	0.65	0.0E+00	0.0E+00
24	0.09	0.37	0.05	0.20	0.02	0.06	0.12	0.36	0.12	0.36	0.09	0.38	0.0E+00	0.0E+00
25	0.09	0.37	0.05	0.20	0.01	0.04	0.02	0.07	0.02	0.07	0.09	0.38	0.0E+00	0.0E+00
26	0.00	0.00	0.00	0.00	0.01	0.03	0.01	0.02	0.01	0.02	0.00	0.00	0.0E+00	0.0E+00
27	0.00	0.00	0.00	0.00	0.00	0.00	0.45	0.45	0.45	1.98	0.00	0.00	0.0E+00	0.0E+00
28	0.00	0.00	0.00	0.00	0.00	0.00	0.45	0.45	0.45	1.98	0.00	0.00	0.0E+00	0.0E+00
29	1.60	7.02	0.27	1.17	0.01	0.02	0.41	1.82	0.41	1.82	0.05	0.21	0.0E+00	0.0E+00
30	1.82	7.97	0.27	1.17	0.01	0.03	1.73	7.56	1.73	7.56	0.05	0.24	0.0E+00	0.0E+00
31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.01	0.00	0.00	0.0E+00	0.0E+00
32	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.21	0.05	0.21	0.00	0.00	0.0E+00	0.0E+00
33	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.21	0.05	0.21	0.00	0.00	0.0E+00	0.0E+00
34	0.00	0.00	0.00	0.00	0.00	0.00	0.24	1.06	0.24	1.06	0.00	0.00	0.0E+00	0.0E+00
35	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.21	0.05	0.21	0.00	0.00	0.0E+00	0.0E+00
36	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.21	0.05	0.21	0.00	0.00	0.0E+00	0.0E+00
37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.01	0.00	0.00	0.0E+00	0.0E+00
38	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.25	0.06	0.25	0.00	0.00	0.0E+00	0.0E+00
39														
40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0E+00	0.0E+00
41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0E+00	0.0E+00
42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0E+00	0.0E+00
43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0E+00	0.0E+00
44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0E+00	0.0E+00
45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	3.41	4.97	0.0E+00	0.0E+00
46														
47														

	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT
1							**Allocated AMU Combustion emissions**							
2														
3	**CO**		**NOx**		**SO_2**		**PM2.5**		**PM10**		**VOC**		**Lead**	
4	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
5														
6	0.126	0.275	0.103	0.226	0.001	0.002	0.013	0.028	0.013	0.028	0.010	0.021	4.5E-07	9.9E-07
7	0.126	0.275	0.103	0.226	0.001	0.002	0.013	0.028	0.013	0.028	0.010	0.021	4.5E-07	9.9E-07
8	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0E+00	0.0E+00
9	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0E+00	0.0E+00
10	0.145	0.317	0.047	0.103	0.000	0.001	0.006	0.012	0.006	0.012	0.004	0.009	2.0E-07	4.4E-07
11	0.481	1.053	0.156	0.342	0.001	0.003	0.019	0.041	0.019	0.041	0.014	0.031	6.6E-07	1.4E-06
12	0.477	1.044	0.155	0.339	0.001	0.003	0.018	0.040	0.018	0.040	0.014	0.031	6.6E-07	1.4E-06
13	0.348	0.763	0.113	0.248	0.001	0.002	0.013	0.029	0.013	0.029	0.010	0.022	4.8E-07	1.1E-06
14	0.059	0.129	0.019	0.042	0.000	0.000	0.002	0.005	0.002	0.005	0.002	0.004	8.1E-08	1.8E-07
15	0.046	0.101	0.015	0.033	0.000	0.000	0.002	0.004	0.002	0.004	0.001	0.003	6.4E-08	1.4E-07
16	0.038	0.083	0.012	0.027	0.000	0.000	0.001	0.003	0.001	0.003	0.001	0.002	5.2E-08	1.1E-07
17	0.020	0.043	0.006	0.014	0.000	0.000	0.001	0.002	0.001	0.002	0.001	0.001	2.7E-08	5.9E-08
18	0.190	0.417	0.062	0.135	0.001	0.001	0.007	0.016	0.007	0.016	0.006	0.012	2.6E-07	5.7E-07
19	0.504	1.103	0.164	0.358	0.002	0.003	0.019	0.043	0.019	0.043	0.015	0.033	6.9E-07	1.5E-06
20	0.296	0.649	0.096	0.211	0.001	0.002	0.011	0.025	0.011	0.025	0.009	0.019	4.1E-07	8.9E-07
21	0.440	0.963	0.143	0.312	0.001	0.003	0.017	0.037	0.017	0.037	0.013	0.028	6.1E-07	1.3E-06
22	0.125	0.273	0.041	0.089	0.000	0.001	0.005	0.011	0.005	0.011	0.004	0.008	1.7E-07	3.8E-07
23	0.027	0.059	0.009	0.019	0.000	0.000	0.001	0.002	0.001	0.002	0.001	0.002	3.7E-08	8.2E-08
24	0.044	0.096	0.014	0.031	0.000	0.000	0.002	0.004	0.002	0.004	0.001	0.003	6.0E-08	1.3E-07
25	0.055	0.121	0.018	0.039	0.000	0.000	0.002	0.005	0.002	0.005	0.002	0.004	7.6E-08	1.7E-07
26	0.120	0.264	0.039	0.086	0.000	0.001	0.005	0.010	0.005	0.010	0.004	0.008	1.7E-07	3.6E-07
27	0.330	0.723	0.271	0.594	0.003	0.006	0.033	0.073	0.033	0.073	0.025	0.056	1.2E-06	2.6E-06
28	0.330	0.723	0.271	0.594	0.003	0.006	0.033	0.073	0.033	0.073	0.025	0.056	1.2E-06	2.6E-06
29	0.342	0.749	0.111	0.243	0.001	0.002	0.013	0.029	0.013	0.029	0.010	0.022	4.7E-07	1.0E-06
30	0.342	0.749	0.111	0.243	0.001	0.002	0.013	0.029	0.013	0.029	0.010	0.022	4.7E-07	1.0E-06
31	0.022	0.049	0.007	0.016	0.000	0.000	0.001	0.002	0.001	0.002	0.001	0.001	3.1E-08	6.8E-08
32	0.016	0.035	0.005	0.011	0.000	0.000	0.001	0.001	0.001	0.001	0.000	0.001	2.2E-08	4.8E-08
33	0.042	0.092	0.014	0.030	0.000	0.000	0.002	0.004	0.002	0.004	0.001	0.003	5.8E-08	1.3E-07
34	0.012	0.027	0.004	0.009	0.000	0.000	0.000	0.001	0.000	0.001	0.000	0.001	1.7E-08	3.8E-08
35	0.013	0.028	0.004	0.009	0.000	0.000	0.000	0.001	0.000	0.001	0.000	0.001	1.7E-08	3.8E-08
36	0.010	0.021	0.003	0.007	0.000	0.000	0.000	0.001	0.000	0.001	0.000	0.001	1.3E-08	2.9E-08
37	0.007	0.016	0.002	0.005	0.000	0.000	0.000	0.001	0.000	0.001	0.000	0.000	1.0E-08	2.2E-08
38	0.014	0.030	0.005	0.010	0.000	0.000	0.001	0.001	0.001	0.001	0.000	0.001	1.9E-08	4.2E-08
39														
40	2.885	6.317	0.936	2.051	0.009	0.019	0.111	0.244	0.111	0.244	0.085	0.186	4.0E-06	8.7E-06
41	0.780	1.708	0.150	0.329	0.002	0.004	0.022	0.049	0.022	0.049	0.017	0.037	8.0E-07	1.7E-06
42	0.119	0.260	0.098	0.214	0.001	0.002	0.012	0.026	0.012	0.026	0.009	0.020	4.3E-07	9.3E-07
43	0.270	0.592	0.222	0.486	0.002	0.005	0.027	0.060	0.027	0.060	0.021	0.046	9.7E-07	2.1E-06
44	0.460	1.007	0.182	0.398	0.002	0.004	0.024	0.052	0.024	0.052	0.018	0.040	8.5E-07	1.9E-06
45														
46														
47														

	A	B	C	D	E	F
4	**Table 2**					
5	**Potential Criteria Air Pollutant Emissions from Boilers**					
6	**Pollutant**	**Emission Factor, lb/MMBtu**	**Operating Rate, MMBtu**		**Emission Rate***	
7			**Hourly**	**Annual**	**Hourly, lb/hr**	**ton/yr**
8	CO	0.074	98.0	858,480	7.25	31.74
9	NOx	0.018	98.0	858,480	1.79	7.82
10	SO2	0.00059	98.0	858,480	0.06	0.25
11	PM2.5	0.00745	98.0	858,480	0.73	3.20
12	PM10	0.00745	98.0	858,480	0.73	3.20
13	VOC	0.00539	98.0	858,480	0.53	2.31
14	Pb	4.90E-07	98.0	858,480	4.80E-05	2.10E-04
15	* Emissions rates are for each boiler.					

	A	B	C	D
1	**Flake Emission Factors**			
2	**Parameter**	**Value**	**Units**	**Basis**
3	Uncontrolled PM2.5/PM10			
4	Estimated PM emission rate, Gem flakers	0.73	lb/hr, bone dry solids	From Emissions Inventory in May 18, 2017 "Permit-to-Construct Modification Application" for Gem State Processing Heyburn. Emissions calculations based on June 20-21, 2011 stack test, as reported in application Emission Inventory..
5	operating rate, Gem State flakers, dry	2250	lb dry/hr	From May 18, 2017 "Permit-to-Construct Modification Application" for Gem State Processing Heyburn
6	flake moisture content	0.07		process knowledge
7	operating rate, Gem State flakers, actual	2,419	lb actual/hr	Based on 7% moisture content in finished product
8				
9	PM emission factor, actual product	0.302	lb/1000 lbs	Emission rate divided by actual operating rate.

	A	B	C	D	E	F	G	H	I	J	K	L
4	**Potential Criteria Air Pollutant Emissions from Flake Production***											
5	**Pollutant**	**Activity**	**Emission Factor**		**Operating Rate**			**Uncontrolled Emissions**		**Control**	**Controlled Emissions**	
6			**Value**	**Units**	**Hourly**	**Annual**	**Units**	**lb/hr**	**ton/yr**	**Efficiency**	**lb/hr**	**ton/yr**
7	PM2.5	Dehydration†	0.302	lb/1000 lbs	12	105,120	1000 lbs	3.62	15.9	75%	0.91	4.0
8	PM10	Dehydration†	0.302	lb/1000 lbs	12	105,120	1000 lbs	3.62	15.9	75%	0.91	4.0
9	* Total for Flaker Production. Emissions from each stack are 50% of total emissions.											
10	† Based on 12,000 lb/hr production (4 drums @ 3000 lb/hr per drum).											
11												
12												

	A	B	C	D
1	**CALCULATED PARAMETERS - BELT DRYER EMISSION FACTORS**			
2	**Parameter**	**Value**	**Units**	**Basis**
3				
4	**Dehydration PM Emission Factors**			
5	Stage A Exhaust			
6	inlet moisture	81.5%		
7	outlet moisture	60.0%		
8	% of drying occurring in stage	28.7%		
9	cumulative % of drying completed at start of stage	0.0%		
10	cumulative % of drying completed at end of stage	28.7%		
11	*Filterable PM $_{10}$*			
12	cumulative % of filt PM_{10} emitted at start of stage	0.0%		
13	cumulative % of filt PM_{10} emitted by end of stage	10.6%		
14	Filterable PM_{10} increment in stage	10.6%		
15	Filterable PM_{10} emission factor for stage	0.074	lb/1000 lb	
16	*Condensible PM10*			
17	cumulative % of cndnsbl PM_{10} emitted at start of stage	0.0%		
18	cumulative % of cndnsbl PM_{10} emitted by end of stage	33.5%		
19	cndnsbl PM_{10} increment in stage	33.5%		
20	cndnsbl PM_{10} emission factor for stage	0.101	lb/1000 lb	
21	Total PM10 emissions for Stage A Exhaust	0.174	lb/1000 lb	
22	Stage BCD Exhaust			
23	inlet moisture	60.0%		
24	outlet moisture	6.5%		
25	% of drying occurring in stage	71.3%		
26	cumulative % of drying completed at start of stage	28.7%		
27	cumulative % of drying completed at end of stage	100.0%		
28	Filterable PM10			
29	cumulative % of filt PM_{10} emitted at start of stage	10.6%		
30	cumulative % of filt PM_{10} emitted by end of stage	100.0%		
31	Filterable PM10 increment in stage	89.4%		
32	Filterable PM10 emission factor for stage	0.626	lb/1000 lb	
33	Condensible PM10			
34	cumulative % of cndnsbl PM_{10} emitted at start of stage	33.5%		
35	cumulative % of cndnsbl PM_{10} emitted by end of stage	100.0%		
36	cndnsbl PM10 increment in stage	66.5%		
37	cndnsbl PM10 emission factor for stage	0.199	lb/1000 lb	
38	Total PM10 emissions for Stage BCD Exhaust	0.826	lb/1000 lb	
39	**Combustion Emission Factors**			

	A	B	C	D
1	**CALCULATED PARAMETERS - BELT DRYER EMISSION FACTORS**			
2	**Parameter**	**Value**	**Units**	**Basis**
40	*NOx Emissions Winnox 0200*			
41	PPM, stack gas concentration	25	ppmv at 3% oxygen	vendor guarantee
42	FW, formula weight	46	-	NOx as NO2
43	E, emissions	0.00000299	lb/dscf	=PPM*FW/(385.1*10^6)
44	Fa, Fd adjusted to 3% O2	10,170	dscf/MMBtu @ 3% O2	=Fd*(20.9/(20.9-3))
45	heat rate emission factor	0.030	lb/MMBtu	=E*Fa
46	fuel rate emission factor	30.98	lb/MMscf NG	
47	Winnox 0100 emissions			
48	PPM, stack gas concentration	10	ppmv at 3% oxygen	vendor guarantee
49	FW, formula weight	46	-	NOx as NO2
50	E, emissions	0.00000119	lb/dscf	=PPM*FW/(385.1*10^6)
51	Fa, Fd adjusted to 3% O2	10,170	dscf/MMBtu @ 3% O2	=Fd*(20.9/(20.9-3))
52	heat rate emission factor	0.012	lb/MMBtu	=E*Fa
53	fuel rate emission factor	12.39	lb/MMscf NG	
54	*CO Emissions*			
55	fuel rate emission factor	84	lb/MMscf	AP-42, Section 1.4 (7/98).for small boilers < 100 MMBtu
56	heat rate emission factor	0.18200	lb/MMBtu	lb/MMscf ÷ HHV NG
57	*PM2.5 Emissions*			Use CO EF of 0.182 lb/MMBtu from November 2011 source test report Table 7 instead of CO EF of 84 lb/MMscf or 0.08235 lb/MMBtu from AP-42.
58	fuel rate emission factor	7.6	lb/MMscf	AP-42, Section 1.4 (7/98).for small boilers < 100 MMBtu. All PM counted as PM2.5
59	heat rate emission factor	0.00745	lb/MMBtu	lb/MMscf ÷ HHV NG
60	*PM10 Emissions*			
61	fuel rate emission factor	7.6	lb/MMscf	AP-42, Section 1.4 (7/98).for small boilers < 100 MMBtu. All PM counted as PM10
62	heat rate emission factor	0.00745	lb/MMBtu	lb/MMscf ÷ HHV NG
63	*SO_2* Emissions			
64	fuel rate emission factor	0.6	lb/MMscf	AP-42, Section 1.4 (7/98).for small boilers < 100 MMBtu
65	heat rate emission factor	0.00059	lb/MMBtu	lb/MMscf ÷ HHV NG
66	*VOC Emissions*			
67	fuel rate emission factor	5.5	lb/MMscf	AP-42, Section 1.4 (7/98).for small boilers < 100 MMBtu
68	heat rate emission factor	0.00539	lb/MMBtu	lb/MMscf ÷ HHV NG
69	*Pb Emissions*			
70	fuel rate emission factor	0.0005	lb/MMscf	AP-42, Section 1.4 (7/98).for small boilers < 100 MMBtu
71	heat rate emission factor	4.90E-07	lb/MMBtu	lb/MMscf ÷ HHV NG

	A	B	C	D	E	F	G	H	I	J
4	**Potential Criteria Air Pollutant Emissions from P4 Dehydration**									
5	**Dryer**	**Pollutant**	**Activity**	**Emission Factor**		**Operating Rate**			**Potential Emissions**	
6	**Stage**			**Value**	**Units**	**Hourly**	**Annual**	**Units**	**Hourly, lb/hr**	**ton/yr**
7	Stage A	CO	NG combustion	0.182	lb/MMBtu	8.8	77,088	MMBtu	1.602	7.015
8		NOx	NG combustion†	0.030	lb/MMBtu	8.8	77,088	MMBtu	0.267	1.171
9		SO2	NG combustion	0.0006	lb/MMBtu	8.8	77,088	MMBtu	0.005	0.023
10		PM2.5	Dehydration*	0.174	lb/1000 lb	2.0	17,520	1000 lbs	0.349	1.528
11			NG combustion	0.0075	lb/MMBtu	8.8	77,088	MMBtu	0.066	0.287
12								*Total PM2.5*	0.415	1.816
13		PM10	Dehydration*	0.174	lb/1000 lb	2.0	17,520	1000 lbs	0.349	1.528
14			NG combustion	0.0075	lb/MMBtu	8.8	77,088	MMBtu	0.066	0.287
15								*Total PM10*	0.415	1.816
16		VOC	NG combustion	0.0054	lb/MMBtu	8.8	77,088	MMBtu	0.047	0.208
17		Pb	NG combustion	4.90E-07	lb/MMBtu	8.8	77,088	MMBtu	4.31E-06	1.89E-05
18	Stage B	CO	NG combustion	0.182	lb/MMBtu	10	87,600	MMBtu	1.820	7.972
19		NOx	NG combustion†	0.030	lb/MMBtu	8	70,080	MMBtu	0.243	1.064
20			NG combustion‡	0.012	lb/MMBtu	2	17,520	MMBtu	0.024	0.106
21								*Total NOx*	0.267	1.171
22		SO2	NG combustion	0.0006	lb/MMBtu	10	87,600	MMBtu	0.006	0.026
23		PM2.5	Dehydration*	0.826	lb/1000 lb	2.0	17,520	1000 lbs	1.651	7.232
24			NG combustion	0.0075	lb/MMBtu	10	87,600	MMBtu	0.075	0.326
25								*Total PM2.5*	1.726	7.558
26		PM10	Dehydration*	0.826	lb/1000 lb	2.0	17,520	1000 lbs	1.651	7.232
27			NG combustion	0.0075	lb/MMBtu	10	87,600	MMBtu	0.075	0.326
28								*Total PM10*	1.726	7.558
29		VOC	NG combustion	0.0054	lb/MMBtu	10	87,600	MMBtu	0.054	0.236
30		Pb	NG combustion	4.90E-07	lb/MMBtu	10	87,600	MMBtu	4.90E-06	2.15E-05
31	† Winnox 0200 burner									
32	‡ Winnox 0100 burner									
33										

	A	B	C	D	E	F
5	**Potential Criteria Air Pollutant Emissions from Kipper Boiler Post-Project**					
6	**Pollutant**	**Emission Factor*, lb/MMBtu**	**Operating Rate, MMBtu**		**Emission Rate***	
7			**Hourly**	**Annual**	**Hourly, lb/hr**	**ton/yr**
8	CO	0.669	90.0	262,800	60.25	87.97
9	NOx	0.240	90.0	262,800	21.58	31.51
10	SO2	0.025	90.0	262,800	2.25	3.29
11	PM2.5	0.151	90.0	262,800	13.57	19.81
12	PM10	0.151	90.0	262,800	13.57	19.81
13	VOC	0.035	90.0	262,800	3.18	4.65
14	Pb	4.80E-05	90.0	262,800	4.32E-03	6.31E-03
15	* Based on wood-only firing					

	A	B	C
1	**POTENTIAL INCREASE IN KIPPER BOILER EMISSIONS DUE TO PROCESS A PRODUCTION INCREASE**		
2	**Constitutent**	**Emission Factor, lb/MMBtu**	**Emissions, lb/hr @ 1.052 MMBtuh**
3	SO2	0.025	0.026307739
4	NOx	0.240	0.252
5	CO	0.669	0.705
6	PM	0.154	0.162
7	PM10	0.151	0.159
8	PM2.5	0.151	0.159
9	VOC	0.035	0.037
10	Lead	4.80E-05	5.05E-05
11	Acenaphthene	9.10E-07	9.58E-07
12	Acenaphthylene	5.00E-06	5.26E-06
13	Acetaldehyde	8.30E-04	8.73E-04
14	Acetone	1.90E-04	2.00E-04
15	Acetophenone	3.20E-09	3.37E-09
16	Acrolein	4.00E-03	4.21E-03
17	Anthracene	3.00E-06	3.16E-06
18	Benzaldehyde	8.50E-07	8.94E-07
19	Benzene	4.20E-03	4.42E-03
20	Benzo(a)anthracene	6.50E-08	6.84E-08
21	Benzo(a)pyrene	2.60E-06	2.74E-06
22	Benzo(b)fluoranthene	1.00E-07	1.05E-07
23	Benzo(e)pyrene	2.60E-09	2.74E-09
24	Benzo(g,h,i)perylene	9.30E-08	9.79E-08
25	Benzo(j,k)fluoranthene	1.60E-07	1.68E-07
26	Benzo(k)fluoranthene	3.60E-08	3.79E-08
27	Benzoic acid	4.70E-08	4.95E-08
28	bis(2-Ethylhexyl)phthalate	4.70E-08	4.95E-08
29	Bromomethane	1.50E-05	1.58E-05
30	2-Butanone (MEK)	5.40E-06	5.68E-06
31	Carbazole	1.80E-06	1.89E-06
32	Carbon tetrachloride	4.50E-05	4.74E-05
33	Chlorine	7.90E-04	8.31E-04
34	Chlorobenzene	3.30E-05	3.47E-05
35	Chloroform	2.80E-05	2.95E-05
36	Chloromethane	2.30E-05	2.42E-05
37	2-Chloronaphthalene	2.40E-09	2.53E-09
38	2-Chlorophenol	2.40E-08	2.53E-08

	A	B	C
2	**Constitutent**	**Emission Factor, lb/MMBtu**	**Emissions, lb/hr @ 1.052 MMBtuh**
39	Chrysene	3.80E-08	4.00E-08
40	Crotonaldehyde	9.90E-06	1.04E-05
41	Decachlorobiphenyl	2.70E-10	2.84E-10
42	Dibenzo(a,h)anthracene	9.10E-09	9.58E-09
43	1,2-Dibromoethene	5.50E-05	5.79E-05
44	Dichlorobiphenyl	7.40E-10	7.79E-10
45	1,2-Dichloroethane	2.90E-05	3.05E-05
46	Dichloromethane	2.90E-04	3.05E-04
47	1,2-Dichloropropane	3.30E-05	3.47E-05
48	2,4-Dinitrophenol	1.80E-07	1.89E-07
49	Ethylbenzene	3.10E-05	3.26E-05
50	Fluoranthene	1.60E-06	1.68E-06
51	Fluorene	3.40E-06	3.58E-06
52	Formaldehyde	4.40E-03	4.63E-03
53	Heptachlorobiphenyl	6.60E-11	6.95E-11
54	Hexachlorobiphenyl	5.50E-10	5.79E-10
55	Hexanal	7.00E-06	7.37E-06
56	Hexane	0.00E+00	0.00E+00
57	Heptachlorodibenzo-p-dioxins	2.00E-09	2.10E-09
58	Heptachlorodibenzo-p-furans	2.40E-10	2.53E-10
59	Hexachlorodibenzo-p-dioxins	1.60E-06	1.68E-06
60	Hexachlorodibenzo-p-furans	2.80E-10	2.95E-10
61	HCl	1.90E-02	2.00E-02
62	Indeno(1,2,3,c,d)pyrene	8.70E-08	9.16E-08
63	Isobutyraldehyde	1.20E-05	1.26E-05
64	Methane	2.10E-02	2.21E-02
65	2-Methylnaphthalene	1.60E-07	1.68E-07
66	Monochlorobiphenyl	2.20E-10	2.32E-10
67	Naphthalene	9.70E-05	1.02E-04
68	2-Nitrophenol	2.40E-07	2.53E-07
69	4-Nitrophenol	1.10E-07	1.16E-07
70	Octachlorodibenzo-p-dioxins	6.60E-08	6.95E-08
71	Octachlorodibenzo-p-furans	8.80E-11	9.26E-11
72	Pentachlorodibenzo-p-dioxins	1.50E-09	1.58E-09
73	Pentachlorodibenzo-p-furans	4.20E-10	4.42E-10
74	Pentachlorobiphenyl	1.20E-09	1.26E-09
75	Pentachlorophenol	5.10E-08	5.37E-08
76	Perylene	5.20E-10	5.47E-10
77	Phenanthrene	7.00E-06	7.37E-06

	A	B	C
2	**Constitutent**	**Emission Factor, lb/MMBtu**	**Emissions, lb/hr @ 1.052 MMBtuh**
78	Phenol	5.10E-05	5.37E-05
79	Phosphorus	2.70E-05	2.84E-05
80	Propanal	3.20E-06	3.37E-06
81	Propionaldehyde	6.10E-05	6.42E-05
82	Pyrene	3.70E-06	3.89E-06
83	Styrene	1.90E-03	2.00E-03
84	2,3,7,8-Tetrachlorodibenzo-p-dioxins	8.60E-12	9.05E-12
85	Tetrachlorodibenzo-p-dioxins	4.70E-10	4.95E-10
86	2,3,7,8-Tetrachlorodibenzo-p-furans	9.00E-11	9.47E-11
87	Tetrachlorodibenzo-p-furans	7.50E-10	7.89E-10
88	Tetrachlorobiphenyl	2.50E-09	2.63E-09
89	Tetrachloroethene	3.80E-05	4.00E-05
90	o-Tolualdehyde	7.20E-06	7.58E-06
91	p-Tolualdehyde	1.10E-05	1.16E-05
92	Toluene	9.20E-04	9.68E-04
93	Trichlorobiphenyl	2.60E-09	2.74E-09
94	1,1,1-Trichloroethane	3.10E-05	3.26E-05
95	Trichloroethene	3.00E-05	3.16E-05
96	Trichlorofluoromethane	4.00E-05	4.21E-05
97	2,4,6-Trichlorophenol	2.20E-08	2.32E-08
98	Vinyl Chloride	1.80E-05	1.89E-05
99	o-Xylene	2.50E-05	2.63E-05
100	Antimony	7.90E-06	8.31E-06
101	Arsenic	2.20E-05	2.32E-05
102	Barium	1.70E-04	1.79E-04
103	Beryllium	1.10E-06	1.16E-06
104	Cadmium	4.10E-06	4.31E-06
105	Chromium, total	2.10E-05	2.21E-05
106	Chromium, hexavalent	3.50E-06	3.68E-06
107	Cobalt	6.50E-06	6.84E-06
108	Copper	4.90E-05	5.16E-05
109	Iron	9.90E-04	1.04E-03
110	Lead	4.80E-05	5.05E-05
111	Manganese	1.60E-03	1.68E-03
112	Mercury	3.50E-06	3.68E-06
113	Molybdenum	2.10E-06	2.21E-06
114	Nickel	3.30E-05	3.47E-05

	A	B	C
2	**Constitutent**	**Emission Factor, lb/MMBtu**	**Emissions, lb/hr @ 1.052 MMBtuh**
115	Potassium	3.90E-02	4.10E-02
116	Selenium	2.80E-06	2.95E-06
117	Silver	1.70E-03	1.79E-03
118	Sodium	3.60E-04	3.79E-04
119	Strontium	1.00E-05	1.05E-05
120	Tin	2.30E-05	2.42E-05
121	Titanium	2.00E-05	2.10E-05
122	Vanadium	9.80E-07	1.03E-06
123	Yttrium	3.00E-07	3.16E-07
124	Zinc	4.20E-04	4.42E-04

	A	B	C
1	**WOODPILE EMISSION CALCULATIONS**		
2	**Parameter**	**Value**	**Units**
3	PM10 emission factor	0.00114	lb/ton of wood handled
4	PM2.5 emission factor	0.00017	lb/ton of wood handled
5	VOC emission factor	0.53	lb/ton of wood handled
6	heat content of wood	7,000	Btu/lb
7	heat input from wood		
8	hourly	90	MMBtuh
9	annual	262,800	MMBtu/yr
10	tons of wood handled		
11	hourly	6.43	tons/hr
12	annual	18,771	ton/yr
13	PM10 emissions		
14	hourly	0.007	lb/hr
15	annual	0.011	ton/yr
16	PM2.5 emissions		
17	hourly	0.0011	lb/hr
18	annual	0.0016	ton/yr
19	VOC emissions		
20	hourly	3.41	lb/hr
21	annual	4.97	ton/yr
22			
23	Existing woodpile emissions		
24	PM10 emissions		
25	hourly	0.007	lb/hr
26	annual	0.032	ton/yr
27	PM2.5 emissions		
28	hourly	0.0011	lb/hr
29	annual	0.005	ton/yr
30	VOC emissions		
31	hourly	3.41	lb/hr
32	annual	14.92	ton/yr
33			
34			
35			
36			
37			

	A	E	F	G	H	I	J	K	L
3	**TAP EMISSIONS**								
4			**Emission Factor, lb/MMBtu**	**Boilers 1A and 2A @ 98 MMBtu each boiler.**		**Replacement Belt Dryer @ 18.8 MMBtuh**		**New Air Make-up Units @ 19.59 MMBtuh**	
5	**Air Pollutant**	**SEL, lb/hr**		**Emission Rate, lb/hr***	**% of SEL**	**Emission Rate, lb/hr***	**% of SEL**	**Emission Rate, lb/hr***	**% of SEL**
6	PAH (Idaho)	9.10E-05	6.73E-07	6.60E-05	NA†	1.27E-05	14%	1.32E-05	14%
7	POM (Idaho)	2.00E-06	1.12E-08	1.10E-06	NA†	2.10E-07	11%	2.19E-07	11%
8	Benzene	8.00E-04	2.06E-06	2.02E-04	NA†	3.87E-05	5%	4.03E-05	5%
9	Dichlorobenzene	2.00E+01	1.18E-06	1.15E-04	NA†	2.21E-05	0%	2.30E-05	0%
10	Formaldehyde	5.10E-04	7.35E-05	7.21E-03	NA†	1.38E-03	271%	1.44E-03	282%
11	Hexane	1.20E+01	1.76E-03	1.73E-01	NA†	3.32E-02	0%	3.46E-02	0%
12	Pentane	1.18E+02	2.55E-03	2.50E-01	0.2%	4.79E-02	0%	4.99E-02	0%
13	Toluene	2.50E+01	3.33E-06	3.27E-04	NA†	6.27E-05	0%	6.53E-05	0%
14	Arsenic	1.50E-06	1.96E-07	1.92E-05	NA†	3.68E-06	246%	3.84E-06	256%
15	Beryllium	2.80E-05	1.18E-08	1.16E-06	NA†	2.22E-07	1%	2.31E-07	1%
16	Cadmium	3.70E-06	1.08E-06	1.06E-04	NA†	2.03E-05	549%	2.12E-05	572%
17	Chromium	3.30E-02	1.37E-06	1.34E-04	NA†	2.58E-05	0%	2.68E-05	0%
18	Chromium(VI)	5.60E-07	6.85E-08	6.71E-06	NA†	1.29E-06	230%	1.34E-06	240%
19	Cobalt	3.30E-03	8.24E-08	8.08E-06	NA†	1.55E-06	0%	1.61E-06	0%
20	Manganese	3.33E-01	3.73E-07	3.66E-05	NA†	7.01E-06	0%	7.31E-06	0%
21	Nickel	2.70E-05	2.06E-06	2.02E-04	NA†	3.87E-05	143%	4.03E-05	149%
22	Selenium	1.30E-02	2.35E-08	2.30E-06	NA†	4.42E-07	0%	4.60E-07	0%
23	Nitrous Oxide	6.00E+00	2.16E-03	2.11E-01	3.5%	4.05E-02	1%	4.22E-02	1%
24	**EPA Total HAPs**	-	1.85E-03	1.81E-01		3.48E-02		3.63E-02	
25	* Emissions data are per boiler.								
26	† TAP analysis not needed because ambient impacts of TAP addressed in 40 CFR 63, Subparts JJJJJJ.								
27									

	A	B	C	D
1				
2	**Parameter**	**Value**	**Units**	**Discussion**
3	Dryer heat supply requirement	4.8	MMBtu/ton produced	see inputs
4	Granules production increase	3.800	ton/day	see inputs
5	Potential Increase in NG Usage			
6	Increased dryer heat required for production increase	0.76	MMBtu/hr	
7		6,658	MMBtu/yr	
8	Potential Increase in Kipper Boiler Firing			
9	Heat provided by steam	1,000	Btu/lb of steam	
10	Kipper Boiler efficiency	72.2%	Btu steam/Btu fuel	
11	Kipper fuel input per lb of steam	1,385	Btu fuel/lb of steam	
12	Added steam required by production increase	760	lb steam/hr	
13		6,657,600	lb steam/yr	
14	Increased Kipper Boiler firing required by production increase	1.052	MMBtu/hr	
15		9,218	MMBtu/yr	

	A	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
1			**Annual TAP Emissions, lb/hr**															
2	Release Point	Source ID	**Formaldehyde**			**Arsenic**			**Cadmium**			**Chromium(VI)**			**Nickel**			
3			Process	AMU	Total	Process	AMU	Total	Process	AMU	Total	Process	AMU	Total	Process	AMU	Total	
4	Boiler 1A*	BLR1A	-	6.2E-05	6.2E-05	-	1.7E-07	1.7E-07	-	9.2E-07	9.2E-07	-	5.8E-08	5.8E-08	-	1.7E-06	1.7E-06	
5	Boiler 2A*	BLR2A	-	6.2E-05	6.2E-05	-	1.7E-07	1.7E-07	-	9.2E-07	9.2E-07	-	5.8E-08	5.8E-08	-	1.7E-06	1.7E-06	
6	P4A†	P4A	6.5E-04	-	6.5E-04	1.7E-06	-	1.7E-06	9.5E-06	-	9.5E-06	6.0E-07	-	6.0E-07	1.8E-05	-	1.8E-05	
7	P4BCD†	P4BCD	7.4E-04	-	7.4E-04	2.0E-06	-	2.0E-06	1.1E-05	-	1.1E-05	6.9E-07	-	6.9E-07	2.1E-05	-	2.1E-05	
8	Flake North‡	FLK_N	-	1.6E-04	1.6E-04	-	4.4E-07	4.4E-07	-	2.4E-06	2.4E-06	-	1.5E-07	1.5E-07	-	4.6E-06	4.6E-06	
9	Flake South‡	FLK_S	-	1.6E-04	1.6E-04	-	4.4E-07	4.4E-07	-	2.4E-06	2.4E-06	-	1.5E-07	1.5E-07	-	4.6E-06	4.6E-06	
10	New Boilerhouse	AM_BLRNEW	-	5.9E-05	5.9E-05	-	1.6E-07	1.6E-07	-	8.7E-07	8.7E-07	-	5.5E-08	5.5E-08	-	1.7E-06	1.7E-06	
11	Flake	AM_FLAKE	-	1.3E-04	1.3E-04	-	3.6E-07	3.6E-07	-	2.0E-06	2.0E-06	-	1.3E-07	1.3E-07	-	3.8E-06	3.8E-06	
12	Receiving	AM_RECG	-	1.2E-04	1.2E-04	-	3.1E-07	3.1E-07	-	1.7E-06	1.7E-06	-	1.1E-07	1.1E-07	-	3.3E-06	3.3E-06	
13	Notes: * Boiler emissions of TAPs in this table are addressed separetely under 40 CFR 62, Subpart JJJJJJ. See discussion in Section 2.1.4. † No emissions from new or modified AMUs exhaust via this release point. ‡ The Flake operations do not include any fuel combustion. The only TAP emissions from this starck are from Flake building AMUs.																	

	T	U	V	W	X	Y	Z
1			**TAPs for paste into BEEST. Emission rates multiplied**				
2			**by 10^6**				
3			HCOH	As	Cd	Cr+6	Ni
4		Boiler 1A	62.40	0.166	0.915	0.058	1.747
5		Boiler 2A	62.40	0.166	0.915	0.058	1.747
6		P4A	647.06	1.725	9.504	0.603	18.128
7		P4BCD	735.29	1.960	10.800	0.685	20.600
8		Flake North	164.13	0.438	2.407	0.153	4.596
9		Flake South	164.13	0.438	2.407	0.153	4.596
10		New Boilerhouse	59.02	0.157	0.866	0.055	1.653
11		Flake	134.39	0.358	1.971	0.125	3.763
12		Receiving	117.72	0.314	1.727	0.110	3.296
13							

project emissions increase

Process	Stack	Process Emissions												Combustion Emissions - Process Burners																										
					PM10			PM2.5			SO_2					PM10			PM2.5			SO2			NOx			CO			VOC					
		Unit Process Throughput Increase[a]			Emission Factor, lb/1000 lbs	Emissions Increase		Emission Factor, lb/1000 lbs	Emissions Increase		Emission Factor, lb/1000 lbs	Emissions Increase		Burner Capacity, MMBtuh	Combustion Rate Increase, MMBtu		Emission Factor, lb/MMBtu	Emissions Increase		Emission Factor, lb/MMBtu	Emissions Increase		Emission Factor, lb/MMBtu	Emissions Increase		Emission Factor, lb/MMBtu	Emissions Increase		Emission Factor, lb/MMBtu	Emissions Increase		Emission Factor, lb/MMBtu	Emissions Increase			
		ton/day	lb/hr	ton/yr	lbs	lb/hr	ton/yr	lbs	lb/hr	ton/yr	lbs	lb/hr	ton/yr	MMBtuh	Hourly	Annual	lb/MMBtu	lb/hr	ton/yr	lb/MMBtu	lb/hr	ton/yr	lb/MMBtu	lb/hr	ton/yr	lb/MMBtu	lb/hr	ton/yr	lb/MMBtu	lb/hr	ton/yr	lb/MMBtu	lb/hr	ton/yr			
Process A	7020	30	2,533	11,096	0.010	0.026	0.11	0.010	0.026	0.11	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	7101	15	1,267	5,548	0.106	0.134	0.59	0.106	0.134	0.59	0.005	0.006	0.03	6.5	0.25	2,208	0.007	0.002	0.01	0.007	0.002	0.01	0.002	0.001	0.00	0.051	0.013	0.06	0.260	0.066	0.29	0.005	0.001	0.01			
	7102	15	1,267	5,548	0.106	0.134	0.59	0.106	0.134	0.59	0.005	0.006	0.03	6.5	0.25	2,208	0.007	0.002	0.01	0.007	0.002	0.01	0.002	0.001	0.00	0.051	0.013	0.06	0.260	0.066	0.29	0.005	0.001	0.01			
	7019	30	2,533	11,096	0.020	0.049	0.22	0.020	0.049	0.22	0.005	0.013	0.06	6.6	0.26	2,242	0.007	0.002	0.01	0.007	0.002	0.01	0.002	0.001	0.00	0.051	0.013	0.06	0.260	0.067	0.29	0.005	0.001	0.01			
	7001	4	317	1,387	0.046	0.015	0.06	0.046	0.015	0.06	0.005	0.002	0.01		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	7027	4	317	1,387	0.008	0.003	0.01	0.008	0.003	0.01	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	7006	30	2,533	11,096	0.003	0.008	0.03	0.003	0.008	0.03	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
Process B	8	4	317	1,387	0.002	0.001	0.00	0.002	0.001	0.00	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	5001	4	317	1,387	0.008	0.003	0.01	0.008	0.003	0.01	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	5000	4	317	1,387	0.002	0.001	0.00	0.002	0.001	0.00	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	432	4	317	1,387	0.002	0.001	0.00	0.002	0.001	0.00	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	322	0.04	3	14	0.008	0.000	0.00	0.008	0.000	0.00	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	572	0.19	16	69	0.038	0.001	0.00	0.038	0.001	0.00	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			

Notes:

line. Inside the mixback loop, the throughput rates are about eight times larger than the net process production rate. Stacks 7101 and 7102 operate in parallel, so the loading rate for those dryers is four times the process production rate. For stacks 7020, 7019, and 7006, the loading rates are eight times the production line throughput. Stacks 7001 and 7027 are located after

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37

total emissions - post project

Process	Stack	Process Emissions												Combustion Emissions - Process Burners																										
					PM10			PM2.5			SO_2					PM10			PM2.5			SO2			NOx			CO			VOC			Lead		
		Unit Process Throughput Increase[a]			Emission Factor, lb/1000 lbs	Emissions Increase		Emission Factor, lb/1000 lbs	Emissions Increase		Emission Factor, lb/1000 lbs	Emissions Increase		Burner Capacity, MMBtuh	Combustion Rate Increase, MMBtu		Emission Factor, lb/MMBtu	Emissions Increase		Emission Factor, lb/MMBtu	Emissions Increase		Emission Factor, lb/MMBtu	Emissions Increase		Emission Factor, lb/MMBtu	Emissions Increase		Emission Factor, lb/MMBtu	Emissions Increase		Emission Factor, lb/MMBtu	Emissions Increase		Emissions Increase	
		ton/day	lb/hr	ton/yr	lbs	lb/hr	ton/yr	lbs	lb/hr	ton/yr	lbs	lb/hr	ton/yr	MMBtuh	Hourly	Annual	lb/MMBtu	lb/hr	ton/yr	lb/MMBtu	lb/hr	ton/yr	lb/MMBtu	lb/hr	ton/yr	lb/MMBtu	lb/hr	ton/yr	lb/MMBtu	lb/hr	ton/yr	lb/MMBtu	lb/hr	ton/yr	lb/MMBtu	lb/hr	ton/yr
Process A	7020	520	43,333	189,800	0.010	0.441	1.93	0.010	0.441	1.93	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	7101	260	21,667	94,900	0.106	2.297	10.06	0.106	2.297	10.06	0.005	0.108	0.47	6.5	6.50	56,940	0.007	0.048	0.21	0.007	0.048	0.21	0.002	0.015	0.07	0.051	0.332	1.45	0.260	1.690	7.40	0.005	0.033	0.14	4.9E-07	3.2E-06	1.4E-05
	7102	260	21,667	94,900	0.106	2.297	10.06	0.106	2.297	10.06	0.005	0.108	0.47	6.5	6.50	56,940	0.007	0.048	0.21	0.007	0.048	0.21	0.002	0.015	0.07	0.051	0.332	1.45	0.260	1.690	7.40	0.005	0.033	0.14	4.9E-07	3.2E-06	1.4E-05
	7019	520	43,333	189,800	0.020	0.845	3.70	0.020	0.845	3.70	0.005	0.217	0.95	6.6	6.60	57,816	0.007	0.049	0.22	0.007	0.049	0.22	0.002	0.016	0.07	0.051	0.337	1.47	0.260	1.716	7.52	0.005	0.033	0.14	4.9E-07	3.2E-06	1.4E-05
	7001	65	5,417	23,725	0.046	0.249	1.09	0.046	0.249	1.09	0.005	0.027	0.12		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	7027	65	5,417	23,725	0.008	0.043	0.19	0.008	0.043	0.19	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	7006	520	43,333	189,800	0.003	0.130	0.57	0.003	0.130	0.57	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process B	8	363	30,217	132,349	0.002	0.048	0.21	0.002	0.048	0.21	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	5001	363	30,217	132,349	0.008	0.242	1.06	0.008	0.242	1.06	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	5000	363	30,217	132,349	0.002	0.048	0.21	0.002	0.048	0.21	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	432	363	30,217	132,349	0.002	0.048	0.21	0.002	0.048	0.21	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	322	3.63	302	1,323	0.008	0.002	0.01	0.008	0.002	0.01	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	572	18.13	1,511	6,617	0.038	0.057	0.25	0.038	0.057	0.25	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Notes:

line. Inside the mixback loop, the throughput rates are about eight times larger than the net process production rate. Stacks 7101 and 7102 operate in parallel, so the loading rate for those dryers is four times the process production rate. For stacks 7020, 7019, and 7006, the loading rates are eight times the production line throughput. Stacks 7001 and 7027 are located after

total emissions - pre-project

Process	Stack	Process Emissions												Combustion Emissions - Process Burners																										
					PM10			PM2.5			SO_2					PM10			PM2.5			SO2			NOx			CO			VOC					
		Unit Process Throughput Increase[a]			Emission Factor, lb/1000 lbs	Emissions		Emission Factor, lb/1000 lbs	Emissions		Emission Factor, lb/1000 lbs	Emissions		Burner Capacity, MMBtuh	Combustion Rate Increase, MMBtu		Emission Factor, lb/MMBtu	Emissions		Emission Factor, lb/MMBtu	Emissions		Emission Factor, lb/MMBtu	Emissions		Emission Factor, lb/MMBtu	Emissions		Emission Factor, lb/MMBtu	Emissions		Emission Factor, lb/MMBtu	Emissions			
		ton/day	lb/hr	ton/yr	lbs	lb/hr	ton/yr	lbs	lb/hr	ton/yr	lbs	lb/hr	ton/yr	MMBtuh	Hourly	Annual	lb/MMBtu	lb/hr	ton/yr	lb/MMBtu	lb/hr	ton/yr	lb/MMBtu	lb/hr	ton/yr	lb/MMBtu	lb/hr	ton/yr	lb/MMBtu	lb/hr	ton/yr	lb/MMBtu	lb/hr	ton/yr			
Process A	7020	490	40,800	178,704	0.010	0.415	1.82	0.010	0.415	1.82	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	7101	245	20,400	89,352	0.106	2.162	9.47	0.106	2.162	9.47	0.005	0.102	0.45	6.5	6.50	56,940	0.007	0.048	0.21	0.007	0.048	0.21	0.002	0.015	0.07	0.051	0.332	1.45	0.260	1.690	7.40	0.005	0.033	0.14			
	7102	245	20,400	89,352	0.106	2.162	9.47	0.106	2.162	9.47	0.005	0.102	0.45	6.5	6.50	56,940	0.007	0.048	0.21	0.007	0.048	0.21	0.002	0.015	0.07	0.051	0.332	1.45	0.260	1.690	7.40	0.005	0.033	0.14			
	7019	490	40,800	178,704	0.020	0.796	3.48	0.020	0.796	3.48	0.005	0.204	0.89	6.6	6.60	57,816	0.007	0.049	0.22	0.007	0.049	0.22	0.002	0.016	0.07	0.051	0.337	1.47	0.260	1.716	7.52	0.005	0.033	0.14			
	7001	61	5,100	22,338	0.046	0.235	1.03	0.046	0.235	1.03	0.005	0.026	0.11		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	7027	61	5,100	22,338	0.008	0.041	0.18	0.008	0.041	0.18	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	7006	490	40,800	178,704	0.003	0.122	0.54	0.003	0.122	0.54	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
Process B	8	61	5,100	22,338	0.002	0.008	0.04	0.002	0.008	0.04	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	5001	61	5,100	22,338	0.008	0.041	0.18	0.008	0.041	0.18	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	5000	61	5,100	22,338	0.002	0.008	0.04	0.002	0.008	0.04	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	432	61	5,100	22,338	0.002	0.008	0.04	0.002	0.008	0.04	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	322	0.61	51	223	0.008	0.000	0.00	0.008	0.000	0.00	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
	572	3.06	255	1,117	0.038	0.010	0.04	0.038	0.010	0.04	-	-	-		0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			

	A	B	C	D
1				
2		Changes in Steam Supply and Capacity		
3			Steam Supply, lb/hr	
4		Parameter	max day	annual
5		Projected Future Steam Demand		
6		Baseline steam usage*	91,505	55,542
7		Added steam demand		
8		New Flake Production	72,000	72,000
9		Increased Process A Productio	621	621
10		Retired steam usage*	-21,075	-7,859
11		Projected future steam	143,051	120,304
12		Added steam capacity		
13		Boiler 1A	80,600	80,600
14		Boiler 2A	80,600	80,600
15		Total new steam capacity	161,200	161,200

	A	B	C	D	E	F	G	H	I	J	K
1	1	2	3	5			28		44	45	46
2											
3		Steam Production									
4	date	KIPPER, lbs steam	#1 BOILER, lbs steam	#2 BOILER, lbs steam	total steam, lbs	total steam, lb/hr	P4, lbs/day	P4, lbs/hr			
5	1/1/2016	0	384,849	1,371,872	1,756,721	73,197	14,800	617			
6	1/2/2016	0	465,368	1,243,847	1,709,215	71,217	20,800	867			
7	1/3/2016	0	469,402	1,290,028	1,759,430	73,310	23,600	983			
8	1/4/2016	0	467,633	1,272,004	1,739,637	72,485	23,200	967			
9	1/5/2016	0	463,220	1,103,149	1,566,369	65,265	20,400	850			
10	1/6/2016	0	459,661	1,221,012	1,680,673	70,028	17,850	744			
11	1/7/2016	0	455,492	1,210,141	1,665,633	69,401	47,518	1,980			
12	1/8/2016	0	450,947	1,182,936	1,633,883	68,078	22,950	956			
13	1/9/2016	0	456,584	1,217,428	1,674,012	69,751	48,450	2,019			
14	1/10/2016	0	466,065	1,267,144	1,733,209	72,217	18,700	779			
15	1/11/2016	0	542,857	1,042,120	1,584,977	66,041	47,600	1,983			
16	1/12/2016	0	526,639	1,153,853	1,680,492	70,021	0	0			
17	1/13/2016	0	493,090	1,047,094	1,540,184	64,174	22,500	938			
18	1/14/2016	0	426,241	1,230,116	1,656,357	69,015	18,000	750			
19	1/15/2016	0	230,795	307,675	538,470	22,436	10,400	433			
20	1/16/2016	439,109	335,028	417,143	1,191,280	49,637	5,200	217			
21	1/17/2016	697,499	389,267	2,653	1,089,419	45,392	30,800	1,283			
22	1/18/2016	742,075	395,431	16	1,137,522	47,397	17,200	717			
23	1/19/2016	816,791	357,470	142	1,174,403	48,933	27,600	1,150			
24	1/20/2016	876,318	339,923	2,841	1,219,082	50,795	16,800	700			
25	1/21/2016	739,589	405,321	29,090	1,174,000	48,917	21,600	900			
26	1/22/2016	791,546	463,522	6,288	1,261,356	52,557	19,200	800			
27	1/23/2016	861,879	416,200	0	1,278,079	53,253	23,600	983			
28	1/24/2016	820,032	461,114	4	1,281,150	53,381	26,000	1,083			
29	1/25/2016	874,433	435,176	0	1,309,609	54,567	22,400	933			
30	1/26/2016	807,132	423,172	0	1,230,304	51,263	12,400	517			
31	1/27/2016	807,950	446,223	0	1,254,173	52,257	12,750	531			
32	1/28/2016	793,383	430,808	0	1,224,191	51,008	28,500	1,188			
33	1/29/2016	718,899	364,430	0	1,083,329	45,139	19,550	815			
34	1/30/2016	650,147	275,931	39	926,117	38,588	26,350	1,098			
35	1/31/2016	712,334	382,107	3	1,094,444	45,602	15,300	638			
36	2/1/2016	605,809	413,974	88	1,019,871	42,495	42,500	1,771			
37	2/2/2016	543,277	385,141	23,518	951,936	39,664	9,350	390			
38	2/3/2016	711,279	433,844	1,703	1,146,826	47,784	33,150	1,381			
39	2/4/2016	773,543	382,137	12,432	1,168,112	48,671	35,700	1,488			
40	2/5/2016	732,838	319,249	119	1,052,206	43,842	15,300	638			
41	2/6/2016	798,389	411,470	5,055	1,214,914	50,621	21,600	900			
42	2/7/2016	565,081	0	1,073,994	1,639,075	68,295	20,800	867			
43	2/8/2016	666,759	0	1,097,712	1,764,471	73,520	29,600	1,233			
44	2/9/2016	787,983	0	809,031	1,597,014	66,542	12,400	517			
45	2/10/2016	677,869	0	1,067,033	1,744,902	72,704	22,800	950			
46	2/11/2016	659,952	0	1,108,521	1,768,473	73,686	34,000	1,417			

	A	B	C	D	E	F	G	H	I	J	K
47	2/12/2016	578,193	3	1,084,946	1,663,142	69,298	6,000	250			
48	2/13/2016	687,587	0	935,141	1,622,728	67,614	20,800	867			
49	2/14/2016	478,734	0	754,812	1,233,546	51,398	38,400	1,600			
50	2/15/2016	0	0	111,621	111,621	4,651	0	0			
51	2/16/2016	0	0	23	23	1	3,000	125			
52	2/17/2016	0	0	0	0	0	0	0			
53	2/18/2016	0	21,581	95,941	117,522	4,897	0	0			
54	2/19/2016	0	357,319	528,798	886,117	36,922	0	0			
55	2/20/2016	0	547,197	956,084	1,503,281	62,637	31,500	1,313			
56	2/21/2016	0	571,294	890,461	1,461,755	60,906	34,650	1,444			
57	2/22/2016	0	577,505	921,218	1,498,723	62,447	29,700	1,238			
58	2/23/2016	91,461	549,763	770,108	1,411,332	58,806	30,600	1,275			
59	2/24/2016	577,849	390,190	261	968,300	40,346	32,400	1,350			
60	2/25/2016	617,672	350,295	5	967,972	40,332	0	0			
61	2/26/2016	753,381	403,745	128	1,157,254	48,219	45,900	1,913			
62	2/27/2016	573,531	518,898	167	1,092,596	45,525	28,900	1,204			
63	2/28/2016	598,681	494,061	0	1,092,742	45,531	28,900	1,204			
64	2/29/2016	649,696	451,232	129,166	1,230,094	51,254	33,150	1,381			
65	3/1/2016	715,495	410,661	0	1,126,156	46,923	17,600	733			
66	3/2/2016	746,499	408,278	15	1,154,792	48,116	10,400	433			
67	3/3/2016	771,518	417,981	12	1,189,511	49,563	26,000	1,083			
68	3/4/2016	824,345	418,817	2,826	1,245,988	51,916	18,000	750			
69	3/5/2016	773,003	392,945	96,671	1,262,619	52,609	27,600	1,150			
70	3/6/2016	793,361	389,905	568	1,183,834	49,326	20,800	867			
71	3/7/2016	579,060	192,623	226,792	998,475	41,603	18,800	783			
72	3/8/2016	923,193	200,462	85,243	1,208,898	50,371	25,600	1,067			
73	3/9/2016	639,055	227,162	519,492	1,385,709	57,738	24,800	1,033			
74	3/10/2016	0	388,952	1,208,108	1,597,060	66,544	29,200	1,217			
75	3/11/2016	0	355,410	1,269,497	1,624,907	67,704	22,400	933			
76	3/12/2016	0	390,757	1,237,128	1,627,885	67,829	17,200	717			
77	3/13/2016	0	387,065	1,244,997	1,632,062	68,003	26,400	1,100			
78	3/14/2016	0	397,472	1,230,798	1,628,270	67,845	25,200	1,050			
79	3/15/2016	0	437,197	1,131,174	1,568,371	65,349	15,600	650			
80	3/16/2016	0	441,093	1,103,678	1,544,771	64,365	0	0			
81	3/17/2016	0	442,094	1,117,896	1,559,990	65,000	38,900	1,621			
82	3/18/2016	0	435,552	1,218,492	1,654,044	68,919	33,150	1,381			
83	3/19/2016	0	461,139	1,238,177	1,699,316	70,805	20,400	850			
84	3/20/2016	0	463,284	1,141,207	1,604,491	66,854	42,500	1,771			
85	3/21/2016	0	417,969	1,014,232	1,432,201	59,675	34,000	1,417			
86	3/22/2016	216,587	3,510	661,224	881,321	36,722	11,900	496			
87	3/23/2016	703,830	35,081	708,514	1,447,425	60,309	17,182	716			
88	3/24/2016	573,217	262,485	196,129	1,031,831	42,993	29,658	1,236			
89	3/25/2016	739,813	217,285	207,327	1,164,425	48,518	29,983	1,249			
90	3/26/2016	640,072	396,219	213,336	1,249,627	52,068	29,600	1,233			
91	3/27/2016	97,362	473,172	890,387	1,460,921	60,872	32,800	1,367			
92	3/28/2016	0	497,790	1,047,283	1,545,073	64,378	42,715	1,780			
93	3/29/2016	0	479,549	1,181,516	1,661,065	69,211	0	0			

	A	B	C	D	E	F	G	H	I	J	K
94	3/30/2016	0	494,296	1,014,027	1,508,323	62,847	7,600	317			
95	3/31/2016	0	496,683	842,133	1,338,816	55,784	0	0			
96	4/1/2016	0	493,056	1,003,634	1,496,690	62,362	7,600	317			
97	4/2/2016	0	487,313	981,712	1,469,025	61,209	16,800	700			
98	4/3/2016	0	489,897	1,017,188	1,507,085	62,795	26,400	1,100			
99	4/4/2016	0	510,362	977,161	1,487,523	61,980	20,400	850			
100	4/5/2016	0	551,311	981,649	1,532,960	63,873	19,600	817			
101	4/6/2016	0	555,912	1,002,746	1,558,658	64,944	10,000	417			
102	4/7/2016	0	471,319	794,405	1,265,724	52,739	29,200	1,217			
103	4/8/2016	0	437,878	763,374	1,201,252	50,052	16,000	667			
104	4/9/2016	0	440,259	858,383	1,298,642	54,110	21,200	883			
105	4/10/2016	0	497,331	1,089,982	1,587,313	66,138	20,800	867			
106	4/11/2016	0	514,233	1,025,813	1,540,046	64,169	11,600	483			
107	4/12/2016	0	539,765	983,512	1,523,277	63,470	20,800	867			
108	4/13/2016	0	469,003	757,949	1,226,952	51,123	18,266	761			
109	4/14/2016	0	441,131	756,034	1,197,165	49,882	18,450	769			
110	4/15/2016	0	431,442	671,495	1,102,937	45,956	29,250	1,219			
111	4/16/2016	0	441,439	705,299	1,146,738	47,781	31,500	1,313			
112	4/17/2016	0	478,729	775,740	1,254,469	52,270	36,000	1,500			
113	4/18/2016	0	490,915	1,010,561	1,501,476	62,562	23,850	994			
114	4/19/2016	0	518,912	939,058	1,457,970	60,749	40,500	1,688			
115	4/20/2016	0	538,497	856,411	1,394,908	58,121	18,900	788			
116	4/21/2016	0	533,507	837,291	1,370,798	57,117	12,800	533			
117	4/22/2016	0	540,576	872,975	1,413,551	58,898	22,800	950			
118	4/23/2016	0	510,001	727,287	1,237,288	51,554	23,600	983			
119	4/24/2016	0	493,524	728,657	1,222,181	50,924	24,000	1,000			
120	4/25/2016	0	550,006	894,317	1,444,323	60,180	17,200	717			
121	4/26/2016	0	555,464	901,616	1,457,080	60,712	22,000	917			
122	4/27/2016	0	559,342	911,701	1,471,043	61,293	17,086	712			
123	4/28/2016	0	554,708	969,469	1,524,177	63,507	33,668	1,403			
124	4/29/2016	0	484,945	828,828	1,313,773	54,741	34,936	1,456			
125	4/30/2016	0	529,042	984,561	1,513,603	63,067	30,949	1,290			
126	5/1/2016	0	533,747	996,281	1,530,028	63,751	40,462	1,686			
127	5/2/2016	0	475,256	960,685	1,435,941	59,831	41,199	1,717			
128	5/3/2016	0	235,843	963,812	1,199,655	49,986	0	0			
129	5/4/2016	0	526,008	927,154	1,453,162	60,548	48,660	2,028			
130	5/5/2016	0	566,352	965,311	1,531,663	63,819	50,380	2,099			
131	5/6/2016	0	543,968	1,021,305	1,565,273	65,220	23,036	960			
132	5/7/2016	0	521,859	1,114,879	1,636,738	68,197	26,848	1,119			
133	5/8/2016	0	516,665	1,140,149	1,656,814	69,034	32,012	1,334			
134	5/9/2016	0	508,106	967,899	1,476,005	61,500	52,164	2,174			
135	5/10/2016	0	524,242	648,075	1,172,317	48,847	3,200	133			
136	5/11/2016	0	526,712	647,286	1,173,998	48,917	0	0			
137	5/12/2016	0	516,714	652,063	1,168,777	48,699	0	0			
138	5/13/2016	0	174,937	121,236	296,173	12,341	0	0			
139	5/14/2016	0	0	0	0	0	0	0			
140	5/15/2016	0	257	0	257	11	0	0			

	A	B	C	D	E	F	G	H	I	J	K
141	5/16/2016	0	205,758	67,335	273,093	11,379	0	0			
142	5/17/2016	0	557,518	860,463	1,417,981	59,083	10,800	450			
143	5/18/2016	0	518,274	953,171	1,471,445	61,310	35,550	1,481			
144	5/19/2016	0	517,640	1,027,364	1,545,004	64,375	27,450	1,144			
145	5/20/2016	0	540,857	915,909	1,456,766	60,699	37,350	1,556			
146	5/21/2016	0	465,189	794,346	1,259,535	52,481	25,200	1,050			
147	5/22/2016	0	463,514	757,873	1,221,387	50,891	34,200	1,425			
148	5/23/2016	0	456,611	834,677	1,291,288	53,804	27,900	1,163			
149	5/24/2016	0	434,282	726,883	1,161,165	48,382	25,650	1,069			
150	5/25/2016	0	438,126	759,029	1,197,155	49,881	24,750	1,031			
151	5/26/2016	0	439,940	810,378	1,250,318	52,097	25,200	1,050			
152	5/27/2016	0	444,617	797,014	1,241,631	51,735	26,550	1,106			
153	5/28/2016	0	481,872	889,717	1,371,589	57,150	37,350	1,556			
154	5/29/2016	0	469,562	833,565	1,303,127	54,297	30,600	1,275			
155	5/30/2016	0	487,507	880,870	1,368,377	57,016	33,750	1,406			
156	5/31/2016	0	499,805	939,986	1,439,791	59,991	32,400	1,350			
157	6/1/2016	0	500,039	929,679	1,429,718	59,572	21,600	900			
158	6/2/2016	0	488,307	889,551	1,377,858	57,411	40,950	1,706			
159	6/3/2016	0	494,250	861,581	1,355,831	56,493	27,450	1,144			
160	6/4/2016	0	455,484	980,982	1,436,466	59,853	34,650	1,444			
161	6/5/2016	0	460,089	980,568	1,440,657	60,027	27,000	1,125			
162	6/6/2016	0	481,117	886,875	1,367,992	57,000	24,300	1,013			
163	6/7/2016	0	544,952	685,318	1,230,270	51,261	30,150	1,256			
164	6/8/2016	0	564,207	767,156	1,331,363	55,473	41,850	1,744			
165	6/9/2016	0	558,576	863,109	1,421,685	59,237	26,550	1,106			
166	6/10/2016	0	561,558	875,358	1,436,916	59,872	23,850	994			
167	6/11/2016	0	591,004	947,900	1,538,904	64,121	35,100	1,463			
168	6/12/2016	0	572,085	834,099	1,406,184	58,591	26,267	1,094			
169	6/13/2016	0	542,358	879,623	1,421,981	59,249	18,000	750			
170	6/14/2016	0	541,891	1,052,285	1,594,176	66,424	31,050	1,294			
171	6/15/2016	0	516,413	904,089	1,420,502	59,188	13,050	544			
172	6/16/2016	0	521,236	1,001,745	1,522,981	63,458	9,520	397			
173	6/17/2016	0	545,580	853,634	1,399,214	58,301	45,414	1,892			
174	6/18/2016	0	531,681	983,623	1,515,304	63,138	34,422	1,434			
175	6/19/2016	0	533,526	986,857	1,520,383	63,349	28,514	1,188			
176	6/20/2016	0	519,447	1,024,363	1,543,810	64,325	51,956	2,165			
177	6/21/2016	0	465,360	847,831	1,313,191	54,716	27,062	1,128			
178	6/22/2016	0	486,582	931,832	1,418,414	59,101	14,650	610			
179	6/23/2016	0	505,149	1,021,829	1,526,978	63,624	21,576	899			
180	6/24/2016	0	537,517	1,042,843	1,580,360	65,848	45,352	1,890			
181	6/25/2016	0	562,084	995,580	1,557,664	64,903	36,080	1,503			
182	6/26/2016	0	567,173	950,902	1,518,075	63,253	40,254	1,677			
183	6/27/2016	0	565,650	930,737	1,496,387	62,349	38,794	1,616			
184	6/28/2016	0	555,182	1,011,384	1,566,566	65,274	40,488	1,687			
185	6/29/2016	0	546,609	783,849	1,330,458	55,436	36,799	1,533			
186	6/30/2016	0	482,081	372,697	854,778	35,616	15,090	629			
187	7/1/2016	0	433,833	669,184	1,103,017	45,959	0	0			

	A	B	C	D	E	F	G	H	I	J	K
188	7/2/2016	0	448,796	754,756	1,203,552	50,148	0	0			
189	7/3/2016	0	444,511	725,264	1,169,775	48,741	0	0			
190	7/4/2016	0	434,671	659,266	1,093,937	45,581	0	0			
191	7/5/2016	0	450,264	767,583	1,217,847	50,744	0	0			
192	7/6/2016	0	465,301	827,616	1,292,917	53,872	0	0			
193	7/7/2016	0	426,035	675,877	1,101,912	45,913	850	35			
194	7/8/2016	0	415,443	470,398	885,841	36,910	0	0			
195	7/9/2016	0	456,972	767,297	1,224,269	51,011	0	0			
196	7/10/2016	0	465,171	808,206	1,273,377	53,057	0	0			
197	7/11/2016	0	480,358	636,028	1,116,386	46,516	0	0			
198	7/12/2016	0	495,029	685,783	1,180,812	49,201	0	0			
199	7/13/2016	0	472,342	550,255	1,022,597	42,608	0	0			
200	7/14/2016	0	64,512	101,684	166,196	6,925	0	0			
201	7/15/2016	0	189,960	256,638	446,598	18,608	800	33			
202	7/16/2016	0	441,143	334,089	775,232	32,301	0	0			
203	7/17/2016	0	496,107	595,290	1,091,397	45,475	0	0			
204	7/18/2016	0	487,626	636,761	1,124,387	46,849	0	0			
205	7/19/2016	0	404,282	543,091	947,373	39,474	0	0			
206	7/20/2016	0	491,303	600,521	1,091,824	45,493	0	0			
207	7/21/2016	0	495,006	637,296	1,132,302	47,179	0	0			
208	7/22/2016	0	501,677	423,465	925,142	38,548	0	0			
209	7/23/2016	0	242,863	0	242,863	10,119	0	0			
210	7/24/2016	0	262,215	0	262,215	10,926	0	0			
211	7/25/2016	0	306,659	0	306,659	12,777	0	0			
212	7/26/2016	567,846	174,808	0	742,654	30,944	1,800	75			
213	7/27/2016	1,004,637	36,924	0	1,041,561	43,398	13,500	563			
214	7/28/2016	990,047	23,573	0	1,013,620	42,234	36,000	1,500			
215	7/29/2016	937,842	73,596	0	1,011,438	42,143	5,500	229			
216	7/30/2016	963,362	82,118	0	1,045,480	43,562	28,600	1,192			
217	7/31/2016	999,893	78,700	0	1,078,593	44,941	27,500	1,146			
218	8/1/2016	835,617	115,690	0	951,307	39,638	0	0			
219	8/2/2016	872,034	166,619	0	1,038,653	43,277	22,406	934			
220	8/3/2016	850,550	199,792	0	1,050,342	43,764	23,850	994			
221	8/4/2016	860,110	183,546	0	1,043,656	43,486	36,000	1,500			
222	8/5/2016	886,852	187,205	0	1,074,057	44,752	21,150	881			
223	8/6/2016	916,972	164,766	0	1,081,738	45,072	12,150	506			
224	8/7/2016	516,589	182,734	6,887	706,210	29,425	41,850	1,744			
225	8/8/2016	0	356,335	0	356,335	14,847	3,150	131			
226	8/9/2016	0	336,079	0	336,079	14,003	0	0			
227	8/10/2016	276,353	283,079	0	559,432	23,310	0	0			
228	8/11/2016	794,039	181,338	0	975,377	40,641	0	0			
229	8/12/2016	1,032,444	185,209	0	1,217,653	50,736	0	0			
230	8/13/2016	1,043,746	181,992	0	1,225,738	51,072	750	31			
231	8/14/2016	1,026,852	182,663	0	1,209,515	50,396	23,650	985			
232	8/15/2016	1,005,557	184,427	0	1,189,984	49,583	27,050	1,127			
233	8/16/2016	965,358	200,284	17,768	1,183,410	49,309	27,170	1,132			
234	8/17/2016	1,001,651	246,136	10,404	1,258,191	52,425	30,256	1,261			

	A	B	C	D	E	F	G	H	I	J	K
235	8/18/2016	804,214	183,102	16,272	1,003,588	41,816	31,410	1,309			
236	8/19/2016	927,379	206,952	0	1,134,331	47,264	10,234	426			
237	8/20/2016	970,492	216,645	0	1,187,137	49,464	27,074	1,128			
238	8/21/2016	892,462	220,858	0	1,113,320	46,388	20,600	858			
239	8/22/2016	806,472	177,889	0	984,361	41,015	43,553	1,815			
240	8/23/2016	734,055	205,383	0	939,438	39,143	33,075	1,378			
241	8/24/2016	895,154	326,523	0	1,221,677	50,903	18,082	753			
242	8/25/2016	420,952	394,037	0	814,989	33,958	32,988	1,375			
243	8/26/2016	703,967	414,419	0	1,118,386	46,599	30,869	1,286			
244	8/27/2016	774,100	414,991	0	1,189,091	49,545	20,351	848			
245	8/28/2016	705,114	467,660	0	1,172,774	48,866	27,212	1,134			
246	8/29/2016	708,529	444,346	0	1,152,875	48,036	19,004	792			
247	8/30/2016	776,526	456,403	0	1,232,929	51,372	23,794	991			
248	8/31/2016	766,607	409,891	0	1,176,498	49,021	35,002	1,458			
249	9/1/2016	798,969	430,189	0	1,229,158	51,215	14,850	619			
250	9/2/2016	767,795	359,670	0	1,127,465	46,978	24,750	1,031			
251	9/3/2016	957,699	256,207	0	1,213,906	50,579	34,650	1,444			
252	9/4/2016	840,198	382,038	0	1,222,236	50,927	21,150	881			
253	9/5/2016	901,235	324,305	0	1,225,540	51,064	36,000	1,500			
254	9/6/2016	653,704	401,970	0	1,055,674	43,986	26,550	1,106			
255	9/7/2016	776,130	431,631	0	1,207,761	50,323	18,900	788			
256	9/8/2016	742,679	417,929	0	1,160,608	48,359	30,600	1,275			
257	9/9/2016	787,902	387,392	0	1,175,294	48,971	23,400	975			
258	9/10/2016	796,837	343,202	0	1,140,039	47,502	46,526	1,939			
259	9/11/2016	666,835	423,290	0	1,090,125	45,422	0	0			
260	9/12/2016	847,003	343,154	0	1,190,157	49,590	770	32			
261	9/13/2016	772,418	427,098	0	1,199,516	49,980	20,629	860			
262	9/14/2016	800,056	458,277	0	1,258,333	52,431	15,942	664			
263	9/15/2016	879,677	441,901	0	1,321,578	55,066	20,516	855			
264	9/16/2016	838,336	408,088	18,238	1,264,662	52,694	18,846	785			
265	9/17/2016	887,064	333,100	41,819	1,261,983	52,583	23,258	969			
266	9/18/2016	856,032	306,874	14,924	1,177,830	49,076	29,144	1,214			
267	9/19/2016	827,506	304,780	0	1,132,286	47,179	28,092	1,171			
268	9/20/2016	806,334	67,956	5,920	880,210	36,675	32,472	1,353			
269	9/21/2016	1,225,514	0	20,170	1,245,684	51,904	4,460	186			
270	9/22/2016	437,199	0	284,956	722,155	30,090	11,334	472			
271	9/23/2016	1,127,578	0	131,700	1,259,278	52,470	19,502	813			
272	9/24/2016	796,291	0	0	796,291	33,179	8,180	341			
273	9/25/2016	1,322,222	0	0	1,322,222	55,093	23,654	986			
274	9/26/2016	1,333,152	0	0	1,333,152	55,548	22,760	948			
275	9/27/2016	1,281,494	0	11,131	1,292,625	53,859	29,946	1,248			
276	9/28/2016	1,304,727	0	0	1,304,727	54,364	31,448	1,310			
277	9/29/2016	947,102	0	0	947,102	39,463	26,984	1,124			
278	9/30/2016	1,299,924	0	73,059	1,372,983	57,208	21,016	876			
279	10/1/2016	1,152,840	0	216,505	1,369,345	57,056	22,088	920			
280	10/2/2016	966,243	0	279,523	1,245,766	51,907	7,200	300			
281	10/3/2016	1,004,469	0	366,933	1,371,402	57,142	27,200	1,133			

	A	B	C	D	E	F	G	H	I	J	K
282	10/4/2016	1,005,983	0	544,014	1,549,997	64,583	25,132	1,047			
283	10/5/2016	907,467	0	716,551	1,624,018	67,667	33,365	1,390			
284	10/6/2016	758,936	1	444,598	1,203,535	50,147	33,248	1,385			
285	10/7/2016	687,644	0	124,670	812,314	33,846	0	0			
286	10/8/2016	597,114	0	146,768	743,882	30,995	0	0			
287	10/9/2016	140,520	75	7,752	148,347	6,181	0	0			
288	10/10/2016	0	0	0	0	0	0	0			
289	10/11/2016	0	0	51	51	2	0	0			
290	10/12/2016	0	0	18	18	1	0	0			
291	10/13/2016	0	0	2	2	0	0	0			
292	10/14/2016	0	5,416	65	5,481	228	0	0			
293	10/15/2016	0	0	363,957	363,957	15,165	0	0			
294	10/16/2016	0	0	449,091	449,091	18,712	0	0			
295	10/17/2016	0	0	142,990	142,990	5,958	0	0			
296	10/18/2016	17,747	107,355	159,992	285,094	11,879	0	0			
297	10/19/2016	0	98,767	14,688	113,455	4,727	0	0			
298	10/20/2016	0	25,246	901	26,147	1,089	0	0			
299	10/21/2016	0	30,852	1,403	32,255	1,344	0	0			
300	10/22/2016	0	12,139	119	12,258	511	0	0			
301	10/23/2016	0	293,907	126,181	420,088	17,504	0	0			
302	10/24/2016	0	534,731	756,456	1,291,187	53,799	2,250	94			
303	10/25/2016	0	549,727	1,211,814	1,761,541	73,398	33,750	1,406			
304	10/26/2016	0	565,945	1,097,247	1,663,192	69,300	29,700	1,238			
305	10/27/2016	0	566,499	1,043,415	1,609,914	67,080	30,150	1,256			
306	10/28/2016	0	561,020	1,118,970	1,679,990	70,000	19,800	825			
307	10/29/2016	0	565,348	1,083,176	1,648,524	68,689	35,550	1,481			
308	10/30/2016	0	565,859	1,132,537	1,698,396	70,767	17,550	731			
309	10/31/2016	0	536,197	988,360	1,524,557	63,523	38,700	1,613			
310	11/1/2016	0	558,946	1,222,184	1,781,130	74,214	26,550	1,106			
311	11/2/2016	0	561,852	1,228,370	1,790,222	74,593	31,500	1,313			
312	11/3/2016	0	565,763	1,119,188	1,684,951	70,206	23,850	994			
313	11/4/2016	0	575,907	1,139,871	1,715,778	71,491	37,800	1,575			
314	11/5/2016	0	579,086	1,087,226	1,666,312	69,430	39,600	1,650			
315	11/6/2016	0	563,250	1,042,701	1,605,951	66,915	40,950	1,706			
316	11/7/2016	0	561,976	1,114,136	1,676,112	69,838	31,500	1,313			
317	11/8/2016	0	567,664	1,107,052	1,674,716	69,780	40,050	1,669			
318	11/9/2016	0	563,842	1,178,886	1,742,728	72,614	33,300	1,388			
319	11/10/2016	0	499,593	950,943	1,450,536	60,439	26,550	1,106			
320	11/11/2016	0	596,459	1,239,948	1,836,407	76,517	31,950	1,331			
321	11/12/2016	0	605,999	1,238,160	1,844,159	76,840	31,950	1,331			
322	11/13/2016	0	607,968	1,144,735	1,752,703	73,029	28,800	1,200			
323	11/14/2016	0	587,634	752,063	1,339,697	55,821	21,289	887			
324	11/15/2016	0	562,310	1,035,251	1,597,561	66,565	0	0			
325	11/16/2016	0	555,569	1,214,407	1,769,976	73,749	25,584	1,066			
326	11/17/2016	0	562,397	1,220,736	1,783,133	74,297	29,579	1,232			
327	11/18/2016	0	555,126	1,002,386	1,557,512	64,896	27,778	1,157			
328	11/19/2016	0	563,125	1,188,195	1,751,320	72,972	41,752	1,740			

	A	B	C	D	E	F	G	H	I	J	K
329	11/20/2016	0	569,815	1,238,416	1,808,231	75,343	39,149	1,631			
330	11/21/2016	0	567,906	1,225,312	1,793,218	74,717	19,550	815			
331	11/22/2016	0	567,578	1,225,945	1,793,523	74,730	44,576	1,857			
332	11/23/2016	0	566,006	1,157,202	1,723,208	71,800	40,078	1,670			
333	11/24/2016	0	580,389	1,220,341	1,800,730	75,030	40,874	1,703			
334	11/25/2016	0	573,930	1,213,681	1,787,611	74,484	21,000	875			
335	11/26/2016	0	570,705	1,251,202	1,821,907	75,913	30,420	1,268			
336	11/27/2016	0	565,289	1,181,714	1,747,003	72,792	28,932	1,206			
337	11/28/2016	0	509,439	962,516	1,471,955	61,331	37,425	1,559			
338	11/29/2016	0	566,801	967,182	1,533,983	63,916	29,010	1,209			
339	11/30/2016	0	551,341	990,632	1,541,973	64,249	20,830	868			
340	12/1/2016	0	609,901	1,156,261	1,766,162	73,590	28,194	1,175			
341	12/2/2016	0	605,921	1,032,635	1,638,556	68,273	40,632	1,693			
342	12/3/2016	0	615,239	1,101,621	1,716,860	71,536	33,674	1,403			
343	12/4/2016	0	603,553	1,021,792	1,625,345	67,723	10,364	432			
344	12/5/2016	0	588,246	1,179,237	1,767,483	73,645	40,950	1,706			
345	12/6/2016	0	435,761	1,000,596	1,436,357	59,848	20,700	863			
346	12/7/2016	0	447,099	1,250,266	1,697,365	70,724	15,570	649			
347	12/8/2016	0	429,614	938,012	1,367,626	56,984	20,554	856			
348	12/9/2016	0	526,934	1,235,252	1,762,186	73,424	29,041	1,210			
349	12/10/2016	0	475,354	1,189,231	1,664,585	69,358	49,478	2,062			
350	12/11/2016	0	498,048	1,191,909	1,689,957	70,415	21,250	885			
351	12/12/2016	0	520,282	1,206,138	1,726,420	71,934	53,337	2,222			
352	12/13/2016	0	523,393	1,264,468	1,787,861	74,494	34,750	1,448			
353	12/14/2016	0	522,053	1,268,079	1,790,132	74,589	42,788	1,783			
354	12/15/2016	0	522,758	1,244,394	1,767,152	73,631	38,502	1,604			
355	12/16/2016	0	528,046	1,282,278	1,810,324	75,430	35,876	1,495			
356	12/17/2016	0	549,580	1,292,412	1,841,992	76,750	32,300	1,346			
357	12/18/2016	0	585,893	1,199,901	1,785,794	74,408	39,340	1,639			
358	12/19/2016	0	606,150	1,154,974	1,761,124	73,380	56,820	2,368			
359	12/20/2016	0	572,873	1,106,424	1,679,297	69,971	14,400	600			
360	12/21/2016	0	543,174	1,198,252	1,741,426	72,559	38,700	1,613			
361	12/22/2016	0	539,260	1,172,532	1,711,792	71,325	46,800	1,950			
362	12/23/2016	0	529,073	1,079,381	1,608,454	67,019	38,250	1,594			
363	12/24/2016	0	543,036	1,144,006	1,687,042	70,293	30,150	1,256			
364	12/25/2016	0	499,849	947,761	1,447,610	60,317	36,900	1,538			
365	12/26/2016	0	530,740	1,002,758	1,533,498	63,896	32,850	1,369			
366	12/27/2016	0	550,888	1,127,484	1,678,372	69,932	42,300	1,763			
367	12/28/2016	0	545,431	1,178,199	1,723,630	71,818	18,900	788			
368	12/29/2016	0	508,268	1,069,894	1,578,162	65,757	37,800	1,575			
369	12/30/2016	0	507,486	1,173,548	1,681,034	70,043	30,600	1,275			
370	12/31/2016	0	617,161	1,087,043	1,704,204	71,009	36,900	1,538			
371	1/1/2017	0	572,849	1,065,992	1,638,841	68,285	21,150	881			
372	1/2/2017	0	557,786	1,140,825	1,698,611	70,775	37,800	1,575			
373	1/3/2017	0	527,125	864,737	1,391,862	57,994	13,950	581			
374	1/4/2017	0	536,313	860,564	1,396,877	58,203	17,030	710			
375	1/5/2017	0	529,586	834,461	1,364,047	56,835	850	35			

	A	B	C	D	E	F	G	H	I	J	K
376	1/6/2017	0	532,785	755,050	1,287,835	53,660	0	0			
377	1/7/2017	0	542,850	811,677	1,354,527	56,439	0	0			
378	1/8/2017	0	542,108	802,990	1,345,098	56,046	0	0			
379	1/9/2017	0	537,950	983,762	1,521,712	63,405	0	0			
380	1/10/2017	0	592,902	1,272,308	1,865,210	77,717	8,906	371			
381	1/11/2017	0	274,893	1,261,069	1,535,962	63,998	38,422	1,601			
382	1/12/2017	0	198,429	1,305,390	1,503,819	62,659	36,896	1,537			
383	1/13/2017	0	0	1,116,619	1,116,619	46,526	37,387	1,558			
384	1/14/2017	0	0	1,072,715	1,072,715	44,696	9,000	375			
385	1/15/2017	0	0	1,053,943	1,053,943	43,914	55,974	2,332			
386	1/16/2017	0	0	1,070,057	1,070,057	44,586	11,462	478			
387	1/17/2017	0	0	1,079,864	1,079,864	44,994	48,341	2,014			
388	1/18/2017	0	0	1,090,536	1,090,536	45,439	26,056	1,086			
389	1/19/2017	0	471,841	1,050,572	1,522,413	63,434	43,892	1,829			
390	1/20/2017	0	668,699	1,026,443	1,695,142	70,631	37,432	1,560			
391	1/21/2017	0	389,186	1,058,794	1,447,980	60,333	17,348	723			
392	1/22/2017	0	371,900	1,109,768	1,481,668	61,736	20,896	871			
393	1/23/2017	0	759,932	1,071,556	1,831,488	76,312	43,166	1,799			
394	1/24/2017	0	251,379	1,239,371	1,490,750	62,115	27,892	1,162			
395	1/25/2017	0	0	1,231,743	1,231,743	51,323	53,077	2,212			
396	1/26/2017	0	0	1,206,102	1,206,102	50,254	34,376	1,432			
397	1/27/2017	0	0	1,253,013	1,253,013	52,209	57,736	2,406			
398	1/28/2017	0	0	1,375,798	1,375,798	57,325	9,150	381			
399	1/29/2017	0	0	960,338	960,338	40,014	38,827	1,618			
400	1/30/2017	0	0	0	0	0	21,334	889			
401	1/31/2017	0	0	0	0	0	20,773	866			
402	2/1/2017	359	48	387,977	388,384	16,183	49,463	2,061			
403	2/2/2017	0	0	677,984	677,984	28,249	6,662	278			
404	2/3/2017	0	282,883	1,015,510	1,298,393	54,100	45,286	1,887			
405	2/4/2017	0	676,864	1,297,515	1,974,379	82,266	38,570	1,607			
406	2/5/2017	0	917,761	1,278,352	2,196,113	91,505	40,952	1,706			
407	2/6/2017	0	917,740	1,133,334	2,051,074	85,461	34,486	1,437			
408	2/7/2017	0	917,750	1,185,662	2,103,412	87,642	71,149	2,965			
409	2/8/2017	102,805	702,602	1,183,244	1,988,651	82,860	59,929	2,497			
410	2/9/2017	0	116,733	151,580	268,313	11,180	14,620	609			
411	2/10/2017	0	223,088	808,031	1,031,119	42,963	0	0			
412	2/11/2017	0	366,824	1,087,391	1,454,215	60,592	41,254	1,719			
413	2/12/2017	0	0	1,088,774	1,088,774	45,366	11,900	496			
414	2/13/2017	0	223,625	1,112,895	1,336,520	55,688	49,210	2,050			
415	2/14/2017	0	328,286	1,110,745	1,439,031	59,960	26,656	1,111			
416	2/15/2017	0	299,164	1,124,529	1,423,693	59,321	56,355	2,348			
417	2/16/2017	0	275,520	1,182,472	1,457,992	60,750	33,374	1,391			
418	2/17/2017	0	224,400	1,227,110	1,451,510	60,480	11,200	467			
419	2/18/2017	0	0	1,165,141	1,165,141	48,548	57,742	2,406			
420	2/19/2017	0	0	1,165,864	1,165,864	48,578	21,916	913			
421	2/20/2017	0	0	955,882	955,882	39,828	54,786	2,283			
422	2/21/2017	0	0	3,925	3,925	164	0	0			

	A	B	C	D	E	F	G	H	I	J	K
423	2/22/2017	0	880,743	606,667	1,487,410	61,975	0	0			
424	2/23/2017	0	797,087	864,812	1,661,899	69,246	43,514	1,813			
425	2/24/2017	0	910,393	817,583	1,727,976	71,999	28,191	1,175			
426	2/25/2017	0	857,770	812,890	1,670,660	69,611	31,500	1,313			
427	2/26/2017	0	766,038	801,067	1,567,105	65,296	27,900	1,163			
428	2/27/2017	0	913,822	734,767	1,648,589	68,691	35,100	1,463			
429	2/28/2017	0	913,665	848,500	1,762,165	73,424	18,000	750			
430	3/1/2017	0	913,687	857,789	1,771,476	73,812	36,000	1,500			
431	3/2/2017	0	905,827	866,382	1,772,209	73,842	34,200	1,425			
432	3/3/2017	0	913,843	789,597	1,703,440	70,977	27,000	1,125			
433	3/4/2017	0	913,748	851,844	1,765,592	73,566	33,750	1,406			
434	3/5/2017	0	818,969	784,908	1,603,877	66,828	18,000	750			
435	3/6/2017	0	915,749	863,365	1,779,114	74,130	18,000	750			
436	3/7/2017	0	931,643	946,751	1,878,394	78,266	21,600	900			
437	3/8/2017	0	931,352	854,648	1,786,000	74,417	36,900	1,538			
438	3/9/2017	0	931,385	803,868	1,735,253	72,302	29,250	1,219			
439	3/10/2017	0	931,383	704,131	1,635,514	68,146	40,500	1,688			
440	3/11/2017	0	931,809	557,860	1,489,669	62,070	25,200	1,050			
441	3/12/2017	0	931,515	870,271	1,801,786	75,074	39,600	1,650			
442	3/13/2017	0	882,975	672,123	1,555,098	64,796	32,400	1,350			
443	3/14/2017	0	699,246	507,868	1,207,114	50,296	8,550	356			
444	3/15/2017	0	930,869	723,619	1,654,488	68,937	33,200	1,383			
445	3/16/2017	0	930,735	738,589	1,669,324	69,555	30,000	1,250			
446	3/17/2017	0	583,911	916,318	1,500,229	62,510	22,996	958			
447	3/18/2017	0	838,457	823,609	1,662,066	69,253	27,410	1,142			
448	3/19/2017	0	930,314	877,550	1,807,864	75,328	21,150	881			
449	3/20/2017	0	560,531	733,934	1,294,465	53,936	16,200	675			
450	3/21/2017	0	480,834	647,526	1,128,360	47,015	0	0			
451	3/22/2017	0	538,622	1,204,299	1,742,921	72,622	37,350	1,556			
452	3/23/2017	0	601,725	1,100,321	1,702,046	70,919	18,108	755			
453	3/24/2017	0	577,029	1,155,388	1,732,417	72,184	54,000	2,250			
454	3/25/2017	0	598,103	1,307,761	1,905,864	79,411	24,300	1,013			
455	3/26/2017	0	600,806	1,365,381	1,966,187	81,924	22,500	938			
456	3/27/2017	0	587,046	1,180,097	1,767,143	73,631	46,350	1,931			
457	3/28/2017	0	626,338	1,246,080	1,872,418	78,017	20,250	844			
458	3/29/2017	0	624,600	1,173,379	1,797,979	74,916	16,000	667			
459	3/30/2017	0	608,082	1,234,930	1,843,012	76,792	34,024	1,418			
460	3/31/2017	0	585,354	1,225,297	1,810,651	75,444	27,160	1,132			
461	4/1/2017	0	588,483	1,073,399	1,661,882	69,245	36,152	1,506			
462	4/2/2017	0	606,901	1,187,672	1,794,573	74,774	27,200	1,133			
463	4/3/2017	0	580,537	928,249	1,508,786	62,866	0	0			
464	4/4/2017	0	577,786	834,790	1,412,576	58,857	8,064	336			
465	4/5/2017	0	570,035	782,329	1,352,364	56,349	19,744	823			
466	4/6/2017	0	563,315	775,914	1,339,229	55,801	0	0			
467	4/7/2017	0	447,063	379,271	826,334	34,431	0	0			
468	4/8/2017	0	564,985	742,391	1,307,376	54,474	0	0			
469	4/9/2017	0	578,727	819,315	1,398,042	58,252	0	0			

	A	B	C	D	E	F	G	H	I	J	K
470	4/10/2017	0	561,669	351,848	913,517	38,063	0	0			
471	4/11/2017	0	280,901	117,655	398,556	16,607	0	0			
472	4/12/2017	0	519,643	202,293	721,936	30,081	0	0			
473	4/13/2017	0	513,827	817,784	1,331,611	55,484	0	0			
474	4/14/2017	0	518,334	863,696	1,382,030	57,585	0	0			
475	4/15/2017	0	521,871	866,134	1,388,005	57,834	0	0			
476	4/16/2017	0	529,147	893,412	1,422,559	59,273	0	0			
477	4/17/2017	0	568,794	1,197,308	1,766,102	73,588	0	0			
478	4/18/2017	0	566,625	1,132,468	1,699,093	70,796	31,910	1,330			
479	4/19/2017	0	604,998	1,257,141	1,862,139	77,589	31,568	1,315			
480	4/20/2017	0	611,820	1,246,788	1,858,608	77,442	18,938	789			
481	4/21/2017	0	591,165	1,195,756	1,786,921	74,455	24,061	1,003			
482	4/22/2017	0	601,910	1,174,215	1,776,125	74,005	32,400	1,350			
483	4/23/2017	0	595,775	1,290,015	1,885,790	78,575	14,850	619			
484	4/24/2017	0	591,464	1,188,335	1,779,799	74,158	39,150	1,631			
485	4/25/2017	0	577,207	1,118,757	1,695,964	70,665	12,600	525			
486	4/26/2017	0	589,212	1,257,163	1,846,375	76,932	45,450	1,894			
487	4/27/2017	0	566,418	1,124,740	1,691,158	70,465	1,800	75			
488	4/28/2017	0	589,826	1,267,470	1,857,296	77,387	58,500	2,438			
489	4/29/2017	0	589,798	1,193,293	1,783,091	74,295	18,000	750			
490	4/30/2017	0	608,402	1,105,129	1,713,531	71,397	42,750	1,781			
491	5/1/2017	0	588,233	988,835	1,577,068	65,711	15,750	656			
492	5/2/2017	0	598,150	1,116,291	1,714,441	71,435	35,550	1,481			
493	5/3/2017	0	593,969	1,124,412	1,718,381	71,599	26,550	1,106			
494	5/4/2017	0	590,031	1,168,138	1,758,169	73,257	17,536	731			
495	5/5/2017	0	569,747	1,009,682	1,579,429	65,810	37,800	1,575			
496	5/6/2017	0	603,925	1,066,350	1,670,275	69,595	36,000	1,500			
497	5/7/2017	0	595,255	1,113,385	1,708,640	71,193	13,500	563			
498	5/8/2017	0	587,790	1,003,609	1,591,399	66,308	31,500	1,313			
499	5/9/2017	0	596,907	1,062,635	1,659,542	69,148	34,500	1,438			
500	5/10/2017	0	581,898	1,022,930	1,604,828	66,868	15,150	631			
501	5/11/2017	0	503,919	871,866	1,375,785	57,324	34,200	1,425			
502	5/12/2017	0	577,733	1,028,721	1,606,454	66,936	24,750	1,031			
503	5/13/2017	0	596,046	1,141,067	1,737,113	72,380	40,500	1,688			
504	5/14/2017	0	587,806	1,167,168	1,754,974	73,124	28,350	1,181			
505	5/15/2017	0	585,124	968,446	1,553,570	64,732	26,100	1,088			
506	5/16/2017	0	585,373	1,120,320	1,705,693	71,071	30,150	1,256			
507	5/17/2017	0	599,181	1,189,305	1,788,486	74,520	22,950	956			
508	5/18/2017	0	586,348	1,129,335	1,715,683	71,487	37,050	1,544			
509	5/19/2017	0	573,661	988,189	1,561,850	65,077	12,600	525			
510	5/20/2017	0	589,551	1,267,474	1,857,025	77,376	14,550	606			
511	5/21/2017	0	601,414	1,284,635	1,886,049	78,585	28,187	1,174			
512	5/22/2017	0	594,673	1,182,587	1,777,260	74,053	24,724	1,030			
513	5/23/2017	0	597,842	1,131,520	1,729,362	72,057	29,924	1,247			
514	5/24/2017	0	592,520	1,116,904	1,709,424	71,226	37,885	1,579			
515	5/25/2017	0	534,994	959,632	1,494,626	62,276	36,313	1,513			
516	5/26/2017	0	583,199	1,012,375	1,595,574	66,482	27,962	1,165			

	A	B	C	D	E	F	G	H	I	J	K
517	5/27/2017	0	581,156	1,180,648	1,761,804	73,409	40,050	1,669			
518	5/28/2017	0	579,808	1,051,625	1,631,433	67,976	27,900	1,163			
519	5/29/2017	0	577,534	1,058,851	1,636,385	68,183	14,400	600			
520	5/30/2017	0	117,416	968,698	1,086,114	45,255	35,100	1,463			
521	5/31/2017	0	582,963	968,008	1,550,971	64,624	4,500	188			
522	6/1/2017	0	582,316	1,063,303	1,645,619	68,567	42,300	1,763			
523	6/2/2017	0	590,407	1,098,320	1,688,727	70,364	36,450	1,519			
524	6/3/2017	0	602,389	1,081,906	1,684,295	70,179	35,100	1,463			
525	6/4/2017	0	595,047	1,073,369	1,668,416	69,517	27,900	1,163			
526	6/5/2017	0	602,040	1,134,007	1,736,047	72,335	22,050	919			
527	6/6/2017	0	584,229	1,110,063	1,694,292	70,596	32,850	1,369			
528	6/7/2017	0	575,817	1,079,731	1,655,548	68,981	26,550	1,106			
529	6/8/2017	0	555,374	1,031,138	1,586,512	66,105	32,367	1,349			
530	6/9/2017	0	598,285	1,082,501	1,680,786	70,033	15,750	656			
531	6/10/2017	0	592,622	1,199,271	1,791,893	74,662	14,100	588			
532	6/11/2017	0	600,245	1,065,344	1,665,589	69,400	33,236	1,385			
533	6/12/2017	0	590,965	1,146,825	1,737,790	72,408	27,600	1,150			
534	6/13/2017	0	593,615	1,127,875	1,721,490	71,729	13,950	581			
535	6/14/2017	0	561,112	1,025,621	1,586,733	66,114	23,704	988			
536	6/15/2017	0	575,265	1,034,750	1,610,015	67,084	39,102	1,629			
537	6/16/2017	0	573,963	998,125	1,572,088	65,504	20,824	868			
538	6/17/2017	0	577,140	1,125,906	1,703,046	70,960	7,200	300			
539	6/18/2017	0	497,862	835,316	1,333,178	55,549	45,343	1,889			
540	6/19/2017	0	567,616	993,904	1,561,520	65,063	0	0			
541	6/20/2017	0	590,751	1,091,997	1,682,748	70,115	41,150	1,715			
542	6/21/2017	0	566,177	1,100,873	1,667,050	69,460	42,130	1,755			
543	6/22/2017	0	568,204	1,042,805	1,611,009	67,125	24,200	1,008			
544	6/23/2017	0	588,752	1,079,091	1,667,843	69,493	27,190	1,133			
545	6/24/2017	284,774	449,058	698,282	1,432,114	59,671	33,750	1,406			
546	6/25/2017	939,252	238,405	30,542	1,208,199	50,342	27,000	1,125			
547	6/26/2017	1,084,019	120,200	22	1,204,241	50,177	31,500	1,313			
548	6/27/2017	1,156,760	46,369	4,215	1,207,344	50,306	29,700	1,238			
549	6/28/2017	1,272,296	44	1,274	1,273,614	53,067	18,450	769			
550	6/29/2017	1,256,865	11,836	1,934	1,270,635	52,943	17,550	731			
551	6/30/2017	1,062,412	127,726	30,425	1,220,563	50,857	24,300	1,013			
552	7/1/2017	1,102,264	135,336	855	1,238,455	51,602	20,700	863			
553	7/2/2017	777,685	138,957	2,726	919,368	38,307	25,650	1,069			
554	7/3/2017	747,915	132,665	5,758	886,338	36,931	0	0			
555	7/4/2017	939,704	57,140	865	997,709	41,571	0	0			
556	7/5/2017	1,103,908	18,945	9,414	1,132,267	47,178	6,750	281			
557	7/6/2017	517,080	242,273	386,667	1,146,020	47,751	31,500	1,313			
558	7/7/2017	0	546,441	761,517	1,307,958	54,498	25,200	1,050			
559	7/8/2017	0	534,591	687,324	1,221,915	50,913	27,450	1,144			
560	7/9/2017	0	580,851	1,002,158	1,583,009	65,959	23,400	975			
561	7/10/2017	0	569,540	918,001	1,487,541	61,981	22,500	938			
562	7/11/2017	0	577,103	1,011,351	1,588,454	66,186	36,000	1,500			
563	7/12/2017	0	587,755	1,102,459	1,690,214	70,426	33,750	1,406			

	A	B	C	D	E	F	G	H	I	J	K
564	7/13/2017	0	585,544	1,085,009	1,670,553	69,606	27,900	1,163			
565	7/14/2017	0	572,412	1,023,391	1,595,803	66,492	13,837	577			
566	7/15/2017	0	551,201	915,801	1,467,002	61,125	54,770	2,282			
567	7/16/2017	0	587,778	1,086,518	1,674,296	69,762	0	0			
568	7/17/2017	0	579,073	1,025,109	1,604,182	66,841	46,858	1,952			
569	7/18/2017	317,893	490,532	528,039	1,336,464	55,686	33,587	1,399			
570	7/19/2017	845,221	426,653	4,507	1,276,381	53,183	7,030	293			
571	7/20/2017	777,854	425,593	3,146	1,206,593	50,275	50,008	2,084			
572	7/21/2017	447,813	481,266	511,532	1,440,611	60,025	39,576	1,649			
573	7/22/2017	0	517,276	1,160,337	1,677,613	69,901	0	0			
574	7/23/2017	0	482,263	1,151,376	1,633,639	68,068	43,585	1,816			
575	7/24/2017	0	421,718	949,394	1,371,112	57,130	24,300	1,013			
576	7/25/2017	0	560,158	822,056	1,382,214	57,592	31,500	1,313			
577	7/26/2017	0	497,097	1,109,057	1,606,154	66,923	22,500	938			
578	7/27/2017	0	320,265	624,940	945,205	39,384	35,550	1,481			
579	7/28/2017	0	351,783	827,912	1,179,695	49,154	0	0			
580	7/29/2017	0	540,230	992,541	1,532,771	63,865	0	0			
581	7/30/2017	0	588,493	1,023,679	1,612,172	67,174	27,495	1,146			
582	7/31/2017	0	575,145	1,007,754	1,582,899	65,954	24,547	1,023			
583	8/1/2017	0	583,445	1,080,039	1,663,484	69,312	52,897	2,204			
584	8/2/2017	0	522,854	1,227,444	1,750,298	72,929	16,650	694			
585	8/3/2017	0	417,790	1,179,213	1,597,003	66,542	50,850	2,119			
586	8/4/2017	0	520,147	1,203,397	1,723,544	71,814	16,200	675			
587	8/5/2017	0	583,730	1,078,552	1,662,282	69,262	30,150	1,256			
588	8/6/2017	0	586,451	1,068,208	1,654,659	68,944	34,200	1,425			
589	8/7/2017	0	544,136	944,441	1,488,577	62,024	10,800	450			
590	8/8/2017	0	547,193	812,506	1,359,699	56,654	35,550	1,481			
591	8/9/2017	0	566,909	951,595	1,518,504	63,271	24,750	1,031			
592	8/10/2017	0	562,600	922,484	1,485,084	61,879	22,950	956			
593	8/11/2017	0	464,176	527,635	991,811	41,325	48,600	2,025			
594	8/12/2017	0	626,308	911,912	1,538,220	64,093	22,050	919			
595	8/13/2017	0	616,582	915,919	1,532,501	63,854	14,850	619			
596	8/14/2017	0	598,328	992,924	1,591,252	66,302	40,050	1,669			
597	8/15/2017	0	575,931	1,043,814	1,619,745	67,489	18,450	769			
598	8/16/2017	0	578,084	1,064,609	1,642,693	68,446	14,400	600			
599	8/17/2017	0	568,878	1,024,518	1,593,396	66,392	38,741	1,614			
600	8/18/2017	0	568,049	1,110,843	1,678,892	69,954	50,098	2,087			
601	8/19/2017	0	596,712	1,070,206	1,666,918	69,455	19,100	796			
602	8/20/2017	0	198,934	205,098	404,032	16,835	45,176	1,882			
603	8/21/2017	0	19,892	7,933	27,825	1,159	0	0			
604	8/22/2017	0	548,703	769,512	1,318,215	54,926	0	0			
605	8/23/2017	0	584,171	1,171,834	1,756,005	73,167	32,318	1,347			
606	8/24/2017	0	597,169	1,066,367	1,663,536	69,314	10,444	435			
607	8/25/2017	0	595,794	1,129,743	1,725,537	71,897	32,608	1,359			
608	8/26/2017	0	597,037	1,110,076	1,707,113	71,130	39,429	1,643			
609	8/27/2017	0	602,115	1,093,654	1,695,769	70,657	30,075	1,253			
610	8/28/2017	0	525,807	864,994	1,390,801	57,950	45,160	1,882			

	A	B	C	D	E	F	G	H	I	J	K
611	8/29/2017	0	392,402	681,241	1,073,643	44,735	0	0			
612	8/30/2017	0	548,797	675,320	1,224,117	51,005	0	0			
613	8/31/2017	0	520,106	640,664	1,160,770	48,365	0	0			
614	9/1/2017	0	531,275	595,248	1,126,523	46,938	0	0			
615	9/2/2017	0	551,523	677,804	1,229,327	51,222	0	0			
616	9/3/2017	0	551,697	665,489	1,217,186	50,716	0	0			
617	9/4/2017	0	555,061	695,623	1,250,684	52,112	0	0			
618	9/5/2017	0	552,778	716,143	1,268,921	52,872	0	0			
619	9/6/2017	0	582,617	926,115	1,508,732	62,864	0	0			
620	9/7/2017	0	569,532	1,021,879	1,591,411	66,309	16,650	694			
621	9/8/2017	0	574,343	1,168,305	1,742,648	72,610	36,450	1,519			
622	9/9/2017	0	579,194	1,162,983	1,742,177	72,591	16,200	675			
623	9/10/2017	0	567,598	1,115,942	1,683,540	70,148	37,800	1,575			
624	9/11/2017	0	585,198	1,128,421	1,713,619	71,401	38,250	1,594			
625	9/12/2017	0	607,148	1,123,866	1,731,014	72,126	36,000	1,500			
626	9/13/2017	0	599,952	1,058,494	1,658,446	69,102	20,250	844			
627	9/14/2017	0	608,428	905,019	1,513,447	63,060	33,300	1,388			
628	9/15/2017	0	600,192	773,916	1,374,108	57,255	31,500	1,313			
629	9/16/2017	0	603,374	720,222	1,323,596	55,150	6,750	281			
630	9/17/2017	0	612,772	602,218	1,214,990	50,625	0	0			
631	9/18/2017	0	589,556	743,437	1,332,993	55,541	0	0			
632	9/19/2017	0	535,878	752,109	1,287,987	53,666	8,215	342			
633	9/20/2017	0	579,769	998,574	1,578,343	65,764	44,258	1,844			
634	9/21/2017	0	538,296	705,954	1,244,250	51,844	26,970	1,124			
635	9/22/2017	0	616,704	1,020,023	1,636,727	68,197	45,884	1,912			
636	9/23/2017	0	282,741	691,602	974,343	40,598	10,506	438			
637	9/24/2017	0	566,692	742,096	1,308,788	54,533	0	0			
638	9/25/2017	0	617,515	1,047,934	1,665,449	69,394	26,400	1,100			
639	9/26/2017	0	620,893	984,408	1,605,301	66,888	28,600	1,192			
640	9/27/2017	0	633,666	1,014,721	1,648,387	68,683	4,551	190			
641	9/28/2017	0	615,835	990,130	1,605,965	66,915	41,842	1,743			
642	9/29/2017	0	627,302	965,821	1,593,123	66,380	40,786	1,699			
643	9/30/2017	0	600,964	818,334	1,419,298	59,137	41,192	1,716			
644	10/1/2017	0	427,089	586,165	1,013,254	42,219	41,670	1,736			
645	10/2/2017	0	24,223	0	24,223	1,009	0	0			
646	10/3/2017	0	0	0	0	0	0	0			
647	10/4/2017	0	0	0	0	0	0	0			
648	10/5/2017	0	0	0	0	0	0	0			
649	10/6/2017	0	11,963	1,279	13,242	552	0	0			
650	10/7/2017	0	129,223	58	129,281	5,387	0	0			
651	10/8/2017	0	137,999	216	138,215	5,759	0	0			
652	10/9/2017	0	152,550	3,612	156,162	6,507	9,000	375			
653	10/10/2017	0	15,437	1,951	17,388	725	450	19			
654	10/11/2017	0	124,939	1,988	126,927	5,289	0	0			
655	10/12/2017	0	166,963	2,010	168,973	7,041	0	0			
656	10/13/2017	0	178,424	3,656	182,080	7,587	0	0			
657	10/14/2017	0	176,956	403	177,359	7,390	0	0			

	A	B	C	D	E	F	G	H	I	J	K
658	10/15/2017	0	107,279	1,978	109,257	4,552	0	0			
659	10/16/2017	0	169,131	7,667	176,798	7,367	0	0			
660	10/17/2017	0	374,675	450,817	825,492	34,396	0	0			
661	10/18/2017	0	302,583	507,465	810,048	33,752	0	0			
662	10/19/2017	0	593,455	40,907	634,362	26,432	0	0			
663	10/20/2017	0	281,454	636,565	918,019	38,251	0	0			
664	10/21/2017	0	355,437	616,941	972,378	40,516	0	0			
665	10/22/2017	0	363,975	618,749	982,724	40,947	0	0			
666	10/23/2017	0	198,702	606,315	805,017	33,542	0	0			
667	10/24/2017	0	450,954	802,978	1,253,932	52,247	0	0			
668	10/25/2017	0	512,522	819,130	1,331,652	55,486	0	0			
669	10/26/2017	0	508,284	773,923	1,282,207	53,425	0	0			
670	10/27/2017	0	503,732	761,722	1,265,454	52,727	0	0			
671	10/28/2017	0	498,643	776,619	1,275,262	53,136	0	0			
672	10/29/2017	0	509,786	771,779	1,281,565	53,399	0	0			
673	10/30/2017	0	413,476	827,136	1,240,612	51,692	0	0			
674	10/31/2017	0	575,594	1,154,289	1,729,883	72,078	19,450	810			
675	11/1/2017	0	568,770	1,071,886	1,640,656	68,361	27,751	1,156			
676	11/2/2017	0	561,023	1,095,898	1,656,921	69,038	25,296	1,054			
677	11/3/2017	0	579,093	1,131,921	1,711,014	71,292	66,714	2,780			
678	11/4/2017	0	564,878	1,195,295	1,760,173	73,341	28,075	1,170			
679	11/5/2017	0	567,300	1,157,454	1,724,754	71,865	27,642	1,152			
680	11/6/2017	0	491,690	775,788	1,267,478	52,812	30,656	1,277			
681	11/7/2017	0	570,940	1,113,211	1,684,151	70,173	19,794	825			
682	11/8/2017	0	586,996	1,222,894	1,809,890	75,412	23,650	985			
683	11/9/2017	0	604,338	1,208,919	1,813,257	75,552	44,000	1,833			
684	11/10/2017	0	600,283	1,047,601	1,647,884	68,662	13,200	550			
685	11/11/2017	0	622,149	1,081,261	1,703,410	70,975	22,708	946			
686	11/12/2017	0	625,977	1,045,842	1,671,819	69,659	42,814	1,784			
687	11/13/2017	0	603,195	928,394	1,531,589	63,816	24,750	1,031			
688	11/14/2017	0	613,912	1,216,471	1,830,383	76,266	31,160	1,298			
689	11/15/2017	0	627,177	1,200,560	1,827,737	76,156	31,170	1,299			
690	11/16/2017	0	624,458	1,117,122	1,741,580	72,566	41,400	1,725			
691	11/17/2017	0	581,753	713,967	1,295,720	53,988	0	0			
692	11/18/2017	0	473,570	649,353	1,122,923	46,788	0	0			
693	11/19/2017	0	580,577	730,128	1,310,705	54,613	0	0			
694	11/20/2017	0	549,421	613,211	1,162,632	48,443	0	0			
695	11/21/2017	0	563,905	827,313	1,391,218	57,967	8,100	338			
696	11/22/2017	0	624,619	1,017,638	1,642,257	68,427	30,600	1,275			
697	11/23/2017	0	627,586	1,028,574	1,656,160	69,007	34,650	1,444			
698	11/24/2017	0	610,072	939,263	1,549,335	64,556	23,850	994			
699	11/25/2017	0	622,695	999,108	1,621,803	67,575	27,900	1,163			
700	11/26/2017	0	604,038	886,050	1,490,088	62,087	44,550	1,856			
701	11/27/2017	0	610,606	919,372	1,529,978	63,749	19,110	796			
702	11/28/2017	0	585,094	842,254	1,427,348	59,473	29,250	1,219			
703	11/29/2017	0	628,023	1,021,740	1,649,763	68,740	17,100	713			
704	11/30/2017	0	625,132	1,021,420	1,646,552	68,606	42,300	1,763			

	A	B	C	D	E	F	G	H	I	J	K
705	12/1/2017	0	621,911	1,036,240	1,658,151	69,090	22,050	919			
706	12/2/2017	0	627,525	1,050,910	1,678,435	69,935	22,500	938			
707	12/3/2017	0	629,160	1,092,328	1,721,488	71,729	49,950	2,081			
708	12/4/2017	0	629,204	1,084,058	1,713,262	71,386	10,800	450			
709	12/5/2017	0	574,574	898,566	1,473,140	61,381	54,900	2,288			
710	12/6/2017	0	562,070	901,198	1,463,268	60,970	18,000	750			
711	12/7/2017	0	563,240	913,556	1,476,796	61,533	45,450	1,894			
712	12/8/2017	0	535,618	820,675	1,356,293	56,512	26,100	1,088			
713	12/9/2017	0	624,066	1,052,941	1,677,007	69,875	4,950	206			
714	12/10/2017	0	557,004	915,932	1,472,936	61,372	39,308	1,638			
715	12/11/2017	0	630,721	1,076,645	1,707,366	71,140	39,600	1,650			
716	12/12/2017	0	615,928	998,418	1,614,346	67,264	6,183	258			
717	12/13/2017	0	610,746	1,016,355	1,627,101	67,796	3,200	133			
718	12/14/2017	0	624,628	1,150,252	1,774,880	73,953	73,956	3,082			
719	12/15/2017	0	595,151	910,853	1,506,004	62,750	10,213	426			
720	12/16/2017	0	614,703	1,000,740	1,615,443	67,310	38,900	1,621			
721	12/17/2017	0	619,959	1,026,352	1,646,311	68,596	15,330	639			
722	12/18/2017	0	609,717	972,018	1,581,735	65,906	26,124	1,089			
723	12/19/2017	0	620,314	1,038,002	1,658,316	69,097	20,752	865			
724	12/20/2017	0	626,197	1,093,445	1,719,642	71,652	46,554	1,940			
725	12/21/2017	0	290,346	287,862	578,208	24,092	31,106	1,296			
726	12/22/2017	0	229,407	0	229,407	9,559	0	0			
727	12/23/2017	0	182,162	0	182,162	7,590	0	0			
728	12/24/2017	0	194,317	0	194,317	8,097	0	0			
729	12/25/2017	0	194,133	0	194,133	8,089	0	0			
730	12/26/2017	0	194,458	0	194,458	8,102	0	0			
731	12/27/2017	0	269,963	0	269,963	11,248	550	23			
732	12/28/2017	0	237,521	0	237,521	9,897	0	0			
733	12/29/2017	0	331,019	180,708	511,727	21,322	0	0			
734	12/30/2017	0	429,837	711,562	1,141,399	47,558	0	0			
735	12/31/2017	0	395,963	715,412	1,111,375	46,307	0	0			
736											
737			Maximum:		2,196,113	91,505		3,082			
738			Average		1,333,014	55,542		932			

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Changes in Potential To Emit for Criteria Air Pollutants												
2	Emission Point	CO		NOx		SO_2		PM2.5		PM10		VOC	
3		lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
4	*Point Sources*												
5	Boiler 1A	7.37	32.01	1.89	8.05	0.06	0.25	0.74	3.23	0.74	3.23	0.54	2.34
6	Boiler 2A	7.37	32.01	1.89	8.05	0.06	0.25	0.74	3.23	0.74	3.23	0.54	2.34
7	Kipper Boiler	8.91	-136.91	-3.69	-79.19	-46.28	-210.72	-2.73	-51.39	-2.73	-51.39	0.47	-6.32
8	Boiler 1	-4.28	-18.76	-5.10	-22.33	-0.12	-0.54	-0.39	-1.70	-0.39	-1.70	-0.28	-1.23
9	Boiler 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	7020	0.14	0.32	0.05	0.10	0.00	0.00	0.04	0.12	0.04	0.12	0.00	0.01
11	7101	0.48	1.06	0.16	0.37	0.01	0.03	0.20	0.84	0.20	0.84	0.01	0.02
12	7102	0.48	1.05	0.16	0.37	0.01	0.03	0.20	0.84	0.20	0.84	0.01	0.02
13	7019	0.34	0.76	0.12	0.27	0.01	0.06	0.11	0.46	0.11	0.46	0.00	0.01
14	7001	0.06	0.13	0.02	0.04	0.00	0.01	0.02	0.07	0.02	0.07	0.00	0.00
15	7027	0.05	0.10	0.02	0.03	0.00	0.00	0.01	0.01	0.01	0.01	0.00	0.00
16	7006	0.04	0.08	0.01	0.03	0.00	0.00	0.01	0.03	0.01	0.03	0.00	0.00
17	5034	0.02	0.04	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	5037	0.19	0.42	0.06	0.14	0.00	0.00	0.01	0.02	0.01	0.02	0.01	0.01
19	4000	0.50	1.10	0.16	0.36	0.00	0.00	0.02	0.04	0.02	0.04	0.01	0.03
20	228	0.30	0.65	0.10	0.21	0.00	0.00	0.01	0.03	0.01	0.03	0.01	0.02
21	234	0.44	0.96	0.14	0.31	0.00	0.00	0.02	0.04	0.02	0.04	0.01	0.03
22	613/614	0.00	0.00	0.00	0.00	-0.13	-0.56	-0.85	-3.74	-0.85	-3.74	0.00	0.00
23	615/616	0.00	0.00	0.00	0.00	-0.04	-0.16	-0.24	-1.05	-0.24	-1.05	0.00	0.00
24	638	0.00	0.00	0.00	0.00	-0.17	-0.74	-1.09	-4.80	-1.09	-4.80	0.00	0.00
25	M33	0.12	0.27	0.04	0.09	0.00	0.00	0.00	0.01	0.00	0.01	0.00	0.01
26	M44	0.03	0.06	0.01	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	M56	0.04	0.10	0.01	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
28	M62	0.06	0.12	0.02	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	M86	0.12	0.26	0.04	0.09	0.00	0.00	0.00	0.01	0.00	0.01	0.00	0.01
30	Flake North	0.33	0.72	0.27	0.59	0.00	0.01	0.49	0.53	0.49	2.06	0.03	0.06
31	Flake South	0.33	0.72	0.27	0.59	0.00	0.01	0.49	0.53	0.49	2.06	0.03	0.06
32	P4A	1.94	7.76	0.38	1.41	0.01	0.02	0.43	1.84	0.43	1.84	0.06	0.23
33	P4BCD	2.16	8.72	0.38	1.41	0.01	0.03	1.74	7.59	1.74	7.59	0.06	0.26
34	707	0.02	0.05	0.01	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	725	0.02	0.04	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	8	0.04	0.09	0.01	0.03	0.00	0.00	0.00	0.01	0.00	0.01	0.00	0.00
37	5001	0.01	0.03	0.00	0.01	0.00	0.00	0.00	0.01	0.00	0.01	0.00	0.00
38	5000	0.01	0.03	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
39	432	0.01	0.02	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40	322	0.01	0.02	0.00	0.01	0.00	0.00	0.00	0.01	0.00	0.01	0.00	0.00
41	572	0.01	0.03	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	*Fugitive Sources*									0.00			
43	Main	2.88	6.32	0.94	2.05	0.01	0.02	0.11	0.24	0.11	0.24	0.09	0.19
44	Old Boilerhouse	0.78	1.71	0.15	0.33	0.00	0.00	0.02	0.05	0.02	0.05	0.02	0.04
45	New Boilerhouse	0.12	0.26	0.10	0.21	0.00	0.00	0.01	0.03	0.01	0.03	0.01	0.02
46	Flake	0.27	0.59	0.22	0.49	0.00	0.00	0.03	0.06	0.03	0.06	0.02	0.05
47	Receiving	0.46	1.01	0.18	0.40	0.00	0.00	0.02	0.05	0.02	0.05	0.02	0.04
48	Heaters	-8.01	-17.54	-1.54	-3.37	-0.07	-0.16	-0.23	-0.50	-0.23	-0.50	-0.17	-0.36
49	RX-OB11	-0.94	-2.05	-1.08	-2.36	-0.03	-0.07	-0.10	-0.22	-0.10	-0.22	-0.07	-0.31
50	Woodpile	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.02	0.00	-9.95
51	*Δ PTE - Point Sources:*	*27.69*	*-65.93*	*-2.55*	*-78.80*	*-46.58*	*-211.99*	*0.00*	*-43.17*	*0.00*	*-40.12*	*1.53*	*-2.08*
52	*Δ PTE - Fugitive*	*-4.43*	*-9.71*	*-1.03*	*-2.25*	*-0.09*	*-0.20*	*-0.13*	*-0.29*	*-0.13*	*-0.31*	*-0.09*	*-10.29*
53	*Δ PTE for All Units:*	*23.26*	*-75.64*	*-3.58*	*-81.05*	*-46.66*	*-212.18*	*-0.14*	*-43.46*	*-0.13*	*-40.42*	*1.44*	*-12.37*

	A	B	C	D	E	F	G	H	I	J	K	L	M
1													
2													
3													
4			**CO**		**NOx**		**SO_2**		**PM2.5**		**PM10**		**Pb**
5			lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/month
6	PTE for New Units and Increase in Emissions for Existing uniots		36.48	99.62	7.83	26.20	0.18	0.76	5.50	19.94	5.50	23.00	
7	Associated Emissions Increases												
8		Process A Burners	0.20	0.87	0.04	0.17	0.00	0.01	0.01	0.02	0.01	0.02	
9		Kipper Boiler Steam Generation	0.70	0.00	0.25	0.00	0.03	0.00	0.16	0.00	0.16	0.00	
10		Materials Transport and Packaging	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.02	
11		*Total Emissions Increase*	37.39	100.49	8.12	26.37	0.21	0.77	5.66	19.98	5.67	23.04	
12	Threshold Comparison												
13	Level 1	Threshold Value	15	-	0.2	1.2			0.054	0.35	0.22		
14		% of Threshold	249%		4059%	2197%			10489%	5709%	2575%		
15	Level II	Threshold Value	175	-	-	-	0.21	1.2					
16		% of Threshold	21%				100%	64%					
17	Level II Case-by-Case	Threshold Value	-	-	2.4	14	2.5	14	0.63	4.1	2.6		
18		% of Threshold			338%	188%	8%	5%	899%	487%	218%		

	A	B	C	D
1				
2	**Parameter**	**Value**	**Units**	**Discussion/Basis**
3				
4	moisture content of product	7%		
5	moisute content of feed	80%		
6	total flake production (finsished product)	12,000	lb/hr	
7				
8	Process B Process Weight Preproject	76,000	lb/hr	from Dec 2014 PTC application for addition of new production line
9	Process wight for drum dryers	55,800	lb/hr	
10	Net change in process weight forf replacement belt dryer	-9,625	lb/hr	No change in production rate
11	Process weight post project	122,175	lb/hr	
12	Allowable emissions	20.57	lb/hr	IDAPA 58.01.01.701
13	postproject process B emissions	9.01	lb/hr	sum of process B PM10 emissions from Emissions Summary - post-project
14				
15				
16	Process A Process Weight input	24,917	lb/hr	Based on 65 tons/day output at 8% moisture and 20% solids in raw potato
17	Allowable emission	13.82	lb/hr	IDAPA 58.01.01.701
18	Actual PM emissions	6.51	lb/hr	sum of process B PM10 emissions from Emissions Summary - post-project

	A	B	C	D	E	F	G
1							
2							
3	Table 26						
4	Results of Significant Impact Analysis						
5	Pollutant	Averaging Period	Maximum Modeled Concentration, $\mu g/m^3$	Significant Contribution Level, $\mu g/m^3$	Impact Percentage of Significant Contribution Level	Cumulative NAAQS Analysis Required	
6	$PM_{2.5}$	24-hour	0.27	1.2	23%	No	
7		Annual	0.00	0.3	0%	No	
8	PM_{10}	24-hour	0.43	5	9%	No	
9							
10	Table 27						
11	Results of Cumulative Impacts Analysis for NO2						
12	Averaging Period	Time Period	Rank	Maximum Modeled Concentration, $\mu g/m^3$	NAAQS	Impact Percentage of NAAQS	
13	1-hour	2011-2012; 2014-2016 (Five Years)	Highest 8th High Max Daily Hour Averaged Over 5 year	143	188	76.1%	
14	Annual	2011	Maximum Annual Average	7.39			
15		2012	Maximum Annual Average	7.85			
16		2014	Maximum Annual Average	8.30			
17		2015	Maximum Annual Average	9.40			
18		2016	Maximum Annual Average	8.35			
19			*Maximum Annual*	9.40	100	9.4%	
20							
21							
22							
23							
24							
25							
26							
27							
28		Table 27					
29		Results of Cumulative Impact Analysis for 1-hour and Annual NO2 Standard					
30							

	A	B	C	D	E	F	G
31		Rank	Modeled Impact, with Background*, µg/m^3	NAAQS, µg/m3	Impact Percentage of NAAQS		
32		1st Highest	246.2	-	-		
33		2nd Highest	226.6	-	-		
34		3rd Highest	211.7	-	-		
35		4th Highest	204.4	-	-		Chromium(VI)
36		5th Highest	199.2	-	-		
37		6th Highest	192.1	-	-		
38		7th Highest	184.3	-	-		
39		8th Highest	181.3	188	96%		
40		* Background = 14 µg/m3					

	A	B	C	D	E	F	G	H	I	J	K	L	M
1				Receptor Location		Modeled Impact							
2	Pollutant	Year	Group	East (X)	North (Y)	µg/m^3	% of AAAC			Elev	Hill	Flag	Time
3	Formaldehyde	2011	ALL	436765	4854094	2.2E-03				1481	1481.01	0	1 YEARS
4	Formaldehyde	2012	ALL	436780	4854075	2.2E-03				1481	1481.02	0	1 YEARS
5	Formaldehyde	2014	ALL	436765	4854094	2.3E-03				1481	1481.01	0	1 YEARS
6	Formaldehyde	2015	ALL	436765	4854094	2.6E-03				1481	1481.01	0	1 YEARS
7	Formaldehyde	2016	ALL	436765	4854094	2.3E-03				1481	1481.01	0	1 YEARS
8				***Formaldehyde Max***		*2.6E-03*	*3.3%*						
9	Arsenic	2011	ALL	436765	4854094	5.9E-06				1481	1481.01	0	1 YEARS
10	Arsenic	2012	ALL	436780	4854075	5.8E-06				1481	1481.02	0	1 YEARS
11	Arsenic	2014	ALL	436765	4854094	6.1E-06				1481	1481.01	0	1 YEARS
12	Arsenic	2015	ALL	436765	4854094	6.8E-06				1481	1481.01	0	1 YEARS
13	Arsenic	2016	ALL	436765	4854094	6.2E-06				1481	1481.01	0	1 YEARS
14					***Arsenic Max***	***6.8E-06***	*3.0%*						
15	Cadmium	2011	ALL	436765	4854094	3.3E-05				1481	1481.01	0	1 YEARS
16	Cadmium	2012	ALL	436780	4854075	3.2E-05				1481	1481.02	0	1 YEARS
17	Cadmium	2014	ALL	436765	4854094	3.4E-05				1481	1481.01	0	1 YEARS
18	Cadmium	2015	ALL	436765	4854094	3.7E-05				1481	1481.01	0	1 YEARS
19	Cadmium	2016	ALL	436765	4854094	3.4E-05				1481	1481.01	0	1 YEARS
20					***Cadmium Max***	*3.7E-05*	*6.7%*						
21	Chromium(VI)	2011	ALL	436765	4854094	2.1E-06				1481	1481.01	0	1 YEARS
22	Chromium(VI)	2012	ALL	436780	4854075	2.0E-06				1481	1481.02	0	1 YEARS
23	Chromium(VI)	2014	ALL	436765	4854094	2.1E-06				1481	1481.01	0	1 YEARS
24	Chromium(VI)	2015	ALL	436765	4854094	2.4E-06				1481	1481.01	0	1 YEARS
25	Chromium(VI)	2016	ALL	436765	4854094	2.2E-06				1481	1481.01	0	1 YEARS
26				***Chromium(VI) Max***		*2.4E-06*	*2.9%*						
27	Nickel	2011	ALL	436765	4854094	6.2E-05				1481	1481.01	0	1 YEARS
28	Nickel	2012	ALL	436780	4854075	6.1E-05				1481	1481.02	0	1 YEARS
29	Nickel	2014	ALL	436765	4854094	6.4E-05				1481	1481.01	0	1 YEARS
30	Nickel	2015	ALL	436765	4854094	7.2E-05				1481	1481.01	0	1 YEARS
31	Nickel	2016	ALL	436765	4854094	6.5E-05				1481	1481.01	0	1 YEARS
32					***Nickel Max***	*7.2E-05*	*1.7%*						

	N	O	P	Q	R	S	T
1							
2	Met File	Sources	Groups	Receptors			Conc/Dep
3	DEQ KRXE2011_adj u.SFC	9	1	2728			2218.29785
4	DEQ KRXE2012_adj u.SFC	9	1	2728			2179.25067
5	DEQ KRXE2014_adj u.SFC	9	1	2728			2284.07171
6	DEQ KRXE2015_adj u.SFC	9	1	2728			2554.20849
7	DEQ KRXE2016_adj u.SFC	9	1	2728			2323.41605
8							
9	DEQ KRXE2011_adj u.SFC	9	1	2728			5.9134
10	DEQ KRXE2012_adj u.SFC	9	1	2728			5.80933
11	DEQ KRXE2014_adj u.SFC	9	1	2728			6.08885
12	DEQ KRXE2015_adj u.SFC	9	1	2728			6.80899
13	DEQ KRXE2016_adj u.SFC	9	1	2728			6.19373
14							
15	DEQ KRXE2011_adj u.SFC	9	1	2728			32.56622
16	DEQ KRXE2012_adj u.SFC	9	1	2728			31.99174
17	DEQ KRXE2014_adj u.SFC	9	1	2728			33.53264
18	DEQ KRXE2015_adj u.SFC	9	1	2728			37.49876
19	DEQ KRXE2016_adj u.SFC	9	1	2728			34.10956
20							
21	DEQ KRXE2011_adj u.SFC	9	1	2728			2.06762
22	DEQ KRXE2012_adj u.SFC	9	1	2728			2.03121
23	DEQ KRXE2014_adj u.SFC	9	1	2728			2.12887
24	DEQ KRXE2015_adj u.SFC	9	1	2728			2.38066
25	DEQ KRXE2016_adj u.SFC	9	1	2728			2.16563
26							
27	DEQ KRXE2011_adj u.SFC	9	1	2728			62.13492
28	DEQ KRXE2012_adj u.SFC	9	1	2728			61.04034
29	DEQ KRXE2014_adj u.SFC	9	1	2728			63.978
30	DEQ KRXE2015_adj u.SFC	9	1	2728			71.54477
31	DEQ KRXE2016_adj u.SFC	9	1	2728			65.07937
32							

	A	B	C	D
1				
2	**Parameter**	**Value**	**Units**	**Discussion**
3	**General Parameters**			
4	barometric pressure - standard conditions	14.7	psi	
5	barometric pressure at Rexburg @ 20 C	12.33	psi	
6	NG, HHV	1020	BTU/scf	
7	FW, NO2	46		
8	FW, CO	28		
9	*Stoichiometric NG combustion parameters*			
10	Fd, dry exhaust gas factor	8710	dscf/MMBtu	From Table 19-2, EPA Test Method 19
11	Fw, wet exhaust gas factor	10610	wscf/MMBtu	From Table 19-2, EPA Test Method 19
12				
13	amu air flow per MMBTUh	9000	cfm/MMBtuh	Based on data for Reyco VentPak 800 for Rexburg - 80,000 cfm makeup air supply @ 8.8 MMBtuh burner rating
14				
15	**Generic Bar Burner Emission Factors**			
16	PM10 - primary	7.6000	lb/MMscf	AP-42. Table 1.4-2
17	PM2.5 - primary	7.6000	lb/MMscf	
18	VOC	5.8	lb/MMscf	AP-42, Section 1.4 (7/98).for small boilers < 100 MMBtu
19	Pb	2.71E-04	lb/MMscf	
20	SO_2	0.6	lb/MMscf	
21	NOx	0.05	lb/MMBtu	Based on results of emission measurements of similar bar burners completed at the BAF Blackfoot Plant.
22	CO	0.26	lb/MMBtu	
23	HCOH	7.50E-02	lb/MMscf	AP-42, Section 1.4
24	As	2.00E-04	lb/MMscf	AP-42, Section 1.4
25	Cd	1.10E-03	lb/MMscf	AP-42, Section 1.4
26	Cr(VI)	7.00E-05	lb/MMscf	AP-42, Section 1.4. 5% of chromium assumed to be Chromium (VI). See "AB 2588 Combustion Emission Factors", Ventura County APCD, May 17, 2001
27	Ni	2.10E-03	lb/MMscf	AP-42, Section 1.4

	A	B	C	D	E	F	G	H
1					Burner Rating,	Burner Emissions, ppm @ 3% Oxygen		
2	**AMU**	**Associated Building**	**Status**	**Air Supply, cfm**	**MMBtuh**	**NOx**	**CO**	**Discussion**
3	Reyco - Boiler Room North	New Boilerhouse	New	35,000	2.5	50	100	Reyco drawing no. 190489-001A01 Rev 1 (4-26-19). Attached to 6-15-19 email from Scott Holdeman.
4	Reyco - Boiler Room South	New Boilerhouse	New	35,000	2.5	50	100	
5	Reyco - Flake South	Flake	New	40,000	2.9	50	100	Reyco drawing no. 190488-002A01 Rev 3 (5-29-19). Attached to 6-15-19 email from Scott Holdeman.
6	Reyco - Flake North #1	Flake	New	68,000	4.9	50	100	
7	Reyco - Flake North #2	Flake	New	68,000	4.9	50	100	
8	Reyco - Slab	Receiving	New	18,000	1.3	50	100	Reyco drawing no. 190489721-001A01 Rev 0 (5-24-19). Attached to 6-15-19 email from Scott Holdeman.
9	Reyco - Potato Cleaning	Receiving	New	10,000	0.7	50	100	
10	King DFOC - Receiving	Receiving	Existing	12,000	1.2	-	-	Equipment Inspection by Ron Gibb and Steve Brockett, BAF., 2003 and 2019
11	Aerovent G500 - Main NW	Main	Existing	30,000	3.0	-	-	Equipment Inspection by Ron Gibb and Steve Brockett, BAF., 2003 and 2019
12	Aerovent G503 - Main - North	Main	Existing	30,000	3.0	-	-	
13	Reyco VentPak 800 Main - Shop	Main	Existing	80,000	8.8	-	-	
14	Reyco VentPak 800 - Main - Proctor	Main	Existing	80,000	8.8	-	-	
15	Reyco VentPak - West	Main	Existing	120,000*	13.3	70	100	Equipment Specifications
16	Aerovent - Boilerhouse	Old Boilerhouse	Existing	30,000	3.0	-	-	Equipment Inspection by Ron Gibb and Steve Brockett, BAF., 2003 and 2019
17								
18	* Rated air supply not available. Air supply estimated at 9000 cfm/MMBtu, based on Reyco VentPak 800 units.							

	A	B	C	D	E	F	G
1							
2							
3	**Stack**	**Stack ID**	**Temp, deg F**	**Stack Discharge, acfm**	**Associated Building**	**Process Air Source**	
4	Boiler 1A	BLR1A	306	34,480	New Boilerhouse	Room	
5	Boiler 2A	BLR2A	306	34,480	New Boilerhouse	Room	
6	Kipper Boiler	Kipper	129	26,238	Old Boilerhouse	Outside	
7	Boiler 2	Boiler2	450	20,446	Old Boilerhouse	Outside	
8	Flake North	FLK_N	115	68,000	Flake	Room	
9	Flake South	FLK_S	115	68,000	Flake	Room	
10	P4A	P4A	145	18,710	Main	Room	
11	P4BCD	P4BCD	145	18,713	Main	Room	
12	7020	7020	97	7,288	Main	Room	
13	7101	7101	174	27,572	Main	Room	
14	7102	7102	153	26,443	Main	Room	
15	7019	7019	135	18,743	Main	Room	
16	7001	7001	90	2,919	Main	Room	
17	7027	7027	85	2,281	Main	Room	
18	7006	7006	90	1,891	Main	Room	
19	5037	5037	130	10,157	Main	Room	
20	5034	5034	150	1,087	Main	Room	
21	4000	4000	147	27,666	Main	Room	
22	228	228	133	15,890	Main	Room	
23	234	234	157	24,532	Main	Room	
24	M33	M33	160	7,000	Main	Room	
25	M44	M44	293	1,844	Main	Room	
26	M56	M56	170	2,500	Main	Room	
27	M62	M62	140	3,000	Main	Room	
28	M86	M86	137	6,500	Main	Room	
29	707	707	90	1118	Main	Room	
30	725	725	90	796	Main	Room	
31	8	8	81	2059	Main	Room	
32	5001	5000	76	605	Main	Room	
33	5000	5001	80	618	Main	Room	
34	432	432	80	466	Main	Room	
35	322	322	180	426	Main	Room	
36	572	572	90	691	Main	Room	
37							
38							
39							
40	*Retired Stacks*						
41	Boiler1	Boiler1	500	19,972		Outside	
42	613/614	613/614	140	11,041		Room	
43	615/616	615/616	192	9,929		Room	
44	638	638	162	2,599		Room	

	A	B	C	D
1				
2	**Parameter**	**Value**	**Units**	**Discussion**
3	NOx emissions conversion - ppm to lb/MMBtu			
4	unit ppm	1	ppmv @ 3% O2	
5	FW, formula weight	46	-	NOx as NO2
6	E, emissions	0.00000012	lb/dscf	=PPM*FW/(385.1*10^6)
7	Fa, Fd adjusted to 3% O2	10,170	dscf/MMBtu @ 3% O2	=Fd*(20.9/(20.9-3))
8	heat rate emission factor	0.00121	(lb/MMBtu)/ppmv	=E*Fa
9	fuel rate emission factor	1.24	(lb/MMscf NG)/ppm	
10				
11	CO emissions conversion - ppm to lb/MMBtu			
12	PPM, stack gas concentration	1	ppmv @ 3% O2	estimate for uncontrolled burner
13	FW, formula weight	28	-	
14	E, emissions	0.00000007	lb/dscf	=PPM*FW/(385.1*10^6)
15	Fa, Fd adjusted to 3% O2	10,170	dscf/MMBtu @ 3% O2	=Fd*(20.9/(20.9-3))
16	heat rate emission factor	0.00074	(lb/MMBtu)/ppmv	=E*Fa
17	fuel rate emission factor	0.75	(lb/MMscf NG)/ppm	

	A	B	C	D	E
1					
2					
3		NG Combustion			
4		MMBtu		MMscf*	
5	AMU	Hourly	Annual†	Hourly	Annual†
6	*New AMUs*				
7	Reyco - Boiler Room North	2.50	10,950	0.0025	10.74
8	Reyco - Boiler Room South	2.50	10,950	0.0025	10.74
9	Reyco - Flake South	2.86	12,527	0.0028	12.28
10	Reyco - Flake North #1	4.86	21,296	0.0048	20.88
11	Reyco - Flake North #2	4.86	21,296	0.0048	20.88
12	Reyco - Slab	1.29	5,637	0.0013	5.53
13	Reyco - Potato Cleaning	0.72	3,132	0.0007	3.07
14	*Existing AMUs*				
15	King DFOC - Receiving	1.20	5,256	0.0012	5.15
16	Aerovent G500 - Main NW	3.00	13,140	0.0029	12.88
17	Aerovent G503 - Main - North	3.00	13,140	0.0029	12.88
18	Reyco VentPak 800 Main - Shop	8.80	38,544	0.0086	37.79
19	Reyco VentPak 800 - Main - Proctor	8.80	38,544	0.0086	37.79
20	Reyco VentPak - West	13.30	58,254	0.0130	57.11
21	Aerovent - Boilerhouse	3.00	13,140	0.0029	12.88
22	Notes:				
23	* Based on NG HHV = 1020 Btu/scf				
24	† Maximum Firing Assumed to be 50% of Maximum Hourly Firing Rate				

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W
1																							
2			Criteria Air Pollutants																				
3			PM10		PM2.5		SO2		NOx		CO		VOC		Pb								1
4			Hourly,	Annual,	Hourly,	Annual,	Hourly,	Annual,	Hourly,	Annual,	Hourly,	Annual,	Hourly,	Annual,	Hourly,	Annual,	Toxic Air Pollutants, lb/hr (annual average)						2
5	AMU	Building	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	HCOH	As	Cd	Cr(VI)	Ni		3
6	*New AMUs*																						4
7	Reyco - Boiler Room North	New Boilerhouse	0.019	0.041	0.019	0.041	0.001	0.003	0.152	0.33	0.185	0.40	0.014	0.03	6.6E-07	1.5E-06	9.19E-05	2.45E-07	1.35E-06	8.58E-08	2.57E-06		5
8	Reyco - Boiler Room South	New Boilerhouse	0.019	0.041	0.019	0.041	0.001	0.003	0.152	0.33	0.185	0.40	0.014	0.03	6.6E-07	1.5E-06	9.19E-05	2.45E-07	1.35E-06	8.58E-08	2.57E-06		6
9	Reyco - Flake South	Flake	0.021	0.047	0.021	0.047	0.002	0.004	0.174	0.38	0.211	0.46	0.016	0.04	7.6E-07	1.7E-06	1.05E-04	2.80E-07	1.54E-06	9.81E-08	2.94E-06		7
10	Reyco - Flake North #1	Flake	0.036	0.079	0.036	0.079	0.003	0.006	0.295	0.65	0.360	0.79	0.028	0.06	1.3E-06	2.8E-06	1.79E-04	4.77E-07	2.62E-06	1.67E-07	5.01E-06		8
11	Reyco - Flake North #2	Flake	0.036	0.079	0.036	0.079	0.003	0.006	0.295	0.65	0.360	0.79	0.028	0.06	1.3E-06	2.8E-06	1.79E-04	4.77E-07	2.62E-06	1.67E-07	5.01E-06		9
12	Reyco - Slab	Receiving	0.010	0.021	0.010	0.021	0.001	0.002	0.078	0.17	0.095	0.21	0.007	0.02	3.4E-07	7.5E-07	4.73E-05	1.26E-07	6.94E-07	4.42E-08	1.32E-06		10
13	Reyco - Potato Cleaning	Receiving	0.005	0.012	0.005	0.012	0.000	0.001	0.043	0.10	0.053	0.12	0.004	0.01	1.9E-07	4.2E-07	2.63E-05	7.01E-08	3.86E-07	2.45E-08	7.36E-07		11
14	*Existing AMUs*																						12
15	King OFOC - Receiving	Receiving	0.009	0.020	0.009	0.020	0.001	0.002	0.060	0.131	0.312	0.683	0.007	0.01	3.2E-07	7.0E-07	4.41E-05	1.18E-07	6.47E-07	4.12E-08	1.24E-06		13
16	Aerovent G500 - Main NW	Main	0.022	0.049	0.022	0.049	0.002	0.004	0.150	0.329	0.780	1.708	0.017	0.04	8.0E-07	1.7E-06	1.10E-04	2.94E-07	1.62E-06	1.03E-07	3.09E-06		14
17	Aerovent G503 - Main - North	Main	0.022	0.049	0.022	0.049	0.002	0.004	0.150	0.329	0.780	1.708	0.017	0.04	8.0E-07	1.7E-06	1.10E-04	2.94E-07	1.62E-06	1.03E-07	3.09E-06		15
18	Reyco VentPak 800 Main - Shop	Main	0.066	0.144	0.066	0.144	0.005	0.011	0.440	0.964	2.288	5.011	0.050	0.11	2.3E-06	5.1E-06	3.24E-04	8.63E-07	4.75E-06	3.02E-07	9.06E-06		16
19	Reyco VentPak 800 - Main - Proctor	Main	0.066	0.144	0.066	0.144	0.005	0.011	0.440	0.964	2.288	5.011	0.050	0.11	2.3E-06	5.1E-06	3.24E-04	8.63E-07	4.75E-06	3.02E-07	9.06E-06		17
20	Reyco VentPak - West	Main	0.099	0.217	0.099	0.217	0.008	0.017	1.131	2.48	0.983	2.15	0.076	0.17	3.5E-06	7.7E-06	4.89E-04	1.30E-06	7.17E-06	4.56E-07	1.37E-05		18
21	Aerovent - Boilerhouse	Old Boilerhouse	0.022	0.049	0.022	0.049	0.002	0.004	0.150	0.329	0.780	1.708	0.017	0.04	8.0E-07	1.7E-06	1.10E-04	2.94E-07	1.62E-06	1.03E-07	3.09E-06		19
22	*Totals:*																						20
23	*New AMUs:*		*0.146*	*0.320*	*0.146*	*0.320*	*0.012*	*0.025*	*1.190*	*2.605*	*1.448*	*3.172*	*0.111*	*0.244*	*5.2E-06*	*1.1E-05*	*7.2E-04*	*1.9E-06*	*1.1E-05*	*6.7E-07*	*2.0E-05*		21
24	*Existing AMUs:*		*0.306*	*0.671*	*0.306*	*0.671*	*0.024*	*0.053*	*2.521*	*5.521*	*8.211*	*17.983*	*0.234*	*0.512*	*1.1E-05*	*2.4E-05*	*1.5E-03*	*4.0E-06*	*2.2E-05*	*1.4E-06*	*4.2E-05*		22
25	*All AMUs:*		*0.452*	*0.990*	*0.452*	*0.990*	*0.036*	*0.078*	*3.711*	*8.126*	*9.660*	*21.155*	*0.345*	*0.756*	*1.6E-05*	*3.5E-05*	*2.2E-03*	*5.9E-06*	*3.3E-05*	*2.1E-06*	*6.2E-05*		23
26	*Building Totals:*																						24
27	*New Boilerhouse*		*0.037*	*0.082*	*0.037*	*0.082*	*0.003*	*0.006*	*0.304*	*0.665*	*0.370*	*0.810*	*0.028*	*0.062*	*1.3E-06*	*2.9E-06*	*1.8E-04*	*4.9E-07*	*2.7E-06*	*1.7E-07*	*5.1E-06*		25
28	*Old Boilerhouse*		*0.022*	*0.049*	*0.022*	*0.049*	*0.002*	*0.004*	*0.150*	*0.329*	*0.780*	*1.708*	*0.017*	*0.037*	*8.0E-07*	*1.7E-06*	*1.1E-04*	*2.9E-07*	*1.6E-06*	*1.0E-07*	*3.1E-06*		26
29	*Flake*		*0.094*	*0.205*	*0.094*	*0.205*	*0.007*	*0.016*	*0.764*	*1.674*	*0.930*	*2.038*	*0.072*	*0.157*	*3.3E-06*	*7.3E-06*	*4.6E-04*	*1.2E-06*	*6.8E-06*	*4.3E-07*	*1.3E-05*		27
30	*Receiving*		*0.024*	*0.052*	*0.024*	*0.052*	*0.002*	*0.004*	*0.182*	*0.398*	*0.460*	*1.007*	*0.018*	*0.040*	*8.5E-07*	*1.9E-06*	*1.2E-04*	*3.1E-07*	*1.7E-06*	*1.1E-07*	*3.3E-06*		28
31	*Main*		*0.275*	*0.602*	*0.275*	*0.602*	*0.022*	*0.048*	*2.311*	*5.061*	*7.119*	*15.592*	*0.210*	*0.460*	*9.8E-06*	*2.1E-05*	*1.4E-03*	*3.6E-06*	*2.0E-05*	*1.3E-06*	*3.8E-05*		29
32																							30
33	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*		31
34	Notes:																						32

	A	B	C	D	E
1					
2			**Stack**	**Stack Exhaust, cfm**	
3	**Stack**	**Building Air Source**	**Temp, °F**	**actual**	**68 ° F**
4	Boiler 1A	New Boilerhouse	306	34,480	23,762
5	Boiler 2A	New Boilerhouse	306	34,480	23,762
6	Kipper Boiler	NA - Ambient	129	26,238	23,519
7	Boiler 2	NA - Ambient	450	20,446	11,860
8	Flake North	Flake	115	68,000	62,438
9	Flake South	Flake	115	68,000	62,438
10	P4A	Main	145	18,710	16,328
11	P4BCD	Main	145	18,713	16,330
12	7020	Main	97	7,288	6,909
13	7101	Main	174	27,572	22,960
14	7102	Main	153	26,443	22,774
15	7019	Main	135	18,743	16,631
16	7001	Main	90	2,919	2,802
17	7027	Main	85	2,281	2,210
18	7006	Main	90	1,891	1,815
19	5037	Main	130	10,157	9,089
20	5034	Main	150	1,087	941
21	4000	Main	147	27,666	24,063
22	228	Main	133	15,890	14,147
23	234	Main	157	24,532	20,991
24	M33	Main	160	7,000	5,961
25	M44	Main	293	1,844	1,293
26	M56	Main	170	2,500	2,095
27	M62	Main	140	3,000	2,640
28	M86	Main	137	6,500	5,748
29	707	Main	90	1,118	1,073
30	725	Main	90	796	764
31	8	Main	81	2,059	2,009
32	5001	Main	76	605	596
33	5000	Main	80	618	604
34	432	Main	80	466	455
35	322	Main	180	426	351
36	572	Main	90	691	664
37					
38	*Retired Stacks*				
39	Boiler1		500	19,972	10,982
40	613/614		140	11,041	9,715
41	615/616		192	9,929	8,040
42	638		162	2,599	2,206

	A	B	C	D	E	F
1						
2			Building Exhaust Summary			
3		Makeup Air,	cfm*		% of makeup supply	
4	Building	cfm	Stacks	Fugitive	Stacks	Fugitive
5	Main	340,000	202,244	137,756	59.5%	40.5%
6	Old Boilerhouse	30,000	0	30,000	0.0%	100.0%
7	New Boilerhouse	70,000	47,524	22,476	67.9%	32.1%
8	Flake	176,000	124,877	51,123	71.0%	29.0%
9	Receiving	40,000	0	40,000	0.0%	100.0%
10						
11						
12						
13	* Corrected to 68 °F					

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1																				
2			Emissions Rates by Building																	
3			New Boilerhouse			Old Boilerhouse			Flake			Receiving			Main					
4	Pollutant		Total	Process Exhausts	Fugitive	Total	Process Exhausts	Fugitive	Total	Process Exhausts	Fugitive	Total	Process Exhausts	Fugitive	Total	Process Exhausts	Fugitive			
5	PM10	Hourly, lb/hr	0.037	0.025	0.012	0.022	0.000	0.022	0.094	0.067	0.027	0.024	0.000	0.024	0.275	0.164	0.111			
6		Annual, ton/yr	0.082	0.055	0.026	0.049	0.000	0.049	0.205	0.146	0.060	0.052	0.000	0.052	0.602	0.358	0.244			
7	PM2.5	Hourly, lb/hr	0.037	0.025	0.012	0.022	0.000	0.022	0.094	0.067	0.027	0.024	0.000	0.024	0.275	0.164	0.111			
8		Annual, ton/yr	0.082	0.055	0.026	0.049	0.000	0.049	0.205	0.146	0.060	0.052	0.000	0.052	0.602	0.358	0.244			
9	SO2	Hourly, lb/hr	0.003	0.002	0.001	0.002	0.000	0.002	0.007	0.005	0.002	0.002	0.000	0.002	0.022	0.013	0.009			
10		Annual, ton/yr	0.006	0.004	0.002	0.004	0.000	0.004	0.016	0.012	0.005	0.004	0.000	0.004	0.048	0.028	0.019			
11	NOx	Hourly, lb/hr	0.304	0.206	0.098	0.150	0.000	0.150	0.764	0.542	0.222	0.182	0.000	0.182	2.311	1.375	0.936			
12		Annual, ton/yr	0.665	0.452	0.214	0.329	0.000	0.329	1.674	1.188	0.486	0.398	0.000	0.398	5.061	3.010	2.051			
13	CO	Hourly, lb/hr	0.370	0.251	0.119	0.780	0.000	0.780	0.930	0.660	0.270	0.460	0.000	0.460	7.119	4.235	2.885			
14		Annual, ton/yr	0.810	0.550	0.260	1.708	0.000	1.708	2.038	1.446	0.592	1.007	0.000	1.007	15.592	9.274	6.317			
15	VOC	Hourly, lb/hr	0.028	0.019	0.009	0.017	0.000	0.017	0.072	0.051	0.021	0.018	0.000	0.018	0.210	0.125	0.085			
16		Annual, ton/yr	0.062	0.042	0.020	0.037	0.000	0.037	0.157	0.111	0.046	0.040	0.000	0.040	0.460	0.273	0.186			
17	Pb	Hourly, lb/hr	1.3E-06	9.0E-07	4.3E-07	8.0E-07	0.0E+00	8.0E-07	3.3E-06	2.4E-06	9.7E-07	8.5E-07	0.0E+00	8.5E-07	9.8E-06	5.8E-06	4.0E-06			
18		Annual, ton/yr	2.9E-06	2.0E-06	9.3E-07	1.7E-06	0.0E+00	1.7E-06	7.3E-06	5.2E-06	2.1E-06	1.9E-06	0.0E+00	1.9E-06	2.1E-05	1.3E-05	8.7E-06			
19	HCOH	lb/yr	1.8E-04	1.2E-04	5.9E-05	1.1E-04	0.0E+00	1.1E-04	4.6E-04	3.3E-04	1.3E-04	1.2E-04	0.0E+00	1.2E-04	1.36E-03	8.1E-04	5.5E-04		59.48%	40.52%
20	As	lb/yr	4.9E-07	3.3E-07	1.6E-07	2.9E-07	0.0E+00	2.9E-07	1.2E-06	8.8E-07	3.6E-07	3.1E-07	0.0E+00	3.1E-07	3.6E-06	2.2E-06	1.5E-06		59.48%	40.52%
21	Cd	lb/yr	2.7E-06	1.8E-06	8.7E-07	1.6E-06	0.0E+00	1.6E-06	6.8E-06	4.8E-06	2.0E-06	1.7E-06	0.0E+00	1.7E-06	2.0E-05	1.2E-05	8.1E-06		59.48%	40.52%
22	Cr(VI)	lb/yr	1.7E-07	1.2E-07	5.5E-08	1.0E-07	0.0E+00	1.0E-07	4.3E-07	3.1E-07	1.3E-07	1.1E-07	0.0E+00	1.1E-07	1.3E-06	7.5E-07	5.1E-07		59.48%	40.52%
23	Ni	lb/yr	5.1E-06	3.5E-06	1.7E-06	3.1E-06	0.0E+00	3.1E-06	1.3E-05	9.2E-06	3.8E-06	3.3E-06	0.0E+00	3.3E-06	3.8E-05	2.3E-05	1.5E-05		59.48%	40.52%

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
1																					
2																					
3																					
4			PM10		PM2.5		NOx		CO		SO2		VOC		Pb		HCOH	As	Cd	Cr(VI)	Ni
5	Building	Fugitive Source ID	Hourly, lb/hr	Annual, ton/yr	Hourly, lb/hr	Annual, ton/yr	Hourly, lb/hr	Annual, ton/yr	Hourly, lb/hr	Annual, ton/yr	Hourly, lb/hr	Annual, ton/yr	Hourly, lb/hr	Annual, ton/yr	Hourly, lb/hr	Annual, ton/yr	lb/yr	lb/yr	lb/yr	lb/yr	lb/yr
6	Main	MAIN_XSTG	0.111	0.244	0.111	0.244	0.936	2.051	2.885	6.317	0.009	0.019	0.085	0.186	4.0E-06	8.7E-06	5.5E-04	1.5E-06	8.1E-06	5.1E-07	1.5E-05
7	Old Boilerhouse	OLD_BLRS	0.022	0.049	0.022	0.049	0.150	0.329	0.780	1.708	0.002	0.004	0.017	0.037	8.0E-07	1.7E-06	1.1E-04	2.9E-07	1.6E-06	1.0E-07	3.1E-06
8	New Boilerhouse	NEW_BLRS	0.012	0.026	0.012	0.026	0.098	0.214	0.119	0.260	0.001	0.002	0.009	0.020	4.3E-07	9.3E-07	5.9E-05	1.6E-07	8.7E-07	5.5E-08	1.7E-06
9	Flake	FLAKE	0.027	0.060	0.027	0.060	0.222	0.486	0.270	0.592	0.002	0.005	0.021	0.046	9.7E-07	2.1E-06	1.3E-04	3.6E-07	2.0E-06	1.3E-07	3.8E-06
10	Receiving	RCVG	0.024	0.052	0.024	0.052	0.182	0.398	0.460	1.007	0.002	0.004	0.018	0.040	8.5E-07	1.9E-06	1.2E-04	3.1E-07	1.7E-06	1.1E-07	3.3E-06

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X
1						AMU Emissions Allocated to Stacks																		
2				Stack	% of Building	PM10		PM2.5		NOx		CO		SO2		VOC		Pb		TAP Emissions, lb/yr				
3	Emission Point	Associated Building	Process Air Source	Exhaust @ 68 ° F	AMU Emission	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	Hourly, lb/hr	Annual, ton/yr	Hourly, lb/hr	Annual, ton/yr	Hourly, lb/hr	Annual, ton/yr	Hourly, lb/hr	Annual, ton/yr	HCOH	As	Cd	Cr(VI)	Ni
4	Boiler 1A	New Boilerhouse	Room	23,762	33.9%	0.013	0.028	0.013	0.028	0.103	0.226	0.126	0.275	0.001	0.002	0.010	0.021	4.5E-07	9.9E-07	6.2E-05	1.7E-07	9.2E-07	5.8E-08	1.7E-06
5	Boiler 2A	New Boilerhouse	Room	23,762	33.9%	0.013	0.028	0.013	0.028	0.103	0.226	0.126	0.275	0.001	0.002	0.010	0.021	4.5E-07	9.9E-07	6.2E-05	1.7E-07	9.2E-07	5.8E-08	1.7E-06
6	Kipper Boiler	Old Boilerhouse	Outside	23,519	0.0%	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
7	Boiler 2	Old Boilerhouse	Outside	11,860	0.0%	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
8	Flake North	Flake	Room	62,438	35.5%	0.033	0.073	0.033	0.073	0.271	0.594	0.330	0.723	0.003	0.006	0.025	0.056	1.2E-06	2.6E-06	1.6E-04	4.4E-07	2.4E-06	1.5E-07	4.6E-06
9	Flake South	Flake	Room	62,438	35.5%	0.033	0.073	0.033	0.073	0.271	0.594	0.330	0.723	0.003	0.006	0.025	0.056	1.2E-06	2.6E-06	1.6E-04	4.4E-07	2.4E-06	1.5E-07	4.6E-06
10	P4A	Main	Room	16,328	4.8%	0.013	0.029	0.013	0.029	0.111	0.243	0.342	0.749	0.001	0.002	0.010	0.022	4.7E-07	1.0E-06	6.5E-05	1.7E-07	9.6E-07	6.1E-08	1.8E-06
11	P4BCD	Main	Room	16,330	4.8%	0.013	0.029	0.013	0.029	0.111	0.243	0.342	0.749	0.001	0.002	0.010	0.022	4.7E-07	1.0E-06	6.5E-05	1.7E-07	9.6E-07	6.1E-08	1.8E-06
12	7020	Main	Room	6,909	2.0%	0.006	0.012	0.006	0.012	0.047	0.103	0.145	0.317	0.000	0.001	0.004	0.009	2.0E-07	4.4E-07	2.8E-05	7.4E-08	4.0E-07	2.6E-08	7.7E-07
13	7101	Main	Room	22,960	6.8%	0.019	0.041	0.019	0.041	0.156	0.342	0.481	1.053	0.001	0.003	0.014	0.031	6.6E-07	1.4E-06	9.2E-05	2.4E-07	1.3E-06	8.6E-08	2.6E-06
14	7102	Main	Room	22,774	6.7%	0.018	0.040	0.018	0.040	0.155	0.339	0.477	1.044	0.001	0.003	0.014	0.031	6.6E-07	1.4E-06	9.1E-05	2.4E-07	1.3E-06	8.5E-08	2.5E-06
15	7019	Main	Room	16,631	4.9%	0.013	0.029	0.013	0.029	0.113	0.248	0.348	0.763	0.001	0.002	0.010	0.022	4.8E-07	1.1E-06	6.6E-05	1.8E-07	9.7E-07	6.2E-08	1.9E-06
16	7001	Main	Room	2,802	0.8%	0.002	0.005	0.002	0.005	0.019	0.042	0.059	0.129	0.000	0.000	0.002	0.004	8.1E-08	1.8E-07	1.1E-05	3.0E-08	1.6E-07	1.0E-08	3.1E-07
17	7027	Main	Room	2,210	0.6%	0.002	0.004	0.002	0.004	0.015	0.033	0.046	0.101	0.000	0.000	0.001	0.003	6.4E-08	1.4E-07	8.8E-06	2.4E-08	1.3E-07	8.2E-09	2.5E-07
18	7006	Main	Room	1,815	0.5%	0.001	0.003	0.001	0.003	0.012	0.027	0.038	0.083	0.000	0.000	0.001	0.002	5.2E-08	1.1E-07	7.2E-06	1.9E-08	1.1E-07	6.8E-09	2.0E-07
19	5037	Main	Room	9,089	2.7%	0.007	0.016	0.007	0.016	0.062	0.135	0.190	0.417	0.001	0.001	0.006	0.012	2.6E-07	5.7E-07	3.6E-05	9.7E-08	5.3E-07	3.4E-08	1.0E-06
20	5034	Main	Room	941	0.3%	0.001	0.002	0.001	0.002	0.006	0.014	0.020	0.043	0.000	0.000	0.001	0.001	2.7E-08	5.9E-08	3.8E-06	1.0E-08	5.5E-08	3.5E-09	1.1E-07
21	4000	Main	Room	24,063	7.1%	0.019	0.043	0.019	0.043	0.164	0.358	0.504	1.103	0.002	0.003	0.015	0.033	6.9E-07	1.5E-06	9.6E-05	2.6E-07	1.4E-06	9.0E-08	2.7E-06
22	228	Main	Room	14,147	4.2%	0.011	0.025	0.011	0.025	0.096	0.211	0.296	0.649	0.001	0.002	0.009	0.019	4.1E-07	8.9E-07	5.6E-05	1.5E-07	8.3E-07	5.3E-08	1.6E-06
23	234	Main	Room	20,991	6.2%	0.017	0.037	0.017	0.037	0.143	0.312	0.440	0.963	0.001	0.003	0.013	0.028	6.1E-07	1.3E-06	8.4E-05	2.2E-07	1.2E-06	7.8E-08	2.3E-06
24	M33	Main	Room	5,961	1.8%	0.005	0.011	0.005	0.011	0.041	0.089	0.125	0.273	0.000	0.001	0.004	0.008	1.7E-07	3.8E-07	2.4E-05	6.3E-08	3.5E-07	2.2E-08	6.7E-07
25	M44	Main	Room	1,293	0.4%	0.001	0.002	0.001	0.002	0.009	0.019	0.027	0.059	0.000	0.000	0.001	0.002	3.7E-08	8.2E-08	5.2E-06	1.4E-08	7.6E-08	4.8E-09	1.4E-07
26	M56	Main	Room	2,095	0.6%	0.002	0.004	0.002	0.004	0.014	0.031	0.044	0.096	0.000	0.000	0.001	0.003	6.0E-08	1.3E-07	8.4E-06	2.2E-08	1.2E-07	7.8E-09	2.3E-07
27	M62	Main	Room	2,640	0.8%	0.002	0.005	0.002	0.005	0.018	0.039	0.055	0.121	0.000	0.000	0.002	0.004	7.6E-08	1.7E-07	1.1E-05	2.8E-08	1.5E-07	9.8E-09	2.9E-07
28	M86	Main	Room	5,748	1.7%	0.005	0.010	0.005	0.010	0.039	0.086	0.120	0.264	0.000	0.001	0.004	0.008	1.7E-07	3.6E-07	2.3E-05	6.1E-08	3.4E-07	2.1E-08	6.4E-07
29	707	Main	Room	1,073	0.3%	0.001	0.002	0.001	0.002	0.007	0.016	0.022	0.049	0.000	0.000	0.001	0.001	3.1E-08	6.8E-08	4.3E-06	1.1E-08	6.3E-08	4.0E-09	1.2E-07
30	725	Main	Room	764	0.2%	0.001	0.001	0.001	0.001	0.005	0.011	0.016	0.035	0.000	0.000	0.000	0.001	2.2E-08	4.8E-08	3.0E-06	8.1E-09	4.5E-08	2.8E-09	8.5E-08
31	8	Main	Room	2,009	0.6%	0.002	0.004	0.002	0.004	0.014	0.030	0.042	0.092	0.000	0.000	0.001	0.003	5.8E-08	1.3E-07	8.0E-06	2.1E-08	1.2E-07	7.5E-09	2.2E-07
32	5001	Main	Room	596	0.2%	0.000	0.001	0.000	0.001	0.004	0.009	0.012	0.027	0.000	0.000	0.000	0.001	1.7E-08	3.8E-08	2.4E-06	6.3E-09	3.5E-08	2.2E-09	6.7E-08
33	5000	Main	Room	604	0.2%	0.000	0.001	0.000	0.001	0.004	0.009	0.013	0.028	0.000	0.000	0.000	0.001	1.7E-08	3.8E-08	2.4E-06	6.4E-09	3.5E-08	2.3E-09	6.8E-08
34	432	Main	Room	455	0.1%	0.000	0.001	0.000	0.001	0.003	0.007	0.010	0.021	0.000	0.000	0.000	0.001	1.3E-08	2.9E-08	1.8E-06	4.8E-09	2.7E-08	1.7E-09	5.1E-08
35	322	Main	Room	351	0.1%	0.000	0.001	0.000	0.001	0.002	0.005	0.007	0.016	0.000	0.000	0.000	0.000	1.0E-08	2.2E-08	1.4E-06	3.7E-09	2.1E-08	1.3E-09	3.9E-08
36	572	Main	Room	664	0.2%	0.001	0.001	0.001	0.001	0.005	0.010	0.014	0.030	0.000	0.000	0.000	0.001	1.9E-08	4.2E-08	2.6E-06	7.1E-09	3.9E-08	2.5E-09	7.4E-08
37			*sum for Main*	*202,244*	*59.5%*	*0.164*	*0.358*	*0.164*	*0.358*	*1.375*	*3.010*	*4.235*	*9.274*	*0.013*	*0.028*	*0.125*	*0.273*	*5.8E-06*	*1.3E-05*	*8.1E-04*	*2.2E-06*	*1.2E-05*	*7.5E-07*	*2.3E-05*
38	*Retired Stacks*																							
39	Boiler1	0	Outside	10,982																				
40	613/614	0	Room	9,715																				
41	615/616	0	Room	8,040																				
42	638	0	Room	2,206																				

MEMORANDUM DRAFT

DATE: **August** 27, 2019

TO: Shawnee Chen, Permit Writer, Air Program

FROM: Thomas Swain, Modeling Review Analyst, Air Program

PROJECT: 2011.0132 PROJ 62264, Rexburg Facility of Basic American Foods, Installation of New Dehydration Line and Air Makeup Units, Replacement of Boiler and One Belt Dryer, and increasing Production, located in Rexburg, Idaho.

SUBJECT: Demonstration of Compliance with IDAPA 58.01.01.203.02 (NAAQS) and 203.03 (TAPs) as it relates to air quality impact analyses.

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Acronyms, Units, and Chemical Nomenclature

REXBAF	Rexburg Facility of Basic American Foods
CCE	Coal Creek Environmental
AAC	Acceptable Ambient Concentration of a non-carcinogenic TAP
AACC	Acceptable Ambient Concentration of a Carcinogenic TAP
acfm	Actual cubic feet per minute
AERMAP	The terrain data preprocessor for AERMOD
AERMET	The meteorological data preprocessor for AERMOD
AERMOD	American Meteorological Society/Environmental Protection Agency Regulatory Model
Appendix W	40 CFR 51, Appendix W – Guideline on Air Quality Models
AS	Arsenic
ASOS	Automated Surface Observing System
BPIP	Building Profile Input Program
BRC	Below Regulatory Concern
CCE	Coal Creek Environmental
CD	Cadmium
CFR	Code of Federal Regulations
CMAQ	Community Multi-Scale Air Quality Modeling System
CO	Carbon Monoxide
CR	Chromium (VI)
DEM	Digital Elevation Map
DEQ	Idaho Department of Environmental Quality
DV	Design Values
EL	Emissions Screening Level of a TAP
EPA	United States Environmental Protection Agency
FORM	Formaldehyde
GEP	Good Engineering Practice
hr	hours
Idaho Air Rules	Rules for the Control of Air Pollution in Idaho, located in the Idaho Administrative Procedures Act 58.01.01
ISCST3	Industrial Source Complex Short Term 3 dispersion model
K	Kelvin
lb/hr	Pounds per hour
m	Meters
m/sec	Meters per second
MMBtu	Million British Thermal Units
NAAQS	National Ambient Air Quality Standards
NAD83	North American Datum of 1983
NED	National Elevation Dataset
NI	Nickel
NO	Nitrogen Oxide
NO_2	Nitrogen Dioxide
NOx	Oxides of Nitrogen
NWS	National Weather Service

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O_3	Ozone
OLM	Ozone Limiting Method
Pb	Lead
PM_{10}	Particulate matter with an aerodynamic particle diameter less than or equal to a nominal 10 micrometers
$PM_{2.5}$	Particulate matter with an aerodynamic particle diameter less than or equal to a nominal 2.5 micrometers
ppb	parts per billion
PRIME	Plume Rise Model Enhancement
PSD	Prevention of Significant Deterioration
PTC	Permit to Construct
PTE	Potential to Emit
PVMRM	Plume Volume Molar Ratio Method
REXBAF	Rexburg Facility of Basic American Foods
SIL	Significant Impact Level
SO_2	Sulfur Dioxide
TAP	Toxic Air Pollutant
tpy	Tons per year
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compounds
^oF	Degrees Fahrenheit
$\mu g/m^3$	Micrograms per cubic meter of air

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1.0 Summary

Rexburg Facility of Basic American Foods, (REXBAF) submitted a Permit to Construct (PTC) application for modifications to their existing facility located in Rexburg, Idaho. Project-specific air quality analyses involving atmospheric dispersion modeling of estimated emissions associated with the proposed modification were submitted to DEQ to demonstrate that applicable emissions do not result in violation of a National Ambient Air Quality Standard (NAAQS) or Toxic Air Pollutant (TAP) increment as required by the Idaho Administrative Procedures Act 58.01.01.203.02 and 203.03 (Idaho Air Rules Section 203.02 and 203.03). This memorandum provides a summary of the applicability assessment for analyses and air impact analyses used to demonstrate compliance with applicable NAAQS and TAP increments, as required by Idaho Air Rules Section 203.02 and 203.03.

Stephen Nelson of Coal Creek Environmental (CCE), on behalf of REXBAF, prepared the PTC application and performed ambient air impact analyses for this project. DEQ review of submitted data and DEQ analyses summarized by this memorandum addressed only the rules, policies, methods, and data pertaining to the air impact analyses used to demonstrate that estimated emissions associated with operation of the facility will not cause or significantly contribute to a violation of any applicable air quality standard. This review did not address/evaluate compliance with other rules or analyses not pertaining to the air impact analyses. Evaluation of emission estimates was the responsibility of the DEQ permit writer and is addressed in the main body of the DEQ Statement of Basis, and emission calculation methods were not evaluated in this modeling review memorandum.

Table 1 presents key assumptions and results to be considered in the development of the permit. Idaho Air Rules require air impact analyses be conducted in accordance with methods outlined in 40 CFR 51, Appendix W *Guideline on Air Quality Models* (Appendix W). Appendix W requires that air quality impacts be assessed using atmospheric dispersion models with emissions and operations representative of design capacity or as limited by a federally enforceable permit condition.

The submitted information and analyses: 1) utilized appropriate methods and models; 2) was conducted using reasonably accurate or conservative model parameters and input data (review of emission estimates was addressed by the DEQ permit writer); 3) adhered to established DEQ guidelines for new source review dispersion modeling; 4) showed either a) that estimated potential/allowable emissions are at a level defined as below regulatory concern (BRC) and do not require a NAAQS compliance demonstration; b) that predicted pollutant concentrations from emissions associated with the project as modeled were below Significant Impact Levels (SILs) or other applicable regulatory thresholds; or c) that predicted pollutant concentrations from emissions associated with the project, when appropriately combined with co-contributing sources and background concentrations, were below applicable NAAQS at ambient air locations where and when the project has a significant impact; 5) showed that TAP emission increases associated with the project will not result in increased ambient air impacts exceeding allowable TAP increments. This conclusion assumes that conditions in Table 1 are representative of facility design capacity or operations as limited by a federally enforceable permit condition. The DEQ permit writer should use Table 1 and other information presented in this memorandum to generate appropriate permit provisions/restrictions to assure emissions do not exceed applicable regulatory thresholds requiring further analyses and to assure the requirements of Appendix W are met regarding emissions representative of design capacity or permit allowable rates.

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Summary of Submittals and Actions

- 07/11/2019: PTC application
  Public comment period requested
- 08/08/2019: Completeness date

Table 1. KEY ASSUMPTIONS USED IN MODELING ANALYSES	
Criteria/Assumption/Result	**Explanation/Consideration**
General Emission Rates. Emission rates used in the air impact analyses, as listed in this memorandum, must represent maximum potential emissions as given by design capacity, inherently limited by the nature of the process or configuration of the facility, or as limited by the issued permit for the specific pollutant and averaging period.	Compliance has not been demonstrated for emission rates greater than those used in the air impact analyses.
Air Impact Analyses for Criteria Pollutant Emissions. The facility is not qualified for a BRC exemption because of proposed increases in permit throughputs. The proposed PTE emissions for the modification are greater than DEQ Level 1 modeling thresholds for annual and 24-hour $PM_{2.5}$[a], 24-hour PM_{10}[b], CO, 1-hour and annual NO_2. Therefore, these pollutants and averaging times are subject to NAAQS Compliance Demonstration requirements.[c]	Project-specific air impact analyses demonstrating compliance with NAAQS, as required by Idaho Air Rules Section 203.02, are required for pollutant increases above BRC thresholds, or for pollutants having an emissions increase that is greater than Level I modeling applicability thresholds (where the BRC exclusion cannot be used).
Air Impact Analyses for TAP Emissions. Allowable emissions of TAPS other than Formaldehyde (FORM), Arsenic (AS), Cadmium (CD), Hexavalent Chromium (CR6+), and Nickel (NI) are either below ELS or not applicable due to NESHAP regulations. Analyses demonstrating compliance with these five TAPS were performed.	A TAP increment compliance demonstration would be required for any TAPs with emissions above ELs.
Revised Building Construction. BPIP PRIME has been utilized for both existing conditions and proposed conditions.	Compliance has been demonstrated for conditions that take into consideration the differences in building wake effects of the new building construction.
Modeling Scenarios. The Kipper Boiler and the existing Boiler 2 are operating exclusively of each other	Compliance has not been demonstrated for operating scenarios when the Kipper Boiler and the existing Boiler 2 are operating at the same time.

a. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
b. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
c. CCE selected to use Level II modeling thresholds for its analyses. DEQ is using Level I modeling thresholds,

2.0 Background Information

This section provides background information applicable to the project and the site proposed for the facility. It also provides a brief description of the applicable air impact analyses requirements for the project.

2.1 Project Description

The REXBAF project is for a modification to a potato processing facility located in Rexburg, Idaho. The project includes the following items:

- installation of two new natural gas, low NOx (15 ppmv NOx) boilers
- installation of a potato flake production line with steam-heated drum dryers utilizing wet scrubbing to control particulate emissions

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- an existing belt dryer (associated with the existing stacks denoted 613/614, 615/616, and 638) will be replaced with a belt dryer being relocated from the BAF facility in Blackfoot, Idaho.
- Increase in maximum daily production rates from the Process A production line
- Removal of burning coal in the Kipper Boiler; limiting annual usage of the Kipper Boiler as a backup or standby unit
- Removal of Boiler 1; the existing Boiler 2 will be used largely in backup or standby operations and only when the Kipper Boiler is not operating; two modeling scenarios are required
- Installation of seven new NG direct fired air make-up units.
- extensions to the existing building structure to house the new drum dryers and boilers
- relocation of the wood fuel pile (for the Kipper Boiler)

The PTC addresses all air pollutant-emitting activities associated with the facility.

2.2 Proposed Location and Area Classification

The facility is located in Rexburg, within Madison county (Northing: 4854,300 m; Easting: 437050 m; UTM Zone 12). This area is designated as an attainment or unclassifiable area for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), lead (Pb), ozone (O_3), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}), and particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers ($PM_{2.5}$). The area is not classified as non-attainment for any criteria pollutants.

2.3 Air Impact Analyses Required for All Permits to Construct

Idaho Air Rules Sections 203.02 and 203.03:

> *No permit to construct shall be granted for a new or modified stationary source unless the applicant shows to the satisfaction of the Department all of the following:*
>
> ***02. NAAQS**. The stationary source or modification would not cause or significantly contribute to a violation of any ambient air quality standard.*
>
> ***03. Toxic Air Pollutants.** Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regards to the pollutants listed in Sections 585 and 586.*

Atmospheric dispersion modeling, using computerized simulations, is used to demonstrate compliance with both NAAQS and TAPs. Idaho Air Rules Section 202.02 states:

> ***02. Estimates of Ambient Concentrations**. All estimates of ambient concentrations shall be based on the applicable air quality models, data bases, and other requirements specified in 40 CFR 51 Appendix W (Guideline on Air Quality Models).*

2.4 Significant Impact Level and Cumulative NAAQS Impact Analyses

If specific criteria pollutant emission increases associated with the proposed permitting project cannot

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qualify for a BRC exemption as per Idaho Air Rules Section 221, then the permit cannot be issued unless the application demonstrates that applicable emission increases will not cause or significantly contribute to a violation of NAAQS, as required by Idaho Air Rules Section 203.02.

The first phase of a NAAQS compliance demonstration is to evaluate whether the proposed facility/project could have a significant impact to ambient air. Section 3.1.1 of this memorandum describes the applicability evaluation of Idaho Air Rules Section 203.02. The Significant Impact Level (SIL) analysis for a new facility or proposed modification to a facility involves modeling estimated criteria air pollutant emissions from the facility or modification to determine the potential impacts to ambient air. Air impact analyses are required by Idaho Air Rules to be conducted in accordance with methods outlined in Appendix W. Appendix W requires that facilities be modeled using emissions and operations representative of design capacity or as limited by a federally enforceable permit condition.

A facility or modification is considered to have a significant impact on air quality if maximum modeled impacts to ambient air exceed the established SIL listed in Idaho Air Rules Section 006 (referred to as a "significant contribution" in Idaho Air Rules) or as incorporated by reference as per Idaho Air Rules Section 107.03.b. Table 2 lists the applicable SILs.

Table 2. APPLICABLE REGULATORY LIMITS

Pollutant	Averaging Period	Significant Impact Levels[a] ($\mu g/m^3$)[b]	Regulatory Limit[c] ($\mu g/m^3$)	Modeled Design Value Used[d]
PM_{10}[e]	24-hour	5.0	150[f]	Maximum 6th highest[g]
$PM_{2.5}$[h]	24-hour	1.2	35[i]	Mean of maximum 8th highest[j]
	Annual	0.2	12[k]	Mean of maximum 1st highest[j]
Carbon monoxide (CO)	1-hour	2,000	40,000[m]	Maximum 2nd highest[n]
	8-hour	500	10,000[m]	Maximum 2nd highest[n]
Sulfur Dioxide (SO_2)	1-hour	3 ppb[o] (7.8 $\mu g/m^3$)	75 ppb[p] (196 $\mu g/m^3$)	Mean of maximum 4th highest[q]
	3-hour	25	1,300[m]	Maximum 2nd highest[n]
	24-hour	5	365[m]	Maximum 2nd highest[n]
	Annual	1.0	80[r]	Maximum 1st highest[n]
Nitrogen Dioxide (NO_2)	1-hour	4 ppb (7.5 $\mu g/m^3$)	100 ppb[s] (188 $\mu g/m^3$)	Mean of maximum 8th highest[t]
	Annual	1.0	100[r]	Maximum 1st highest[n]
Lead (Pb)	3-month[u]	NA	0.15[r]	Maximum 1st highest[n]
	Quarterly	NA	1.5[r]	Maximum 1st highest[n]
Ozone (O_3)	8-hour	40 TPY VOC[v]	70 ppb[w]	Not typically modeled

a. Idaho Air Rules Section 006 (definition for significant contribution) or as incorporated by reference as per Idaho Air Rules Section 107.03.b.
b. Micrograms per cubic meter.
c. Incorporated into Idaho Air Rules by reference, as per Idaho Air Rules Section 107.
d. The maximum 1st highest modeled value is always used for the significant impact analysis unless indicated otherwise. Modeled design values are calculated for each ambient air receptor.
e. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
f. Not to be exceeded more than once per year on average over 3 years.
g. Concentration at any modeled receptor when using five years of meteorological data.
h. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
i. 3-year mean of the upper 98th percentile of the annual distribution of 24-hour concentrations.
j. 5-year mean of the 8th highest modeled 24-hour concentrations at the modeled receptor for each year of meteorological data modeled. For the SIL analysis, the 5-year mean of the 1st highest modeled 24-hour impacts at the modeled receptor for each year.
k. 3-year mean of annual concentration.
l. 5-year mean of annual averages at the modeled receptor.
m. Not to be exceeded more than once per year.
n. Concentration at any modeled receptor.
o. Interim SIL established by EPA policy memorandum.
p. 3-year mean of the upper 99th percentile of the annual distribution of maximum daily 1-hour concentrations.
q. 5-year mean of the 4th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of 1st highest modeled 1-hour impacts for each year is used.
r. Not to be exceeded in any calendar year.
s. 3-year mean of the upper 98th percentile of the annual distribution of maximum daily 1-hour concentrations.
t. 5-year mean of the 8th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of maximum modeled 1-hour impacts for each year is used.
u. 3-month rolling average.
v. An annual emissions rate of 40 ton/year of VOCs is considered significant for O_3.
w. Annual 4th highest daily maximum 8-hour concentration averaged over three years.

If modeled maximum pollutant impacts to ambient air from the emission sources associated with a new facility or modification exceed the SILs, then a cumulative NAAQS impact analysis is necessary to demonstrate compliance with NAAQS and Idaho Air Rules Section 203.02.

A cumulative NAAQS impact analysis for attainment area pollutants involves assessing ambient impacts (typically the design values consistent with the form of the standard) from potential/allowable emissions resulting from the project and emissions from any nearby co-contributing sources (including existing emissions from the facility that are unrelated to the project), and then adding a DEQ-approved background concentration value to the modeled result that is appropriate for the criteria pollutant/averaging-period at the facility location and the area of significant impact. The resulting pollutant concentrations in ambient air are then compared to the NAAQS listed in Table 2. Table 2 also lists SILs and specifies the modeled design value that must be used for comparison to the NAAQS. NAAQS compliance is evaluated on a receptor-by-receptor basis for the modeling domain.

If the cumulative NAAQS impact analysis indicates a violation of the standard, the permit may not be issued if the proposed project has a significant contribution (exceeding the SIL) to the modeled violation. If project-specific impacts are below the SIL, then the project does not have a significant contribution to the specific violations.

Compliance with Idaho Air Rules Section 203.02 is generally demonstrated if: a) applicable specific criteria pollutant emission increases are at a level defined as BRC, using the criteria established by DEQ regulatory interpretation[1]; or b) all modeled impacts of the SIL analysis are below the applicable SIL or other level determined to be inconsequential to NAAQS compliance; or c) modeled design values of the cumulative NAAQS impact analysis (modeling all emissions from the facility and co-contributing

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sources, and adding a background concentration) are less than applicable NAAQS at receptors where impacts from the proposed facility/modification exceeded the SIL or other identified level of consequence; or d) if the cumulative NAAQS analysis showed NAAQS violations, the impact of proposed facility/modification to any modeled violation was inconsequential (typically assumed to be less than the established SIL) for that specific receptor and for the specific modeled time when the violation occurred.

2.5 Toxic Air Pollutant Analyses

Emissions of toxic substances are generally addressed by Idaho Air Rules Section 161:

> *Any contaminant which is by its nature toxic to human or animal life or vegetation shall not be emitted in such quantities or concentrations as to alone, or in combination with other contaminants, injure or unreasonably affect human or animal life or vegetation.*

Permitting requirements for toxic air pollutants (TAPs) from new or modified sources are specifically addressed by Idaho Air Rules Section 203.03 and require the applicant to demonstrate to the satisfaction of DEQ the following:

> *Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regards to the pollutants listed in Sections 585 and 586.*

Per Section 210, if the total project-wide emission increase of any TAP associated with a new source or modification exceeds screening emission levels (ELs) of Idaho Air Rules Section 585 or 586, then the ambient impact of the emission increase must be estimated. If ambient impacts are less than applicable Acceptable Ambient Concentrations (AACs) for non-carcinogens of Idaho Air Rules Section 585 and Acceptable Ambient Concentrations for Carcinogens (AACCs) of Idaho Air Rules Section 586, then compliance with TAP requirements has been demonstrated.

Idaho Air Rules Section 210.20 states that if TAP emissions from a specific source are regulated by the Department or EPA under 40 CFR 60, 61, or 63, then a TAP impact analysis under Section 210 is not required for that TAP. The DEQ permit writer evaluates the applicability of specific TAPs to the Section 210.20 exclusion.

3.0 Analytical Methods and Data

This section describes the methods and data used in the analyses to demonstrate compliance with applicable air quality impact requirements. The DEQ Statement of Basis provides a discussion of the methods and data used to estimate criteria and TAP emission rates.

3.1 Emission Source Data

Emissions of criteria pollutants and TAPs resulting from operation of the proposed REXBAF modification were estimated by CCE for various applicable averaging periods. The calculation of potential emissions is the responsibility of the DEQ permit writer, and the representativeness and

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accuracy of emission estimates is not addressed in this modeling memorandum. DEQ air impact analysts are responsible for assuring that potential emission rates provided in the emission inventory are properly used in the model. The rates listed must represent the maximum allowable rate as averaged over the specified period.

Emission rates used in the impact modeling applicability analyses and any modeling analyses, as listed in this memorandum, should be reviewed by the DEQ permit writer and compared with those in the final emission inventory. All modeled criteria air pollutant and TAP emission rates must be equal to or greater than the facility's potential emissions calculated in the PTC emission inventory or proposed permit allowable emission rates.

3.1.1 Modeling Applicability and Modeled Criteria Pollutant Emission Rates

If project-specific emission increases for criteria pollutants would qualify for a BRC permit exemption as per Idaho Air Rules Section 221 if it were not for potential emissions of one or more pollutants exceeding the BRC threshold of 10 percent of emissions defined by Idaho Air Rules as significant, then a NAAQS compliance demonstration may not be required for those pollutants with emissions below BRC levels. DEQ's regulatory interpretation policy of exemption provisions of Idaho Air Rules is that: "A DEQ NAAQS compliance assertion will not be made by the DEQ modeling group for specific criteria pollutants having a project emissions increase below BRC levels, provided the proposed project would have qualified for a Category I Exemption for BRC emissions quantities except for the emissions of another criteria pollutant.[1]" The interpretation policy also states that the exemption criteria of uncontrolled potential to emit (PTE) not to exceed 100 ton/year (Idaho Air Rules Section 220.01.a.i) is not applicable when evaluating whether a NAAQS impact analyses is required. A permit will be issued limiting PTE below 100 ton/year, thereby negating the need to maintain calculated uncontrolled PTE under 100 ton/year. The BRC exemption cannot be used to exempt a project from a pollutant-specific NAAQS compliance demonstration in most cases where a PTC is required for the action regardless of emission quantities, such as the modification of an existing emission or throughput limit.

A NAAQS compliance demonstration must be performed for pollutant increases that would not qualify for the BRC exemption from the requirement to demonstrate compliance with NAAQS.

Site-specific air impact modeling analyses may not be necessary for some pollutants, even where such emissions do not qualify for the BRC exemption. DEQ has developed modeling applicability thresholds, below which a site-specific modeling analysis is not required. DEQ generic air impact modeling analyses that were used to develop the modeling thresholds provide a conservative SIL analysis for projects with emissions below identified threshold levels. Project-specific modeling applicability thresholds are provided in the *Idaho Air Modeling Guideline*[2]. These thresholds were based on assuring an ambient impact of less than the established SIL for specific pollutants and averaging periods.

If total project-specific emission rate increases of a pollutant are below Level I Modeling Applicability Thresholds, then project-specific air impact analyses are not necessary for permitting. Use of Level II Modeling Applicability Thresholds are conditional, requiring DEQ approval. DEQ approval is based on dispersion-affecting characteristics of the emission sources such as stack height, stack gas exit velocity, stack gas temperature, distance from sources to ambient air, presence of elevated terrain, and potential exposure to sensitive public receptors.

NAAQS compliance demonstrations were required for this project since the submitted application demonstrated that the project -related emission increases were above Level I Modeling Applicability Thresholds. Project related emission increases do not qualify for a BRC exemption from NAAQS

compliance demonstration requirements because existing permit restrictions/provisions must be changed.

Table 3 provides a comparison between project allowable emissions and modeling applicability thresholds.

Table 3. SITE-SPECIFIC CRITERIA POLLUTANT MODELING APPLICABILITY

Pollutant	Averaging Period	Emissions	Level I Modeling Thresholds	Level II Modeling Thresholds[a]	Site-Specific Modeling Required?
PM_{10}[b]	24-hour	3.88 lb/hr	0.22	2.6	Yes
$PM_{2.5}$[c]	24-hour	3.86 lb/hr	0.054	0.63	Yes
	Annual	13.0 ton/yr	0.35	4.1	Yes
Carbon Monoxide (CO)	1-hour, 8-hour	35.5 lb/hr	15	175	Yes[d]
Sulfur Dioxide (SO_2)	1-hour, 3-hour, 24-hour	0.21 lb/hr	0.21	2.5	No
	Annual	0.8 ton/yr	1.2	14	No
Nitrogen Oxides (NOx)	1-hour	8.12 lb/hr	0.20	2.4	Yes
	Annual	26.4 ton/yr	1.2	14	Yes
Lead (Pb)	monthly	0.1 lb/month	14		No

a. Level II Modeling Thresholds were not approved by DEQ for this project.
b. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
c. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
d. Modeling was not performed by CCE for CO because emission increases were below Level II Thresholds . DEQ disagrees with this assessment and performed revised modeling analyses for CO impacts because CO emissions are significantly greater than Level I Modeling Thresholds. The impacts from the AMU sources are obviously significant, and the AMU sources are obviously not within the Level II Threshold source criteria range.

Ozone (O_3) differs from other criteria pollutants in that it is not typically emitted directly into the atmosphere. O_3 is formed in the atmosphere through reactions of VOCs, NOx, and sunlight. Atmospheric dispersion models used in stationary source air permitting analyses cannot be used to estimate O_3 impacts resulting from VOC and NOx emissions from an industrial facility. O_3 concentrations resulting from area-wide emissions are predicted by using more complex airshed models such as the Community Multi-Scale Air Quality (CMAQ) modeling system. Use of the CMAQ model is very resource-intensive and DEQ asserts that performing a CMAQ analysis for a particular permit application is not typically a reasonable or necessary requirement for air quality permitting. Addressing secondary formation of O_3 within the context of permitting a new stationary source has been somewhat addressed in EPA regulation and policy. As stated in a letter from Gina McCarthy of EPA to Robert Ukeiley, acting on behalf of the Sierra Club (letter from Gina McCarthy, Assistant Administrator, United States Environmental Protection Agency, to Robert Ukeiley, January 4, 2012):

> *. . . footnote 1 to sections 51.166(I)(5)(I) of the EPA's regulations says the following: "No de minimis air quality level is provided for ozone. However, any net emission increase of 100 tons per year or more of volatile organic compounds or nitrogen oxides subject to PSD would be required to perform an ambient impact analysis, including the gathering of air quality data."*
>
> *The EPA believes it unlikely a source emitting below these levels would contribute to such a violation of the 8-hour ozone NAAQS, but consultation with an EPA Regional Office should still be conducted in accordance with section 5.2.1.c. of Appendix W when reviewing an application for sources with emissions of these ozone precursors below 100 TPY."*

DEQ determined it was not appropriate or necessary to require a quantitative source-specific O_3 impact

analysis because allowable emission estimates of VOCs and NOx are below the 100 tons/year threshold. Additionally, VOC emissions satisfied BRC exemption criteria.

3.1.2 TAPs Modeling Applicability

TAP emission regulations under Idaho Air Rules Section 210 are only applicable for new or modified sources constructed after July 1, 1995.

Facility-wide emissions of Formaldehyde, Arsenic (As), Cadmium (Cd), Hexavalent Chromium (Cr6+), and Nickel (Ni) exceed the applicable emission screening levels (ELs) of Idaho Air Rules Section 586. Air impact modeling analyses were then required to demonstrate that maximum impacts of these five TAPs are below applicable ambient increment standards expressed in Idaho Air Rules Section 585 and 586 as AACs and AACCs.

All the modeled TAPs are carcinogenic and are regulated on a long-term averaging basis. Therefore, the appropriate emission rates for impact analyses are maximum annual emissions, expressed as an average pound/hour value over an 8,760-hour period.

The DEQ permit writer determined emissions from the boilers are not subject to TAP requirements because the boilers are regulated under 40 CFR 60, 61, or 63 (emissions subject to 40 CFR 60, 61, or 63 are excluded from the TAP requirements as described in Section 2.5 of this memorandum).

Table 4 provides a summary of TAP emission increases for the project for those TAPs that had an increase exceeding the ELs of Idaho Air Rules Section 585 or 586.

Table 4. TAP EMISSION INCREASES THAT TRIGGER MODELING

Toxic Air Pollutant	Emissions (lb/hr)[a]	Screening Emissions Level (lb/hr)
Formaldehyde[b]	2.15E-03	5.10E-04
Arsenic[b]	5.72E-06	1.50E-06
Cadmium[b]	3.15E-05	3.70E-06
Chromium (VI)[b]	2.00E-06	5.60E-07
Nickel[b]	6.01E-05	2.70E-05

a. Pounds per hour.
b. Carcinogenic TAP. ELs are annual maximum emissions expressed as pounds/hour. The emissions rate is the annual emissions divided by 8,760 hours/year.

3.1.3 Emission Release Parameters

Table 5 lists emission release parameters, including stack height, stack diameter, exhaust temperature, and exhaust velocity for emission sources modeled in the air impact analyses. Emission point release parameters were based on information provided by the applicant or DEQ assumptions based on similar sources with a margin of conservatism (less favorable dispersion characteristics such as shorter stack heights, lower flow volumes, etc). All emission release parameters appear to be within reasonably expected values for the sources identified.

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Table 5. POINT SOURCE STACK PARAMETERS								
Release Point	Description	UTM[a] Coordinates		Stack Height (m)	Stack Gas Flow Temp. (K)[c]	Stack Gas Flow Velocity (m/sec)[d]	Modeled Stack Diameter (m)	Orient. of Release[e]
		Easting-X (m)[b]	Northing-Y (m)					
BLR1A	new boiler	437146.5	4854239.2	24.38	425.37	13.94	1.22	V
BLR2A	new boiler	437146.5	4854229.8	24.38	425.37	13.94	1.22	V
FLK_N	North Flake scrubber	437087.1	4854272.4	24.38	319.26	17.59	1.52	V
FLK_S	South Flake scrubber	437087.1	4854260.2	24.38	319.26	17.59	1.52	V
P4A	new belt dryer	437070.6	4854306.4	12.19	335.93	13.63	0.91	V
P4BCD	new belt dryer	437072.3	4854314.8	12.19	335.93	9.99	1.06	V
KIPPER	existing boiler remove	437101.7	4854362.3	20.12	327.04	10.61	1.22	V
BOILER1	existing – Boiler	437095.6	4854371.5	10.97	533.15	14.35	0.91	V
BOILER2	existing – Boiler	437090.4	4854371.5	19.51	505.37	14.69	0.91	V
7020	Process A Dryer	437044.6	4854326.4	21.95	309.26	16.97	0.51	H
7101	Process A Dryer	437040.5	4854344.9	21.56	352.04	14.21	1.08	V
7102	Process A Dryer	437036.0	4854351.8	21.51	340.37	13.63	1.08	V
7019	Process A Dryer	437043.4	4854324.5	20.24	330.37	18.17	0.79	V
7001	Process A Dryer	437034.7	4854324.5	20.06	305.37	10.62	0.41	V
7027	Process A Dryer	437034.8	4854326.5	20.83	302.59	10.84	0.36	V
7006	Process A Dryer	437034.2	4854333.7	19.96	305.37	15.24	0.27	V
5037	Main Bldg vent	437031.6	4854335.6	20.83	327.59	13.51	0.67	V
5034	Main Bldg vent	437030.2	4854337.4	20.73	338.71	13.69	0.22	V
4000	Main Bldg vent	437066.1	4854336.1	15.57	337.04	22.95	0.85	V
228	Process B Dryer	437065.5	4854314.5	11.58	329.26	5.81	1.28	V
234	Process B Dryer	437066.0	4854302.7	10.58	342.59	10.76	1.17	V
M33	Process B Dryer	437055.2	4854319.6	12.19	344.26	16.44	0.51	V
M44	Process B Dryer	437053.2	4854317.6	12.19	418.15	7.64	0.38	V
M56	Process B Dryer	437054.2	4854304.6	9.75	349.82	16.18	0.30	V
M62	Process B Dryer	437052.2	4854304.6	9.75	333.15	12.42	0.38	V
M86	Main Bldg vent	437047.2	4854294.6	8.23	331.48	15.26	0.51	V
613/614	existing – Belt Dryer	437072.3	4854314.8	8.63	333.15	16.83	0.63	V
615/616	existing – Belt Dryer	437070.6	4854306.4	7.95	362.04	13.76	0.66	V
638	existing – Belt Dryer	437071.0	4854296.2	8.81	345.37	8.83	0.42	V
707	Main Bldg vent	437084.0	4854266.8	5.11	305.37	14.76	0.21	H

725	Main Bldg vent	437084.0	4854260.8	4.22	305.37	32.86	0.12	H
8	Process B Dryer	437026.4	4854310.3	6.61	300.37	7.49	0.41	H
5001	Process B Dryer	437032.9	4854324.5	20.73	297.59	7.62	0.22	V
5000	Process B Dryer	437026.4	4854288.3	8.08	299.82	23.03	0.13	H
432	Process B Dryer	437026.4	4854295.6	7.04	299.82	12.05	0.15	H
322	Process B Dryer	437020.5	4854302.3	3.00	355.37	11.02	0.15	H
572	Process B Dryer	437098.7	4854388.8	4.72	305.37	15.24	0.17	V

a. Universal Transverse Mercator.
b. Meters.
c. Kelvin.
d. Meters per second.
e. Vertical uninterrupted, rain-capped, or horizontal release.

Table 6 shows the volume source parameters as modeled by CCE for the AMU sources. After review, DEQ made some revisions to assure compliance with the NAAQS. The building heights of the AMU sources in the main building and old boiler structures were reduced based upon the structure heights at the sources proposed locations. Also, the horizontal dimensions are calculated by dividing the average building width by either 4.3 (for a single source), or by 2.15 (for a series of sources). CCE used the 2.15 factor for all the volume sources, likely because the sources are grouped together in a bundle of buildings. Because the receiving building is somewhat separated from the main structures, DEQ revised the factor from 2.15 to 4.3. DEQ reran sensitivity modeling with both sets of parameters to assure compliance. The possible revisions by DEQ did not alter the effect of the modeling results.

Table 6. VOLUME AND AREA SOURCE RELEASE PARAMETERS

Source	Description	UTM[a] Coordinates		Release Height (ft)	Horizontal Dimension (ft)	Vertical Dimension (ft)
		Easting - X (m)[b]	Northing - Y (m)			
As Submitted by CCE						
AM_MAIN	existing main plant fugitive amu	437046.72	4854305.62	63	149.5	29.3
AM_RCVG	receiving building fugitive amu	437084.35	4854415.25	23	74.4	10.7
AM_FLAKE	Flake area fugitive amu	437105.24	4854278.79	40	84.0	18.6
AM_BLROLD	old boilerhouse amu	437095.79	4854370.99	60	33.5	27.9
AM_BLRNEW	new boilerhouse amu	437138.61	4854229.42	31	47.0	14.4
AM_HTRS	Exist volume source for heaters	437051.28	4854302.3	31	64.0	29.0
As revised by DEQ						
AM_MAIN	existing main plant fugitive amu	437046.72	4854305.62	**46**[c]	149.5	**21.4**[c]
AM_RCVG	receiving building fugitive amu	437084.35	4854415.25	23	**37.4**[d]	10.7
AM_FLAKE	Flake area fugitive amu	437105.24	4854278.79	40	84.0	18.6
AM_BLROLD	old boilerhouse amu	437095.79	4854370.99	**25**[c]	33.5	**11.6**[c]
AM_BLRNEW	new boilerhouse amu	437138.61	4854229.42	31	47.0	14.4
AM_HTRS	Exist volume source for heaters	437051.28	4854302.3	31	64.0	29.0

[a.] Universal Transverse Mercator
[b.] Meters
[c.] Based on review on building heights with source locations
[d.] Based on a division factor of 4.3 vs 2.15

The emission rates for the criteria pollutants as modeled in the SIL analyses are listed in Table 7. These rates are modeled to determine what pollutants and averaging times are then modeled in a cumulative NAAQS impact analysis. CCE elected to select applicability with the Level II modeling thresholds and not assess impacts from CO. DEQ, due to the level of impacts (not the emissions) from the AMU sources, is stating that Level 1 modeling thresholds are the proper level of assessment to consider in this project. Therefore, DEQ also assessed the impacts from CO, and these emissions estimated by DEQ, are listed below. Additionally, the negative (credit) PM emissions from the Kipper Boiler and the existing AMU source are derived from a different (and more negatively conservative) emission factor than when assessing the proposed PTE emissions. Emission factors need to be consistent when taking credit for changes not attributable to proposed emission control equipment. Therefore, the negative credits from these two sources were not included in the revised SIL modeling performed by DEQ.

Table 7. Criteria Emission Rates as Modeled in SIL Analyses

Source ID	Description	24-Hour $PM_{2.5}$ (lb/hr) [a]	Annual $PM_{2.5}$ (lb/hr) [a]	24-hour PM_{10} (lb/hr) [a]	1 and 8 Hour CO (lb/hr) [a]
BLR1A	new boiler	0.042	0.0418	0.051	*7.3719*
BLR2A	new boiler	0.042	0.0418	0.051	*7.3719*
FLK_N	North Flake scrubber	0.454	0.1043	0.455	*0.3301*
FLK_S	South Flake scrubber	0.454	0.1043	0.455	*0.3301*
P4A	new belt dryer	0.415	0.4148	0.415	*1.0666*
P4BCD	new belt dryer	1.726	1.7260	1.726	*1.1655*
KIPPER	existing boiler remove	-2.732	-11.733	-2.732	*8.9149*
BOILER1	existing – Boiler	-0.39	-0.3881	-0.39	*-4.2800*
BOILER2	existing – Boiler	0	0.0000	0	*0.0000*
7020	Process A Dryer	0.031	0.0251	0.031	*0.1447*
7101	Process A Dryer	0.186	0.1836	0.186	*0.4808*
7102	Process A Dryer	0.186	0.1836	0.186	*0.4769*
7019	Process A Dryer	0.099	0.0989	0.099	*0.3443*
7001	Process A Dryer	0.019	0.0142	0.019	*0.0587*
7027	Process A Dryer	0.003	0.0023	0.003	*0.0463*
7006	Process A Dryer	0.01	0.0068	0.01	*0.0380*
5037	Main Bldg vent	0	2.28E-04	0.001	*0.0197*
5034	Main Bldg vent	0	0	0	*0.1903*
4000	Main Bldg vent	0.001	4.57E-04	0.001	*0.5039*

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228	Process B Dryer	0.001	2.28E-04	0.001	*0.2962*
234	Process B Dryer	0.001	4.57E-04	0.001	*0.4396*
M33	Process B Dryer	0	2.28E-04	0	*0.1248*
M44	Process B Dryer	0	0	0	*0.0271*
M56	Process B Dryer	0	0	0	*0.0439*
M62	Process B Dryer	0	0	0	*0.0553*
M86	Main Bldg vent	0	2.28E-04	0	*0.1204*
613/614	existing – Belt Dryer	-0.85	-0.8539	-0.85	*0.0000*
615/616	existing – Belt Dryer	-0.24	-0.2397	-0.24	*0.0000*
638	existing – Belt Dryer	-1.09	-1.0959	-1.09	*0.0000*
707	Main Bldg vent	0	0	0	*0.0225*
725	Main Bldg vent	0	0	0	*0.0160*
8	Process B Dryer	0	4.57E-04	0	*0.0421*
5001	Process B Dryer	0.002	0.0021	0.003	*0.0125*
5000	Process B Dryer	0	4.57E-04	0	*0.0127*
432	Process B Dryer	0	4.57E-04	0	*0.0095*
322	Process B Dryer	0.002	0.0023	0.002	*0.0074*
572	Process B Dryer	0.001	6.85E-04	0.001	*0.0139*
AM_MAIN	existing main plant fugitive amu	7.56E-04	0.014	0.008	*2.8845*
AM_RCVG	receiving building fugitive amu	1.26E-04	0.003	0.002	*0.4600*
AM_FLAKE	Flake area fugitive amu	2.52E-04	0.003	0.002	*0.2703*
AM_BLROLD	old boilerhouse amu	1.26E-04	0.003	0.002	*0.7800*
AM_BLRNEW	new boilerhouse amu	1.26E-04	0.001	0.001	*0.1187*
AM_HTRS	Exist volume source for heaters	-0.328	-0.715	-0.328	

[a] Pounds/hour.
[b] Modeled as negative rates for SIL modeling assessment only (removed sources).

Emissions used in the cumulative NAAQS modeling analyses are listed in Table 8. It should be noted that these values are identical to those listed in Table 23 (and in the Emission Inventory) of the submitted Ambient Impact Analyses report, as well as in the modeling files for the "Boiler 2 " scenario. The rates in the "Kipper Boiler" scenario modeling files were slightly less in magnitude. DEQ replaced the data in the "Kipper Boiler" version with the data listed in Table 8 for its revised modeling analyses, again, to assure compliance with the NAAQS.

3.2 Background Concentrations

Background concentrations are used if a cumulative NAAQS impact analysis is needed to demonstrate compliance with applicable NAAQS. Background design values (DV) for annual and 24-hour $PM_{2.5}$, 24-hour PM_{10}, annual and 1-hour NO_2 , 1-hour and 8-hour CO, and 3-hour SO_2 were obtained from NW-AIRQUEST (http://lar.wsu.edu/nw-AIRQUEST/lookup.html) using the project site coordinates. These background air pollutant levels are based on regional scale air pollution modeling of pollutants in Washington, Oregon, and Idaho, with modeling results adjusted according to available monitoring data.

The values from NW-AIRQUEST are listed in Table 9.

Table 8. Criteria Emission Rates as Modeled in NAAQS Analyses			
Source ID	**Description**	**1-hour NO_2 (lb/hr)** [a]	**Annual NO_2 (TPY)** [b]
BLR1A	new boiler	1.889	8.046
BLR2A	new boiler	1.889	8.046
FLK_N	North Flake scrubber	0.271	0.596
FLK_S	South Flake scrubber	0.271	0.596
P4A	new belt dryer	0.378	1.415
P4BCD	new belt dryer	0.378	1.415
KIPPER[c]	existing boiler remove	21.580	31.510
BOILER2[c]	existing – Boiler	4.890	21.419
7020	Process A Dryer	0.047	0.101
7101	Process A Dryer	0.488	1.796
7102	Process A Dryer	0.486	1.791
7019	Process A Dryer	0.450	1.721
7001	Process A Dryer	0.019	0.044
7027	Process A Dryer	0.015	0.035
7006	Process A Dryer	0.012	0.026
5037	Main Bldg vent	0.062	0.136
5034	Main Bldg vent	0.006	0.013
4000	Main Bldg vent	0.164	0.359
228	Process B Dryer	0.576	2.330
234	Process B Dryer	0.463	1.721
M33	Process B Dryer	0.121	0.429
M44	Process B Dryer	0.089	0.368
M56	Process B Dryer	0.064	0.232
M62	Process B Dryer	0.068	0.241
M86	Main Bldg vent	0.039	0.088
707	Main Bldg vent	0.006	0.018
725	Main Bldg vent	0.004	0.013
8	Process B Dryer	0.011	0.031
5001	Process B Dryer	0.003	0.009
5000	Process B Dryer	0.003	0.009
432	Process B Dryer	0.002	0.009
322	Process B Dryer	0.002	0.004
572	Process B Dryer	0.004	0.009

AM_MAIN	existing main plant fugitive amu	0.936	2.050
AM_RCVG	receiving building fugitive amu	0.182	0.399
AM_FLAKE	Flake area fugitive amu	0.222	0.486
AM_BLROLD	old boilerhouse amu	0.150	0.329
AM_BLRNEW	new boilerhouse amu	0.098	0.215

a. Pounds/hour.
b. Tons per year.
c. The Kipper Boiler and Boiler 2 are not operated concurrently; therefore, two separate scenarios were modeled.

Table 9. DEQ-RECOMMENDED AMBIENT BACKGROUND CONCENTRATIONS

Pollutant	Averaging Period	Background Concentration ($\mu g/m^3$)[a,b]
$PM_{2.5}$[c]	24-hr	16.8
	Annual	6.2
PM_{10}[d]	24-hr	70.1
NO_2[e]	1-hr	44.9 (23.9ppb[f])
	Annual	8.6 (4.6 ppb)
CO[g]	1-hr	2257 (1980 ppb)
	8-hr	1197 (1050 ppb)
SO_2[h]	1-hr	13.1 (5 ppb)
	3-hr	17.2 (5.6 ppb)

a. Micrograms per cubic meter, except where noted otherwise.
b. NW AIRQUEST ambient background lookup tool, 2014-2017.
c. Particulate matter with an aerodynamic diameter of 2.5 microns or less.
d. Particulate matter with an aerodynamic diameter of 10 microns or less.
e. Nitrogen dioxide.
f. Parts per billion by volume.
g. Carbon monoxide.
h. Sulfur dioxide.

3.3 Impact Modeling Methodology

This section describes the modeling methods used by the applicant and DEQ to demonstrate preconstruction compliance with applicable air quality standards.

3.3.1 General Overview of Impact Analyses

REXBAF and CCE performed the project-specific air pollutant emission inventory and air impact analyses that were submitted with the application. The submitted information/analyses, in combination with results from DEQ's air impact analyses, demonstrate compliance with applicable air quality standards to DEQ's satisfaction, provided the facility is operated as described in the submitted application and in this memorandum.

Table 10 provides a brief description of parameters used in the modeling analyses.

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Table 10. MODELING PARAMETERS		
Parameter	**Description/Values**	**Documentation/Addition Description**
General Facility Location	Rexburg, Idaho	The area is an attainment or unclassified area for all criteria pollutants.
Model	AERMOD	AERMOD with the PRIME downwash algorithm, version 18081.
Meteorological Data	Rexburg surface data; Boise upper air data	See Section 3.3.4 of this memorandum for additional details of the meteorological data.
Terrain	Considered	1 arc second National Elevation Dataset (NED) was acquired from the USGS for the surrounding area. AERMAP version 18081 was used to process terrain elevation data for all buildings and receptors. See Section 3.3.5 for more details.
Building Downwash	Considered	Considered in a generic method. See Section 3.3.6.
NOx Chemistry	Tier 2 / Tier32	Tier 2 Ambient Ratio Method (ARM2) assumes default minimum (0.5) and maximum (0.9) ambient ratios of NO_2/NOx. See Section 3.3.7. Used for cumulative NAAQS analyses CCE used Tier 3 PVMRM with NSR/NO2 ratios set to 0.3 values, below the default of 0.5. DEQ reran with default of 0.5
Receptor Grid	**SIL Analysis** The selection of receptors for use in the SIL Analyses is as follows (see Section 3.3.9):	
	Grid 1	25-meter spacing along the ambient air boundary, extending out to 100 meters from the boundary
	Grid 2	100-meter spacing in a 1000 meter (easting) by 1000 meter (northing) grid centered on the facility
	Grid 3	250-meter spacing in a 3000 meter (easting) by 3000 meter (northing grid centered on the facility
	Cumulative NAAQS Impact Analyses The same receptor grid was used for the NAAQS Analyses as for the Significant Impact Level Analyses.	
	TAPs Analyses The same receptor grid was used for the TAPs Analyses as for the Significant Impact Level Analyses.	

3.3.2 Modeling Methodology

Project-specific modeling and other required impact analyses were generally conducted using data and methods described in the *Idaho Air Quality Modeling Guideline*[2].

3.3.3 Model Selection

Idaho Air Rules Section 202.02 requires that estimates of ambient concentrations be based on air quality models specified in Appendix W. The refined, steady-state, multiple-source, Gaussian dispersion model AERMOD was promulgated as the replacement model for ISCST3 in December 2005. AERMOD retains the single straight-line trajectory of ISCST3, but it includes more advanced algorithms to assess turbulent mixing processes in the planetary boundary layer for both convective and stable stratified layers.

AERMOD version 18081 was used by DEQ for the modeling analyses to evaluate impacts of the facility. This version was the current version at the time the application was received by DEQ.

3.3.4 Meteorological Data

DEQ processed a meteorological dataset from Rexburg, Idaho (KXRE; station ID 726818-94194) covering the years 2011-2016. The year 2013 was not utilized because of significant missing ASOS data for that period. The upper air soundings required by AERMET were obtained from the Boise airport

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station (site ID 24131). Surface characteristics were determined by DEQ staff using AERSURFACE version 13016. DEQ modeling staff evaluated annual moisture conditions for the AERSURFACE runs based on THIRTY years of Rexburg, Idaho airport precipitation data. Conditions were determined to be "wet" for 2011, 2014, and 2016,. The years 2012 and 2015 were determined to be "average" for precipitation. Average moisture content is defined as within a 30 percentile of the 30-year mean of 11.2 inches. Calms were relatively low at less than 1 percent, and less than 1 percent of the data were missing from the 5-year record. AERMINUTE version 15272 was used to process Automated Surface Observing Systems (ASOS) wind data for use in AERMET. AERMET version 18081 was used to process surface and upper air data and to generate a model-ready meteorological data input file. The "adjust u star" (ADJ_U*) option was applied in AERMET to enhance model performance during low wind speeds under stable conditions. DEQ determined that these data are adequately representative of the meteorology at the BAF Rexburg facility for minor source permitting.

3.3.5 Effects of Terrain on Modeled Impacts

Submitted ambient air impact analyses used terrain data extracted from United States Geological Survey (USGS) National Elevation Dataset (NED) files.

The terrain preprocessor AERMAP version 18081 was used by CCE to extract the elevations from the NED files and assign them to receptors in the modeling domain in a format usable by AERMOD. AERMAP also determined the hill-height scale for each receptor. The hill-height scale is an elevation value based on the surrounding terrain which has the greatest effect on that individual receptor. AERMOD uses those heights to evaluate whether the emissions plume has sufficient energy to travel up and over the terrain or if the plume will travel around the terrain.

3.3.6 Facility Layout and Downwash

DEQ verified proper identification of the site location, equipment locations, and the ambient air boundary by comparing a graphical representation of the modeling input file to plot plans submitted in the application. Aerial photographs on Google Earth (available at https://www.google.com/earth) were also used to assure that horizontal coordinates were accurate as described in the application.

Potential downwash effects on emission plumes were accounted for in the model by using building dimensions and locations (locations of building corners, base elevation, and building heights). Included in the project are projected changes to the existing building structures. Therefore, detailed analyses were required to demonstrate the effective differences to modeling results of the existing building structures versus the proposed building additions. These changes are highlighted in Figure 1. Dimensions and orientation of proposed buildings were used as input to the Building Profile Input Program for the Plume Rise Model Enhancements downwash algorithm (BPIP-PRIME version 04274) to calculate direction-specific dimensions and Good Engineering Practice (GEP) stack height information for input to AERMOD for both existing structures (and modified or removes sources) and proposed structures (and new and remaining sources) .

3.3.7 NOx Chemistry

The atmospheric chemistry of NO, NO_2, and O_3 complicates accurate prediction of NO_2 impacts resulting from NOx emissions. The conversion of NO to NO_2 can be conservatively addressed through the use of several methods as outlined in a *2014 EPA NO_2 Modeling Clarification Memorandum.*[3] The guidance outlines a three-tiered approach:

- Tier 1 – assume full conversion of NO to NO_2 where total NOx emissions are modeled and modeled impacts are assumed to be 100 percent NO_2.

- Tier 2 – use an ambient ratio to adjust impacts from the Tier 1 analysis.

- Tier 3 – use a detailed screening method to account for $NO/NO_2/O_3$ chemistry such as the Ozone Limiting Method (OLM) or the Plume Volume Molar Ratio Method (PVMRM).

CCE used the Tier3 conversion approach to assess NO_x impacts for the NAAQS analyses to determine if the cumulative modeling impacts were protective of the 1 hour and annual NAAQS. CCE selected to not perform SIL analyses for NO_2. CCE elected to use the the Plume Volume Molar Ratio Method (PVMRM) method. They also submitted a methodology which utilized non-default minimum and maximum NO_2/NO_x ratios of 0.3 and 0.9, respectively. Because these are not the default values, and there are not existing matching source data in EPA's "NSR in-stack ratio database", CCE provided documentation to support justifying their usage. Per modeling guidelines, DEQ would need to assess the data (in detail) and approve the non-standard approach. DEQ had discussed this approach directly with CCE and in comments to the emails from Steven Nelson, dated July 2019. DEQ agreed to consider the approach, and noted that the data looked promising. After the preliminary modeling review, which incorporated some revisions by DEQ to the modeling inputs, DEQ reran the NO_2 modeling files. DEQ initially ran the files using EPA's default ARM2 approach, with default 0.5 and 0.9 NO_2/NO_x ratios. The results of the modeling analyses showed compliance with NO_2 NAAQS for both modeling scenarios (with Kipper Boiler only, and with Boiler2 only). Therefore, DEQ is accepting the modeling using the EPA defaults of ARM2 as showing compliance with NO_2 NAAQS. DEQ appreciates the inclusion of the NO_2/NO_X ratio data, but elects at this time to not go through the process of accepting it for this application, as it is not required.

3.3.8 Ambient Air Boundary

Ambient air is defined in Section 006 of the Idaho Air Rules as "that portion of the atmosphere, external to buildings, to which the general public has access." To exclude areas of the site from consideration as ambient air, the permittee must have the legal and practical ability to control access to such areas of the site. The applicant uses fencing and signage to exclude access from the general public.

3.3.9 Receptor Network

The receptor grid used in DEQ's analyses met the minimum recommendations specified in the *Idaho Air Quality Modeling Guideline*[2] and DEQ determined that it was adequate to resolve maximum modeled impacts.

Table 10 describes the receptor network used in the submitted modeling analyses. The receptor grids used in the model provided good resolution of the maximum design concentrations for the project and provided extensive coverage. The full receptor grid was used for SIL, NAAQS, and TAPs ambient air impact analyses. DEQ determined that the receptor network was effective in reasonably assuring compliance with applicable air quality standards at all ambient air locations.

3.3.10 Good Engineering Practice Stack Height

An allowable good engineering practice (GEP) stack height may be established using the following equation in accordance with Idaho Air Rules Section 512.03.b:

H = S + 1.5L, where:

H = good engineering practice stack height measured from the ground-level elevation at the base of the stack.

S = height of the nearby structure(s) measured from the ground-level elevation at the base of the stack.

L = lesser dimension, height or projected width, of the nearby structure.

All sources from REXBAF are below GEP stack height. Therefore, consideration of downwash caused by nearby buildings was required.

4.0 NAAQS and TAPs Impact Modeling Results

4.1 Results for NAAQS Analyses

A NAAQS impact analysis was performed for REXBAF. Idaho Air Rules Section 203.02, requiring air impact analyses demonstrating compliance with NAAQS, is applicable to pollutants having project emissions increase that are greater than Level I modeling thresholds.

4.1.1 Significant Impact Level Analyses

Table 11 provides results for the significant impact level (SIL) analyses. Maximum predicted impacts from the facility for those pollutants assessed were all below the SILs for each pollutant. CCE did not model NO_2 for SIL analyses. A cumulative NAAQS impact analysis was performed for this criteria pollutant.

4.1.2 Cumulative NAAQS Impact Analyses

Table 12 provides results for the Cumulative NAAQS Impact analysis. For each modeled pollutant, the total impact was calculated by adding the design value (DV) of the impact to the ambient background value. The sum was then compared to the NAAQS. Ambient impacts for the facility, when combined with approved ambient backgrounds, were below the NAAQS at all receptors where the facility-modeled impacts exceeded the SIL. The annual ambient impact was not correctly included in the modeling report submitted with the application. The value has been correctly added in these results. Both the results from DEQ's revised sensitivity modeling and those from the submitted report are listed.

Table 11. RESULTS FOR SIGNIFICANT IMPACT LEVEL ANALYSES

Pollutant	Averaging Period	Maximum Modeled Concentration ($\mu g/m^3$)[a]	Significant Contribution Level ($\mu g/m^3$)	Impact Percentage of Significant Contribution Level	Cumulative NAAQS Analysis Required?	UTM[b,c] Easting (m)	UTM[c] Northing (m)
$PM_{2.5}$[d]	24-hour	0.78(0.3)[g]	1.2	65%	No	436740	4854095
	Annual	0.0 (0.0)[g]	0.2	0%	No		
PM_{10}[e]	24-hour	0.9(0.4)[g]	5.0	18%	No	437320	4854433
CO[f]	1-hour	303(NA)	2,000	15%	No	437207	4854244
	8-hour	143(NA)	500	29%	No	436765	4854094

a. Micrograms per cubic meter.
b. Universal Transverse Mercator, NAD83, Zone 12
c. Location of maximum modeled impacts.
d. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
e. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
f. Carbon monoxide.
g. Results in parantheses are from submitted Ambient Impact Report, July 2019

Table 12. RESULTS FOR CUMULATIVE NAAQS IMPACT ANALYSES

Pollutant	Averaging Period	Modeled Design Value Concentration ($\mu g/m^3$)[a]	Background Concentration ($\mu g/m^3$)	Total Ambient Impact ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent of NAAQS
NO_2[b]	1-hour					
Kipper Boiler Scenario		133.3	44.9	178.2(143)[c]	188	94.7%
Boiler 2 Scenario		89.2	44.9	134.1	188	71.3%
NO_2[b]	Annual	9.1(9.4)	8.6	17.7	100	18%

a. Micrograms per cubic meter.
b. Nitrogen dioxide
c. Results in parantheses are from submitted Ambient Impact Report, July 2019

4.2 Results for TAPs Impact Analyses

Dispersion modeling was required to demonstrate compliance with TAP increments specified by Idaho Air Rules Section 585 and 586 for those TAPs with project-related emission increases exceeding screening emission levels (ELs). Table 11 lists the maximum modeled impacts for specific TAPs. All modeled impacts are below applicable AACs and AACCs.

Table 11. TAP AIR IMPACT ANALYSIS RESULTS

TAP	Maximum Modeled Impact ($\mu g/m^3$)[a]	AAC or AACC ($\mu g/m^3$)	Percent of AAC/ AACC
Formaldehyde	0.0026	0.077	3.3%
Arsenic	6.8E-06	2.3E-04	3.0%
Cadmium	3.7E-05	5.6E-04	6.7%
Chromium (VI)	2.4E-06	8.3E-05	2.9%
Nickel	7.2E-05	4.2E-03	1.7%

d. Micrograms per cubic meter.
e. Carcinogenic TAP. Modeled impact and AACC represent annual or period-average concentration.

5.0 Conclusions

The information submitted with the PTC application, combined with DEQ air impact analyses, demonstrated to DEQ's satisfaction that emissions from REXBAF will not cause or significantly contribute to a violation of any applicable ambient air quality standard or TAP increment.

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References

1. *Policy on NAAQS Compliance Demonstration Requirements.* Idaho Department of Environmental Quality Policy Memorandum. July 11, 2014.

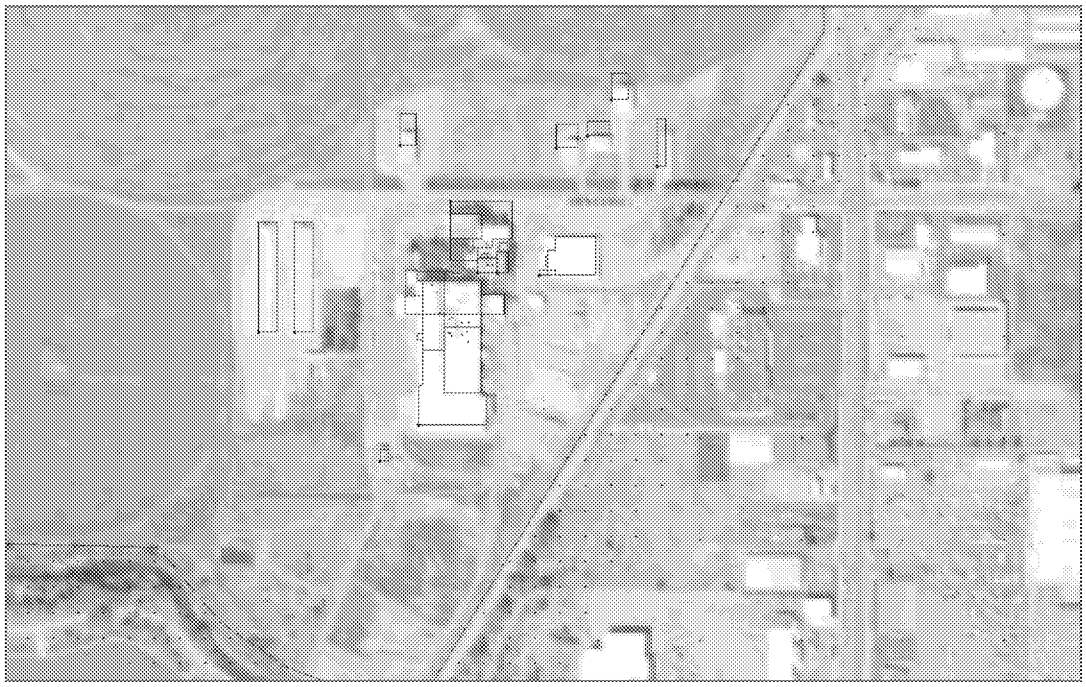
2. *State of Idaho Guideline for Performing Air Quality Impact Analyses*. Idaho Department of Environmental Quality. September 2013. State of Idaho DEQ Air Doc. ID AQ-011. Available at http://www.deq.idaho.gov/media/1029/modeling-guideline.pdf.

3. *Clarification on the Use of AERMOD Dispersion Modeling for Demonstrating Compliance with the NO_2 National Ambient Air Quality Standard*. Office of Air Quality Planning and Standards. Air Quality Modeling Group. Research Triangle Park, NC. Guidance memorandum from R. Chris Owen and Roger Brode to Regional Dispersion Modeling Contacts. September 30, 2014.

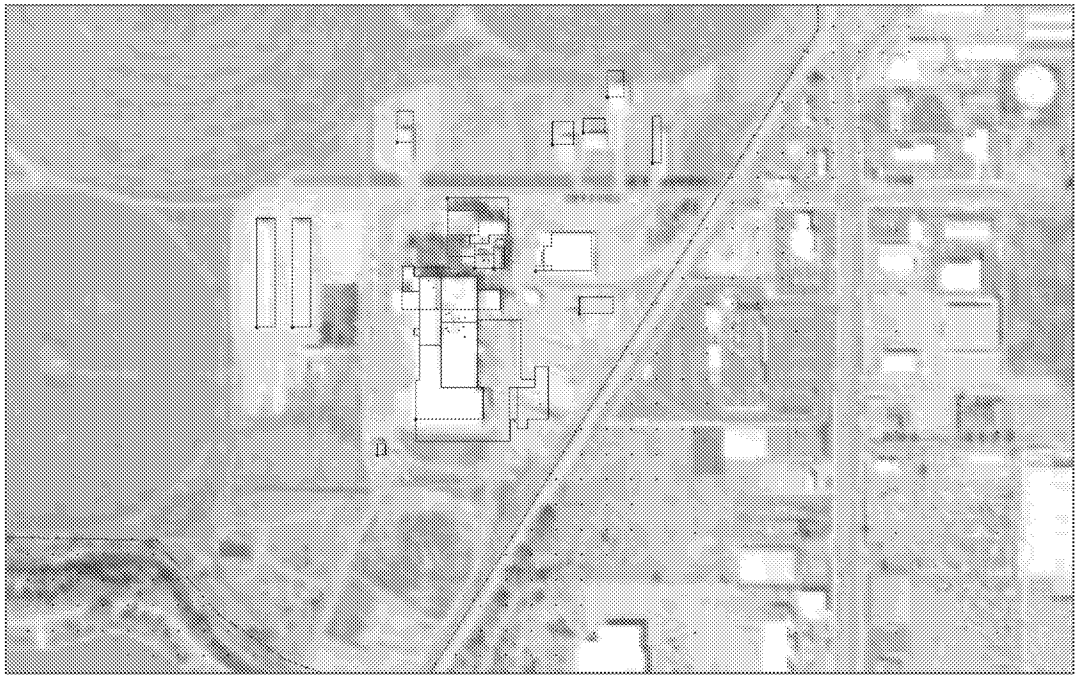
ED_013256A_00004260-00025

Figure 1. BPIP-PRIME Layouts

BAF Rexburg - BPIP-PRIME with existing Buildings



BAF Rexburg - BPIP-PRIME with proposed Buildings



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Message

From: Pettie, Brianna N (DEC) [brianna.pettie@alaska.gov]
Sent: 3/26/2021 9:09:23 PM
To: frederick.werth@nutrien.com
CC: Plosay, James R (DEC) [jim.plosay@alaska.gov]; Simpson, Aaron J (DEC) [aaron.simpson@alaska.gov]; Jones, Dave F (DEC) [dave.jones2@alaska.gov]; Dunn, Patrick E (DEC) [patrick.dunn@alaska.gov]; Olds, Jason R (DEC) [jason.olds@alaska.gov]; Wiltse, Denise V (DEC) [denise.wiltse@alaska.gov]; Coss, Pablo M (DEC) [Moses.coss@alaska.gov]; Saaid, Adam H (DEC) [adam.saaid@alaska.gov]; Turner, Thomas E (DEC) [tom.turner@alaska.gov]; Pefley, Alan T (DEC) [alan.pefley@alaska.gov]; dave.jordan@erm.com; Hardesty, Doug [Hardesty.Doug@epa.gov]; catherine_collins@fws.gov; andrea_stacy@nps.gov; ted.hartman@nutrien.com
Subject: AQ0083CPT07 Final Permit Trans Ltr, Final Permit, Final TAR, & RTC; Agrium US Inc, Kenai Nitrogen Operations, 03.26.21
Attachments: AQ0083CPT07 Final Permit Trans Ltr 03.26.21.pdf; AQ0083CPT07 Final Permit 03.26.21.pdf; AQ0083CPT07 Final TAR 03.26.21.pdf; AQ0083CPT07 RTC 03.26.21.pdf

All recipients,

Please review or file the attached document(s) as required. Thank you.

Best,

Brianna Pettie
Office Assistant II
DEC - Division of Air Quality
PO Box 111800, Juneau, AK 99811-1800
Phone - (907) 465-5104 | Email - brianna.pettie@alaska.gov

DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY CONTROL CONSTRUCTION PERMIT

Permit AQ0083CPT07 **Final Date – March 26, 2021**
Rescinds Permit AQ0083CPT06

The Alaska Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Construction Permit AQ0083CPT07 to the Permittee listed below.

Operator and Permittee:	Agrium, U.S. Inc. P.O. Box 575 Kenai, Alaska 99611
Owner:	Agrium U.S. Inc.
Stationary Source:	Kenai Nitrogen Operations
Location:	Latitude: 60.6750° North; Longitude: 151.3806° West
Physical Address:	Mile 21 Kenai Spur Highway Kenai, Alaska 99611
Permit Contact:	Ted Hartman (913) 302-7469 ted.hartman@nutrien.com
Project:	Establish Kenai Nitrogen Operations Facility

The project is classified under 18 AAC 50.306 as a Prevention of Significant Deterioration (PSD) major stationary source 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). As required by AS 46.14.120(c) the Permittee shall comply with the terms and conditions of this permit.

This permit satisfies the obligation of the Permittee to obtain a construction permit under 18 AAC 50. As required by AS 46.14.120(c), the Permittee shall comply with the terms and conditions of this permit.

for: James R. Plosay, Manager
Air Permits Program

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Section 1 Emission Unit Inventory

Emission Unit (EU) Authorization. The Permittee is authorized to install and operate the EUs listed in Table 1 in accordance with the terms and conditions of this permit. The information in Table 1 is for identification purposes only, unless otherwise noted in the permit. The specific EU descriptions do not restrict the Permittee from replacing an EU identified in Table 1.

Table 1 – Stationary Source Emission Units

	EU ID	Tag Number	Source Description	Fuel Type	Rating/size	Install Date
Ammonia Plant #4	11	B-609	Ammonia Tank System Flare		1.25 MMBtu/hr	1995
	12	B-201	Primary Reformer	Fuel Gas & NG	1350 MMBtu/hr	1976
	13	B-200	Startup Heater	NG	101 MMBtu/hr	1976
	14	D-207	CO_2 Vent	N/A	90 tons/hr (NH_3)	1976
	15	H-205	Organic Sulfur Removal Unit Vent	N/A	N/A	1976
	16	H-269	Amine Fat Flasher Vent	N/A	N/A	1976
	17	F-263	PC Stripper Surge Tank Vent	N/A	N/A	1976
	19	C-200	H_2 Vent Stack (dry gas vent)	N/A	N/A	1976
	20	H-260	PC Stripper Steam KO Drum	N/A	N/A	1976
	21	F-287	Ammonia Drain Tank Vent	N/A	N/A	1976
	22	B-502	Plants 4 and 5 Small Flare Pilot	NG& NH_3	1.25 MMBtu/hr	1995
			Plants 4 and 5 Small Flare Flaring Event		1,200 lb/hr NH_3	
	23	B-501	Plants 4 and 5 Emergency Flare Pilot	NG& NH_3	0.4 MMBtu/hr	1995
			Plants 4 and 5 Emergency Flare Flaring Event		30,000 lb/hr NH_3	
Urea Plant #5	35	C-560A	Granulator A/B Scrubber Exhaust Vent Stack	N/A	50 tons/hr (urea)	1976
	36	C-560B	Granulator C/D Scrubber Exhaust Vent Stack	N/A	50 tons/hr (urea)	1976
	37	D- 515	Atmospheric Absorber Final Scrubber	N/A	N/A	1976
	38	D-511	Inerts Vent Scrubber	N/A	N/A	1976
	39	E-535	After Condenser Exchanger	N/A	N/A	1976
	40	E-711	Cooling tower	N/A	15,000 gal/min	1976
	41-41C	multiple	Tank Scrubber	N/A	N/A	multiple
Utility Plant #3 and # 6	44a	6B-708A	Cleaver Brooks Package Boiler	NG	243 MMBtu/hr	TBD
	47-47D	multiple	Urea and Ammonia Loading Wharf	N/A	1000 tons/hr	multiple
	48a	6B-708B	Cleaver Brooks Package Boiler	NG	243 MMBtu/hr	TBD
	49a	6B-708C	Cleaver Brooks Package Boiler	NG	243 MMBtu/hr	TBD
	50	B-705A	Certified & Nebraska Co. Waste Heat Boiler	NG	46.7 MMBtu/hr	1986
	51	B-705B	Certified & Nebraska Co. Waste Heat Boiler	NG	46.7 MMBtu/hr	1986
	52	B-705C	Certified & Nebraska Co. Waste Heat Boiler	NG	46.7 MMBtu/hr	1986
	53	B-705D	Certified & Nebraska Co. Waste Heat Boiler	NG	46.7 MMBtu/hr	1986
	54	B-705E	Certified & Nebraska Co. Waste Heat Boiler	NG	46.7 MMBtu/hr	1986
	55a	GGT-744A	Solar Turbine/Generator Set	NG	55.4 MMBtu/hr	TBD
	56a	GGT-744B	Solar Turbine/Generator Set	NG	55.4 MMBtu/hr	TBD
	57a	GGT-744C	Solar Turbine/Generator Set	NG	55.4 MMBtu/hr	TBD
	58a	GGT-744D	Solar Turbine/Generator Set	NG	55.4 MMBtu/hr	TBD
	59a	GGT-744E	Solar Turbine/Generator Set	NG	55.4 MMBtu/hr	TBD
	60	F-791	Deaerator Vent	N/A	N/A	1986
	61	F-711	Degasifier Vent	N/A	N/A	1976
	65	GM-616D	Diesel Fired Well Pump	Diesel	2.7 MMBtu/hr	1966
	66	G-613B	Gasoline Fired Fire Pump Engine	Gasoline	2.1 MMBtu/hr	1978

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1. The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement EU, including any applicable minor or construction permit requirements.

2. The Permittee shall commence[1] construction of the modification to the stationary source authorized under Construction Permit AQ0083CPT07 within 18 months of the issuance of the permit[2] unless granted an extension in writing from the Department.

[1] Commence has the meaning given in 40 C.F.R. 52.21(b)(9).
[2] See: 40 C.F.R. 52.21(r)

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Section 2 Fee Requirements

3. **Fee Requirements.** The Permittee shall pay to the Department all assessed permit fees. Fee rates are set out in 18 AAC 50.400 – 420.

4. **Assessable Emissions.** For each period from July 1 through the following June 30, the Permittee shall pay to the Department an annual emission fee based on the stationary source's assessable emissions, as determined by the Department under 18 AAC 50.410.[3] The Department will assess fees per ton of each air pollutant that the stationary source emits or has the potential to emit in quantities 10 tons per year or greater. The quantity for which fees will be assessed is the lesser of the stationary source's

   4.1 potential to emit of 1,286 tpy; or

   4.2 projected annual rate of emissions, based upon actual annual emissions for the most recent calendar year, or another 12-month period approved in writing by the Department, when demonstrated by credible evidence of actual emissions, based upon the most representative information available from one or more of the following methods:

      a. an enforceable test method described in 18 AAC 50.220;

      b. material balance calculations;

      c. emission factors from EPA's publication AP-42, Vol. I, adopted by reference in 18 AAC 50.035; or

      d. other methods and calculations approved by the Department, including appropriate vendor-provided emissions factors when sufficient documentation is provided.

5. **Assessable Emission Estimates.** The Permittee shall comply as follows:

   5.1 No later than March 31 of each year, the Permittee may submit an estimate of the stationary source's assessable emissions as determined in Condition 4.2. Submit actual emissions estimates in accordance with the submission instructions on the Department's Standard Permit Conditions web page at http://dec.alaska.gov/air/air-permit/standard-conditions/standard-condition-i-submission-instructions/.

   5.2 The Permittee shall include with the assessable emissions report all of the assumptions and calculations used to estimate the assessable emissions in sufficient detail so the Department can verify the estimates.

   5.3 If the stationary source has not commenced construction or operation on or before March 31st, the Permittee may submit to the Department's Anchorage office a waiver letter certified under 18 AAC 50.205 that states the stationary source's

[3] If the stationary source has not commenced construction or operation on or before March 31st, submit a transmittal letter certified under 18 AAC 50.205, in accordance with Condition 5.1, that identifies the source's assessable emissions for the previous fiscal year to be zero tons per year and provide estimates for when construction and operation will commence.

actual annual emissions for the previous calendar year are zero TPY and provides estimates for when construction or operation will commence.

5.4 If no estimate or waiver letter is submitted on or before March 31 of each year, emission fees for the next fiscal year will be based on the potential to emit in Condition 4.1.

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Section 3 State Emission Standards

6. **Industrial Process and Fuel-Burning Equipment Visible Emissions.** The Permittee shall not cause or allow visible emissions, excluding water vapor, emitted from industrial processes and fuel burning EUs listed in Table 1 to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.

   6.1 For EUs 11 through 13, 22, 23, 44a, 48a through 59a, 65, and 66; record the date of initial startup[4] of each EU.

   6.2 For liquid fuel-fired EUs 65 and 66, perform an initial Method 9 observation within 60 days of initial startup of each EU:

      a. Report the results of the Method 9 observations required by Condition 6.2 in the first operating report due after the observations were performed, as required under Condition 51.

   6.3 The Permittee shall use only gas as fuel in EUs 12, 13, 44a, and 48a through 59a. The Permittee shall certify in each operating report required under Condition 51 that these EUs burned only gas.

7. **Visible Emissions Monitoring.** The Permittee shall observe the exhaust of EUs 35 and 36 for visible emissions using Method 9 Plan described under Condition 7.1.

   7.1 *Method 9 Plan:* For all 18-minute observations in this plan, observe exhaust, following 40 C.F.R. 60, Appendix A-4, Method 9, Adopted by Reference in 18 AAC 50.040(a), for 18 minutes to obtain 72 consecutive 15-second opacity observations.

      a. First Method 9 Observation: Observe exhaust for 18 minutes within 90 days after initial startup. For any EUs replaced, observe exhaust for 18 minutes within 30 days of startup.

      b. Monthly Method 9 Observations: After the first Method 9 observation, perform 18-minute observations at least once in each calendar month that an EU operates.

      c. Semiannual Method 9 Observation: After observing emissions for three consecutive operating months under Condition 7.1b, unless a six-minute average exceeds 15 percent and one or more observations exceed 20 percent, perform 18-minute observations at least semiannually:

         (i) Within six months after the preceding observation; or

         (ii) For an emission unit with intermittent operations, within 30 days after the next scheduled operation immediately following six months after the preceding observation.

[4] Startup is defined as the period that begins when fuel is supplied to the unit and ends when the unit reaches stable operations.

d. Annual Method 9 Observations: After at least two semiannual 18-minute observations, unless a six-minute average exceeds 15 percent and one or more observations exceed 20 percent, perform 18-minute observations:

(i) Within 12 months after the preceding observation; or

(ii) For an emission unit with intermittent operations, within 30 days after the next scheduled operation immediately following 12 months after the preceding observation.

e. Increased Method 9 Frequency: If a six-minute average opacity observed during the most recent set of observations exceeds 15 percent and one or more observations exceeds 20 percent, then increase or maintain the 18-minute observation frequency for that EU to at least monthly, until the criteria in Condition 7.1c for semiannual monitoring are met.

8. **Visible Emissions Recordkeeping.** The Permittee shall keep records as follows:

8.1 For all Method 9 observations,

a. The observer shall record the following:

(i) the name of the stationary source, EU and location, EU type, observer's name and affiliation, and the date on the VE Emissions Field Data Sheet in Attachment 1;

(ii) the time, estimated distance to the emissions location, sun location, approximate wind direction, estimated wind speed, description of the sky condition (presence and color of clouds), plume background, and operating rate (load or fuel consumption rate) on the sheet at the time opacity observations are initiated and completed;

(iii) the presence or absence of an attached or detached plume and the approximate distance from the emissions outlet to the point in the plume at which the observations are made;

(iv) opacity observations to the nearest five percent at 15-second intervals on the VE Observations Record in Attachment 1; and

(v) the minimum number of observations required by the permit; each momentary observation recorded shall be deemed to present the average opacity of emissions for a 15-second period.

b. To determine the six-minute average opacity, divide the observations recorded on the record sheet into sets of 24 consecutive observations; sets need not be consecutive in time and in no case shall two sets overlap; for each set of 24 observations, calculate the average by summing the opacity of the 24 observations and dividing this sum by 24; record the average opacity on the sheet.

c. Calculate and record the highest 18 consecutive minute average observed.

9. **Visible Emissions Reporting.** The Permittee shall report VE as follows:

   9.1 In each stationary source operating report required under Condition 51, include for the period covered by the report:

      a. Copies of the observation results (i.e. opacity observations) for the EUs, except for the observations the Permittee has already submitted to the Department; and

      b. A summary to include:

         (i) Number of days observations were made;

         (ii) Highest six-minute average observed; and

         (iii) Dates when one or more observed six-minute averages exceeded 20 percent.

      c. A summary of any monitoring or recordkeeping required under Condition 7 and Condition 8 that was not done.

   9.2 Report under Condition 50:

      a. The results of Method 9 observations that exceed an average of 20 percent opacity for any six-minute period;

      b. Any monitoring under Condition 7 that was not performed when required; and

      c. If any fuel other than gas is burned in EUs 12, 13, 44a, and 48a through 59a.

Flares

10. **Visible Emissions MR&R.** For EUs 11, 22, and 23, perform an initial Method 9 observation during the initial daylight flare event.[5] If no event exceeds one hour then the Permittee shall observe the next daylight flare event.

   10.1 Monitor the flare for visible emissions for 18 minutes during flare events using Method 9.

   10.2 Record the following information for observed events:

      a. the flare(s) EU number;

      b. results of the Method 9 observations;

      c. reason(s) for flaring;

      d. date, beginning and ending time of event; and

      e. volume of fuel gas and produced gas flared.

[5] For purposes of this permit, a *"flare event"* is flaring of gas during daylight for greater than one hour as a result of scheduled release operations, i.e. maintenance. It does not include non-scheduled release operations, i.e. process upsets, emergency flaring, or de-minimis venting of gas incidental to normal operations.

10.3 Monitoring of a flare event may be postponed for safety or weather reasons, or because a qualified observer is not available. If monitoring of a flare event is postponed for any of the reasons described in this condition, the Permittee shall include in the next operating report required by Condition 51 an explanation of the reason the event was not monitored.

10.4 Attach copies of the records required by Condition 10.2 in the first operating report due after the observations were performed, as required under Condition 51.

11. **Industrial Process and Fuel-Burning Equipment Particulate Matter (PM).** The Permittee shall not cause or allow particulate matter emitted from industrial process and fuel burning EUs listed in Table 1 to exceed 0.05 grains per dry standard cubic foot of exhaust gas corrected to standard conditions and averaged over three hours, under 18 AAC 50.055(b).

12. **Sulfur Compound Emissions.** The Permittee shall not cause or allow sulfur compound emissions, expressed as sulfur dioxide SO_2, from industrial process and fuel burning EUs listed in Table 1 to exceed 500 parts per million by volume (ppmv) averaged over a three hour period, under 18 AAC 50.055(c).

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Section 4 Ambient Air Quality Protection Requirements

General Requirements

13. The Permittee shall operate the stationary source as described below:

Stack Configuration

13.1 Construct and maintain vertical, uncapped stacks for all EUs listed in Table 1 with stacks, except as noted below:

a. EUs 13, 41, 41B, 41C, 47C, 47D, 60, 61, 65, and 66 may have capped or horizontal releases; and

b. This condition does not preclude the use of flapper valve rain covers, or other similar designs, that do not hinder the vertical momentum of the exhaust plume.

13.2 Confirm in the first operating report required under Condition 51 that would be due after the installation of each EU that the exhaust stack for that EU listed in Table 1 complies with Condition 13.1 and Condition 13.3.

Stack Heights

13.3 Construct and maintain the stacks for the EUs listed in Table 2 with release points above grade that equal or exceed the height indicated in Table 2, to protect the AAAQS and Class II increments associated with the given EU.

Table 2 – Required Stack Heights

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	H_2 Vent Stack	CO, NH_3	80
35 - 36	Granulator Scrubber Exhaust Vents Stack	PM-10, PM-2.5, NH_3	140
44a, 48a, 49a	Package Boilers	NOx, CO, PM-10, PM-2.5	100
50 - 54	Waste Heat Boilers	NOx, CO, PM-10, PM-2.5	100
55a – 59a	Solar Turbine Bypass Stack	NOx, CO, PM-10, PM-2.5	60

13.4 Provide as-built drawings and photographs of the stack for each EU listed in Table 2 no later than the second operating report required under Condition 51 that would be due after installation of the stack.

13.5 Comply with the BACT limits in Section 5, in order to protect the NO_2, PM-10, PM-2.5, and CO Alaska Ambient Air Quality Standards (AAAQS) and Class II increments (as applicable).

Limits to Protect Short-term AAAQS and Class II increments

14. To protect the 24-hour PM-10 AAAQS and increment, and the 24-hour PM-2.5 AAAQS

and increment, the Permittee shall limit the operation of the Gasoline Fired Firewater Pump (EU 66) to no more than four hours per day. Monitor, record, and report as follows:

14.1 Monitor and record EU 66's operating hours each day the unit operates. If EU 66 operates more than four hours per calendar day, report as excess emissions and permit deviation as described in Condition 50.

15. To protect the 1-hour NO_2 AAAQS, the 1-hour and 8-hour CO AAAQS, the 24-hour PM-10 AAAQS and increment, and the 24-hour PM-2.5 AAAQS and increment, the Permittee shall not operate more than one Solar Combustion Turbine (EU 55a – 59a) in bypass mode at a time. Monitor, record, and report as follows:

15.1 Monitor and record the start and end time (including date) each EU 55a through 59a operate in bypass mode. If more than one of EUs 55a through 59a operate in bypass mode at a time, report as excess emissions and permit deviation as described in Condition 50.

16. To protect the 1-hour NO_2 AAAQS, the Permittee shall limit the annual operation of the EUs listed below as follows:

16.1 Startup Heater (EU 13): do not operate for more than 200 hours per year;

16.2 Diesel Fired Well Pump (EU 65): do not operate for more than 168 hours per year;

16.3 Gasoline Fired Firewater Pump (EU 66): do not operate more than 168 hours per year; and

16.4 Monitor and record the hours of operation of EUs 13, 65, and 66 as described in Conditions 21 and 23. If the operating hours for EUs 13, 65, or 66 exceed the limits in Condition 16, report as excess emissions and permit deviation as described in Condition 50.

Limits to Protect Annual AAAQS and Class II increments

17. To protect the annual NO_2 AAAQS, the annual NO_2 increment, the annual PM-10 increment, the annual PM-2.5 AAAQS and the annual PM-2.5 increment, the Permittee shall limit the annual operation of the EUs listed below as follows:

17.1 Solar Combustion Turbines (EUs 55a – 59a): the total operation in bypass mode shall not exceed 204 hours per year, per unit;

17.2 Startup Heater (EU 13): do not operate for more than 200 hours per year;

17.3 Diesel Fired Well Pump (EU 65): do not operate for more than 168 hours per year;

17.4 Gasoline Fired Firewater Pump (EU 66): do not operate for more than 168 hours per year; and

17.5 Monitor and record the hours of operation of EUs 13, 55a through 59a, 65, and 66 as described in Conditions 18, 21, and 23. If the operating hours for EUs 13, 55a through 59a, 65, or 66 exceed the limits in Condition 17, report as excess emissions and permit deviation as described by Condition 50.

Section 5 Best Available Control Technology

BACT Limits

18. **Turbine Emission Limits:** The Permittee shall limit the emissions from the cogeneration turbines EUs 55a through 59a (including corresponding waste heat boilers EUs 50 through 54) as specified in Table 3, except during the allowable hours as specified in Condition 18.1:

Table 3 – Cogeneration Turbine BACT Limits for NOx, CO, PM, VOC, and GHGs

EU ID	Pollutant	BACT Limit	Control Method
55a - 59a & 50 - 54	NOx	5 ppm_{vd} at 15 % O_2 (3-hr average)	Selective Catalytic Reduction and SoLoNOx Technology on Turbines
	CO	50 ppm_{vd} at 15 % O_2 (3-hr average)	Good Combustion Practices
	VOC	0.0036 lb/MMBtu (3-hr average)	Good Combustion Practices
	PM/PM-10/PM-2.5	0.0075 lb/MMBtu (3-hr average)	Good Combustion Practices
	CO_2e	58.4 tons/MMscf (3-hr average) 162,600 tpy combined	Good Combustion Practices Waste Heat Recovery

18.1 Limit the number of hours EUs 55a through 59a operate without waste heat boilers (bypassing the selective catalytic reduction control system) to no more than 204 hours per 12 consecutive month period, each. Monitor, record, and report as described below:

a. Calculate and record monthly, the number of hours each of EUs 55a through 59a operated without a waste heat boiler, for the previous month.

b. Calculate and record monthly, the number of hours each of EUs 55a through 59a operated without a waste heat boiler for the previous 12 consecutive month period.

c. Report in the operating report required in Condition 51 for each month covered in the operating report, the total hours each of EUs 55a through 59a operated without a waste heat boiler as recorded in Condition 18.1b.

18.2 Install, operate, and maintain SoLoNOx control technology on EUs 55a through 59a, according to the manufacturer's specification, at all times the units are operating.

18.3 Install, operate, and maintain selective catalytic reduction (SCR) on EUs 50 through 59a, according to the manufacture's specifications, at all times the units are

operating, except during the allowable hours as specified in Condition 18.1. For each SCR system, install and operate the SCR units as follows:

a. Conduct an initial source test in accordance with Section 9, on at least two of EUs 50 through 59a within 180 days from the first of EUs 50 through 59a beginning operation.

b. Conduct the source test at the maximum achievable load of the EU while the exhaust from the turbine is routed through the waste heat boiler and then through the SCR system (representative of the normal operation scenario).

c. Limit emissions of ammonia slip downstream of the SCR to no greater than 10 ppmv as measured at maximum achievable load in accordance with Condition 18.3d.

d. During the source test required by Condition 18.3a, measure the ammonia slip using the U.S. EPA Method 320 or ASTM D6348 for Fourier Transform Infrared Spectroscopy (FTIR), CTM-027, or Bay Area Source Test Procedure ST-1B, as applicable. The test shall be completed at maximum achievable load. The highest ammonia injection rate setting (gallons per hour) of the three runs shall become the maximum ammonia injection rate for the SCR equipped turbines.

e. Monitor and record the ammonia injection rate in gallons per hour.

f. Prior to startup of EUs 50 through 59a, the Permittee shall identify parameters and practices that constitute proper SoLoNOx and SCR operation and maintenance to comply with the emission limitation conditions of this permit. The Permittee shall include these operational and maintenance parameters and practices in the KNO O&M list of procedures. As a minimum, these shall include manufacturers' operating instructions, normal operating parameters, and preventive maintenance procedures. The Permittee shall keep the operational and maintenance parameters and practices within KNO's O&M procedural library up to date to the extent that they relate to EUs 50 through 59a. The Permittee shall keep the O&M procedures readily available for review by the Department upon request.

g. Report the results of the source test to the Department in accordance with Condition 69, including the information from Condition 18.3d.

18.4 To show compliance with the NOx, emission limits set out in Table 3, the Permittee shall:

a. Conduct an initial source test in accordance with Section 9, on at least two[6] of EUs 50 through 59a within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after initial startup of the turbine.

[6] 40 C.F.R. 60 Subpart KKKK requires initial and annual NOx performance testing on each turbine subject to the new source performance standards of Subpart KKKK unless a waiver is granted by EPA.

b. Conduct the source test for at least two loads representative of the normal operating range of the EU while the exhaust from the turbine is routed through the waste heat boiler and then through the SCR system (representative of the normal operation scenario). One load must be within plus or minus 25 percent of 100 percent of peak load. The Permittee may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice.

c. Use the applicable test method set out in 40 C.F.R. 60, Appendix A. Source test downstream of the selective catalytic reduction control system.

d. Each source test shall consist of at least three 20-minute or longer valid test runs at each load. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of lb/MMBtu as well as the appropriate units for the corresponding pollutant listed in Table 3.

e. During each test run, measure the inlet air temperature and pressure drop across the SCR system.

f. The Permittee shall report the results of the source test to the Department in accordance with Condition 69.

18.5 To show compliance with the CO emission limit set out in Table 3, the Permittee shall:

a. Conduct an initial source test in accordance with Section 9, on at least two of EUs 50 through 59a within 180 days from the first of EUs 50 through 59a beginning operation.

b. Conduct the source test for at least two loads representative of the normal operating range of the EU while the exhaust from the turbine is routed through the waste heat boiler and then through the SCR system (representative of the normal operation scenario).

c. Use the applicable test method set out in 40 C.F.R. 60, Appendix A. Source test downstream of the SCR system.

d. Each source test shall consist of at least three 20-minute or longer valid test runs at each load. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of lb/MMBtu as well as the appropriate units for the corresponding pollutant listed in Table 3.

e. During each test run, measure the inlet air temperature and pressure drop across the SCR system.

f. The Permittee shall report the results of the source test to the Department in accordance with Condition 69.

18.6 To show compliance with the VOC, PM, PM-10, and PM-2.5 emission limits set out in Table 3, the Permittee shall:

a. Submit to the Department, a certified manufacturer's guarantee demonstrating that EUs 50 through 59a will comply with the emission limits in Table 3 at least 60 days before startup of any of EUs 50 through 59a; or

b. Conduct an initial source test in accordance with Section 9, on at least two of EUs 50 through 59a within 180 days from the first of EUs 50 through 59a beginning operation to demonstrate initial compliance with the VOC, PM, PM-10, and PM-2.5 limits listed in Table 3 as follows:

(i) Conduct the source test for at least two loads representative of the normal operating range of the EU while the exhaust from the turbine is routed through the waste heat boiler and then through the SCR system (representative of the normal operation scenario).

(ii) Use the applicable test method set out in 40 C.F.R. 60, Appendix A. Source test downstream of the selective catalytic reduction control system.

(iii) Each source test shall consist of at least three 20-minute or longer valid test runs at each load. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of lb/MMBtu.

(iv) During each test run, measure the inlet air temperature and pressure drop across the SCR system.

(v) The Permittee shall report the results of the source test to the Department in accordance with Condition 69.

18.7 To show compliance with the GHG emission limit set out in Table 3, the Permittee shall:

a. Maintain good combustion practices at all times the units are in operation;

b. Perform regular maintenance according to the manufacturer's or the operator's maintenance procedures;

c. Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format; and

d. Keep a copy of either the manufacturer's or the operator's maintenance procedures.

18.8 Report as described in Condition 50 if any of:

a. the operating hours of any of EUs 55a through 59a, for the 12 consecutive month period, exceed the limit in Condition 18.1;

b. the emission rates determined by the source tests required by Conditions 18.4 through 18.6 exceed the limits in Table 3; or

c. Conditions 18.1 through 18.7 are not met.

19. **Primary Reformer BACT Limits:** The Permittee shall limit the emissions from EU 12 as specified in Table 4:

Table 4 –Reformer BACT Limits for NOx, CO, PM, VOC, and GHGs

EU ID	Pollutant	BACT Limit	Control Method
12	NOx	17 ppm_{vd} at 3% O_2 (30-day average)	Selective Catalytic Reduction
	CO	0.043 lb/MMBtu (3-hr average)	Good Combustion Practices
	VOC	0.0054 lb/MMBtu (3-hr average)	Good Combustion Practices
	PM/PM-10/PM-2.5	0.0075 lb/MMBtu (3-hr average)	Good Combustion Practices
	CO_2e	60.4 tons/MMscf (3-hr average) 700,000 tons per year	Good Combustion Practices

19.1 The Permittee shall develop a preventative maintenance plan within 180 days of initial startup and submit it to the Department with the first operating report required under Condition 51.

19.2 Install, operate, and maintain selective catalytic reduction (SCR) on EU 12, according to the manufacture's specifications, at all times the unit is in operation. Install and operate the SCR unit as follows:

a. Conduct an initial source test in accordance with Section 9, on EU 12 within 180 days from the EU beginning operation.

b. Conduct the source test at the maximum achievable load of the EU.

c. Limit emissions of ammonia slip downstream of the SCR to no greater than 10 ppmv as measured at maximum achievable load in accordance with Condition 19.2d.

d. During the source test required by Condition 19.2a, measure the ammonia slip using the U.S. EPA Method 320 or ASTM D6348 for Fourier Transform Infrared Spectroscopy (FTIR), CTM-027, or Bay Area Source Test Procedure ST-1B, as applicable. The test shall be completed at maximum achievable load. The highest ammonia injection rate setting (gallons per hour) of the three runs shall become the maximum ammonia injection rate for EU 12.

e. Monitor and record the ammonia injection rate in gallons per hour.

f. Prior to startup of EU 12, the Permittee shall identify parameters and practices that constitute proper SCR operation and maintenance to comply

with the emission limitation conditions of this permit. The Permittee shall include these operational and maintenance parameters and practices in the KNO O&M list of procedures. As a minimum, these shall include manufacturers' operating instructions, normal operating parameters, and preventive maintenance procedures. The Permittee shall keep the operational and maintenance parameters and practices within KNO's O&M procedural library up to date to the extent that they relate to EU 12. The Permittee shall keep the O&M procedures readily available for review by the Department upon request.

g. Report the results of the source test to the Department in accordance with Condition 69, including the information from Condition 19.2d.

19.3 To show compliance with the NOx emission limit set out in Table 4, the Permittee shall:

a. Conduct an initial source test in accordance with Section 9, on EU 12 within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after initial startup of the reformer.

b. Conduct the source test for at least two loads representative of the normal operating range of the EU while the exhaust from the reformer is routed through the SCR system (representative of the normal operation scenario). One load must be within plus or minus 25 percent of 100 percent of peak load. The Permittee may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice.

c. Conduct the source test using Method 7 of 40 C.F.R. 60, Appendix A, and 40 C.F.R. 60.46(b) & (d). Source test downstream of the selective catalytic reduction control system.

d. For Method 7 of 40 C.F.R. 60, Appendix A; Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E of appendix A is used, the sampling time for each run shall be at least one hour and the integrated sampling approach shall be used to determine the O_2 concentration (%O_2) for the emission rate correction factor.

e. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of lb/MMBtu as well as the appropriate units for the corresponding pollutant listed in Table 4.

f. During each test run, measure the inlet air temperature and pressure drop across the SCR system.

g. The Permittee shall report the results of the source test to the Department in accordance with Condition 69. Install, certify, maintain, and operate a NOx continuous emissions monitoring system (CEMS) consisting of a NOx monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NOx emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu).

h. Each NO_X and diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B of 40 C.F.R. 60, except the 7-day calibration drift is based on unit operating days, not calendar days. The relative accuracy test audit (RATA) of the CEMS shall be performed on a ppm or lb/MMBtu basis.

i. As specified in §60.13(e)(2), during each full unit operating hour, both the NOx monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NOx emission rate for the hour.

j. The owner or operator shall develop and keep on-site a quality assurance (QA) plan for the NOx and O_2 CEMS.

19.4 Continuous emission monitoring to identify excess emissions:

a. All CEMS data shall be reduced to hourly averages as specified in 40 C.F.R. 60.13(h).

b. For each unit operating hour in which a valid hourly average, as described in Condition 19.3i, is obtained for both NOx and diluent monitors, the data acquisition and handling system must calculate and record the hourly NOx emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in Appendix A of Part 60.

c. Calculate the hourly average NOx emission rates, in units of the emission standards under §60.44.

d. Use the calculated hourly average emission rates from Condition 19.4c to assess excess emissions on a 30-day average.

e. Each NOx CEMS must meet all applicable quality assurance and data recovery requirements of 40 C.F.R. 60.13.

19.5 Reporting Requirements:

a. For all reports required under §60.7(c), report in accordance with Conditions 34 and 35.

19.6 Excess Emissions of NO_X and Downtime for CEMS:

a. For EU 12:

(i) An excess emission for any unit is when the 30-day rolling average NOx emission rate exceeds the applicable emission limit in Condition

19. For the purposes of this condition, a "30-day rolling average NOx emission rate" is the arithmetic average of all hourly NOx emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated for each operating day as the average of all hourly NOx emissions rates for the preceding 30 unit operating days if a valid NOx emission rate is obtained for at least 75 percent of all operating hours.

(ii) Note: The NOx BACT limit for EU 12, as specified in Table 4, is valid at all times, except during startup and shutdown when the catalyst is below normal operating temperature, including while performing the NO_X performance tests and RATA's required by 40 C.F.R. 60.

(iii) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NOx concentration, CO_2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(iv) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

(v) Note: Condition 19.6a(iv) does not include the BACT limit, it is only referring to the standards under 40 C.F.R. 60 Subpart D.

19.7 Maintain the NOx and oxygen CEMS sampling probe in the exhaust stack of the reformer furnace. Continuously monitor and record the rolling 30-day average NOx concentration in parts per million, dry basis, by volume (ppm_{vd}) and oxygen concentration measurements. Correct each rolling 30-day average NOx concentration to 3 percent O_2.

19.8 In each operating report under Condition 51, the Permittee shall attach:

a. The maximum rolling 30-day average NOx emission concentration corrected to 3 percent O_2 obtained from each CEMS required under Condition 19.3a.

b. The date time, and duration, and rolling 30-day average NOx emission concentration corrected to 3 percent O_2 for any period exceeding the limit in Table 4 or a copy of the excess emission report filed under Condition 19.9.

19.9 If the rolling 30-day average NOx emissions exceed the limit in Table 4, the Permittee shall report as an excess emission under Condition 50.

19.10 To show compliance with the CO emission limit set out in Table 4, the Permittee shall:

a. Conduct an initial source test in accordance with Section 9, within 180 days from beginning operation of EU 12.

b. Conduct the source test for at least two loads representative of the normal operating range of the EU while the exhaust from the reformer is routed through the SCR system (representative of the normal operation scenario).

c. Use the applicable test method set out in 40 C.F.R. 60, Appendix A. Source test downstream of the SCR system.

d. Each source test shall consist of at least three 20-minute or longer valid test runs at each load. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of lb/MMBtu.

e. During each test run, measure the inlet air temperature and pressure drop across the SCR system.

f. The Permittee shall report the results of the source test to the Department in accordance with Condition 69.

19.11 To show compliance with the VOC, PM, PM-10, and PM-2.5 emission limits set out in Table 4, the Permittee shall:

a. Submit to the Department, a certified manufacturer's guarantee demonstrating that EU 12 will comply with the emission limits in Table 4 at least 60 days before startup of the EU; or

b. Conduct an initial source test in accordance with Section 9, within 180 days from beginning operation of EU 12 to demonstrate initial compliance with the VOC, PM, PM-10, and PM-2.5 emission limits listed in Table 4 as follows:

(i) Conduct the source test for at least two loads representative of the normal operating range of the EU while the exhaust from the reformer is routed through the SCR system (representative of the normal operation scenario).

(ii) Use the applicable test method set out in 40 C.F.R. 60, Appendix A. Source test downstream of the SCR system.

(iii) Each source test shall consist of at least three 20-minute or longer valid test runs at each load. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of lb/MMBtu.

(iv) During each test run, measure the inlet air temperature and pressure drop across the SCR system.

(v) The Permittee shall report the results of the source test to the Department in accordance with Condition 69.

19.12 To show compliance with the GHG emission limit set out in Table 4, the Permittee shall:

a. Maintain good combustion practices at all times the unit is in operation;

b. Perform regular maintenance according to the manufacturer's or the operator's maintenance procedures;

c. Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format; and

d. Keep a copy of either the manufacturer's or the operator's maintenance procedures.

19.13 Report as described in Condition 50 if any of:

a. the emission rates determined by the source tests required by Conditions 19.3, 19.10 and 19.11 exceed the limits in Table 4; or

b. Conditions 19.1 through 19.12 are not met.

20. **Package Boilers BACT Limits:** The Permittee shall limit the emissions from EUs 44a, 48a, and 49a as specified in Table 5:

Table 5 – Package Boilers BACT Limits for NOx, CO, PM, VOC, and GHGs

EU ID	Pollutant	BACT Limit	Control Method
44a, 48a, & 49a	NOx	0.01 lb/MMBtu (30-day rolling average)	Selective Catalytic Reduction
	CO	50 ppm_{vd} at 3% O_2 (3-hr average)	Good Combustion Practices
	VOC	0.0054 lb/MMBtu (3-hr average)	Good Combustion Practices
	PM/PM-10/PM-2.5	0.0075 lb/MMBtu) (3-hr average)	Good Combustion Practices
	CO_2e	60.2 tons/MMscf (3-hr average) 376,500 tons per year (combined)	Good Combustion Practices

20.1 The Permittee shall develop a preventative maintenance plan within 180 days of initial startup and submit it to the Department with the first operating report required under Condition 51.

20.2 To show compliance with the NOx emission limit set out in Table 5, the Permittee shall:

a. Install, certify, maintain, and operate a NOx CEMS consisting of a NOx monitor and a diluent gas (O_2 or CO_2) monitor, to determine the hourly NOx emission rate in ppm or lb/MMBtu.

b. Each NO_X and diluent CEMS must be installed and certified according to PS 2 in appendix B of 40 C.F.R. 60, except the 7-day calibration drift is based on unit operating days, not calendar days. The RATA of the CEMS shall be performed on a ppm or lb/MMBtu basis.

c. Conduct an initial source test in accordance with Section 9 on EUs 44a, 48a, and 49a using the CEMS for monitoring NOx under 40 C.F.R. 60.48b within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after initial startup of the boilers.

d. For the initial compliance test, NO_X from the EUs are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NO_X emission standards. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

e. As specified in §60.13(e)(2), during each full unit operating hour, both the NOx monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NOx emission rate for the hour.

f. The owner or operator shall develop and keep on-site a QA plan for the NOx CEMS.

g. The Permittee shall report the results of the source test to the Department in accordance with Condition 69.

20.3 Continuous emission monitoring to identify excess emissions:

a. All CEMS data shall be reduced to hourly averages as specified in 40 C.F.R. 60.13(h).

b. For each unit operating hour in which a valid hourly average, as described in Condition 20.2e, is obtained for both NOx and diluent monitors, the data acquisition and handling system must calculate and record the hourly NOx emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in Appendix A of Part 60.

c. Calculate the hourly average NOx emission rates, in units of the emission standards under §60.44, using ppm.

d. Use the calculated hourly average emission rates from Condition 20.3c to assess excess emissions on a 30-day rolling average.

e. Each NOx CEMS must meet all applicable quality assurance and data recovery requirements of 40 C.F.R. 60.13.

20.4 Reporting Requirements:

a. For all reports required under §60.7(c), report in accordance with Conditions 34 and 35.

20.5 Excess Emissions of NO_X and Downtime for CEMS:

a. For EUs 44a, 48a, and 49a:

(i) An excess emission for any unit is when the 30-day rolling average NO_X emission rate exceeds the applicable emission limit in Condition 20. For the purposes of this condition, a "30-day rolling average NOx emission rate" is the arithmetic average of all hourly NOx emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the two unit operating hours immediately preceding that unit operating hour. A new 30-day average is calculated for each operating hour as the average of all hourly NOx emissions rates for the preceding 3 unit operating hours if a valid NOx emission rate is obtained for at least 75 percent of all operating hours.

NOTE: The NO_X BACT limit for EUs 44a, 48a, and 49a, as specified in Table 5, is valid at all times, including while performing the NO_X performance tests and RATA's required by 40 C.F.R. 60.

(ii) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO_2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(iii) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

Note: Condition 20.5a(iii) does not include the BACT limit, it is only referring to the standards under 40 C.F.R. 60 Subpart Db.

20.6 Maintain the NOx and oxygen CEMS sampling probe in each exhaust stack of the package boilers. Continuously monitor and record the rolling 30-day average NOx

concentration in parts per million, dry basis, by volume (ppm_{vd}) and oxygen concentration measurements. Correct each rolling 30-day average NOx concentration to 3 percent O_2.

20.7 Record the starting and ending times of each startup period for the package boilers. Maintain a log to document date, time, and duration.

20.8 In each operating report under Condition 51, the Permittee shall attach:

a. The maximum rolling 30-day average NOx emission concentration corrected to 3 percent O_2 obtained from each CEMS required under Condition 20.2a.

b. The date, time, and duration of each startup period for the package boilers.

c. The date time, and duration, and rolling 30-day average NOx emission concentration corrected to 3 percent O_2 for any period exceeding the limit in Table 5 or a copy of the excess emission report filed under Condition 20.9.

20.9 If the rolling 30-day average NOx emissions exceed the limit in Table 5, the Permittee shall report as an excess emission under Condition 50.

20.10 To show compliance with the CO, VOC, PM, PM-10, and PM-2.5 emission limits set out in Table 5, the Permittee shall:

a. Submit to the Department, a certified manufacturer's guarantee demonstrating that EUs 44a, 48a, and 49a will comply with the emission limits in Table 5 at least 60 days before startup of any of EUs 44a, 48a, and 49a; or

b. Conduct an initial source test in accordance with Section 9, on at least one of EUs 44a, 48a, and 49a within 180 days from the first of EUs 44a, 48a, and 49a beginning operation to demonstrate initial compliance with the CO, VOC, PM, PM-10, and PM-2.5 limits listed in Table 5 as follows:

(i) Conduct the source test for at least two loads representative of the normal operating range of the EU.

(ii) Use the applicable test method set out in 40 C.F.R. 60, Appendix A.

(iii) Each source test shall consist of at least three 20-minute or longer valid test runs at each load. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of lb/MMBtu.

(iv) The Permittee shall report the results of the source test to the Department in accordance with Condition 69.

20.11 To show compliance with the GHG emission limit set out in Table 5, the Permittee shall:

a. Maintain good combustion practices at all times the units are in operation;

b. Perform regular maintenance according to the manufacturer's or the operator's maintenance procedures;

c. Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format; and

d. Keep a copy of either the manufacturer's or the operator's maintenance procedures.

20.12 Report as described in Condition 50 if any of:

a. the emission rates determined by the source tests required by Conditions 20.2 and 20.10 exceed the limits in Table 5; or

b. Conditions 20.1 through 20.11 are not met.

21. **Startup Heater BACT Limits:** The Permittee shall limit the emissions from EU 13 as specified in Table 6:

Table 6 – Startup Heater BACT Limits for NOx, CO, PM, VOC, and GHGs

EU ID	Pollutant	BACT Limit	Control Method
13	NOx	0.098 lb/MMBtu	Good Combustion Practices and Limited Use
	CO	0.082 lb/MMBtu	Good Combustion Practices and Limited Use
	VOC	0.0054 lb/MMBtu	Good Combustion Practices and Limited Use
	PM/PM-10/PM-2.5	0.0075 lb/MMBtu	Good Combustion Practices and Limited Use
	CO_2e	60.4 tons/MMscf 1,200 tons per year	Good Combustion Practices and Limited Use

21.1 Limit the hours of operation that EU 13 operates to no more than 200 hours per 12 consecutive month period. Monitor, record, and report as described below:

a. Monitor and record the startup and shutdown dates and times that EU 13 operates.

b. By the 15th day of each month, calculate and record:

(i) the hours EU 13 operated for the previous month; and

(ii) the total hours EU 13 operated during the previous 12 consecutive month period.

c. Report in each operating report required by Condition 51, for each month covered in the report, the values determined under Conditions 21.1b(i) and 21.1b(ii).

d. Report as excess emissions as described in Condition 50 whenever the values determined under Condition 21.1b(ii) exceed the limit in Condition 21.1.

21.2 To show compliance with the NOx, CO, VOC, PM, PM-10, PM-2.5, and GHG emission limits set out in Table 6, the Permittee shall:

a. Maintain good combustion practices at all times the unit is in operation;

b. Perform regular maintenance according to the manufacturer's or the operator's maintenance procedures;

c. Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format; and

d. Keep a copy of either the manufacturer's or the operator's maintenance procedures.

21.3 Report as described in Condition 50 if any of:

a. the operating hours of EU 13 during any 12 consecutive month period, exceed the limit in Condition 21.1; or

b. Conditions 21.1 through 21.2 are not met.

22. **Flares BACT Limits:** The Permittee shall limit the emissions from EUs 11, 22, and 23 as specified in Table 7.

Table 7 – Flares BACT Limits for NOx, CO, PM, VOC, and GHGs

EU ID	Pollutant	BACT Limit	Control Method
11, 22, & 23	NOx	0.068 lb/MMBtu SSM venting limited to 168 hours/year (each)	Work Practice Requirements and Limited Use
	CO	0.31 lb/MMBtu SSM venting limited to 168 hours/year (each)	Work Practice Requirements and Limited Use
	VOC	0.66 lb/MMBtu SSM venting limited to 168 hours/year (each)	Work Practice Requirements and Limited Use
	PM/PM-10/PM-2.5	0.0075 lb/MMBtu SSM venting limited to 168 hours/year (each)	Work Practice Requirements and Limited Use
	CO_2e	60.2 tons/MMscf 1,500 tons per year (combined)	Work Practice Requirements and Limited Use

22.1 To show compliance with the work practice BACT limits indicated in Table 7, the Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other maintenance events:

a. 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;

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

c. Flares shall be designed and operated during startups, shutdowns, and other maintenance events, in accordance with the general control device and work practice requirements specified in 40 C.F.R. 60.18(c) and (f).

22.2 Limit the number of hours EUs 11, 22, and 23 vent during startup, shutdown, and maintenance events, to no more than 168 hours per 12 consecutive month period, each.

22.3 Monitor, record, and report as follows:

a. Calculate and record monthly, the number of hours each EU 11, 22, and 23 operated during startups, shutdowns, and other maintenance events for the previous month;

b. Calculate and record monthly, the number of hours each EU 11, 22, and 23 operated during startups, shutdowns, and other maintenance events for the previous 12 consecutive month period;

c. Report in the operating report required in Condition 51, for each month covered in the report, the total hours each EU 11, 22, and 23 operated as recorded in Condition 22.3b;

d. A certification in each operating report that the source complied with the requirements in Conditions 22.1a and 22.1b; and

e. Report as excess emissions as described in Condition 50 whenever the total operating hours of EU 11, 22, or 23 as recorded in Condition 22.3c, exceed the limit in Condition 22.2.

23. **Pump Engines BACT Limits:** The Permittee shall limit the emissions from EUs 65 and 66 as specified in Table 8:

Table 8 – Pump Engines BACT Limits for NOx, CO, PM, VOC, and GHGs

EU ID	Pollutant	BACT Limit	Control Method
65	NOx	4.41 lb/MMBtu	Good Combustion Practices Limited Use
	CO	0.95 lb/MMBtu	Good Combustion Practices Limited Use

	VOC	0.36 lb/MMBtu	Good Combustion Practices Limited Use
	PM/PM-10/PM-2.5	0.31 lb/MMBtu	Good Combustion Practices Limited Use
	CO_2e	164 lb/MMBtu 37.42 tons per year	Good Combustion Practices Limited Use
66	NOx	1.63 lb/MMBtu	Good Combustion Practices Limited Use
	CO	0.99 lb/MMBtu	Good Combustion Practices and Limited Use
	VOC	3.03 lb/MMBtu	Good Combustion Practices and Limited Use
	PM/PM-10/PM-2.5	0.10 lb/MMBtu	Good Combustion Practices and Limited Use
	CO_2e	156 lb/MMBtu 27.5 tons per year	Good Combustion Practices and Limited Use

23.1 Limit the hours of operation for each of EUs 65 and 66 to no more than 168 hours, per 12 consecutive month period.

23.2 Monitor and record the startup and shutdown dates and times that EUs 65 and 66 operate.

23.3 By the 15th day of each month, calculate and record the:

a. hours that each of EUs 65 and 66 operated for the previous month; and

b. the total hours that each of EUs 65 and 66 operated during the previous 12 consecutive month period.

23.4 Report in each operating report required by Condition 51, for each month covered in the report, the values determined under Conditions 23.3a and 23.3b.

23.5 Report as excess emissions as described in Condition 50 whenever a value determined under Condition 23.3b exceeds the limit in Condition 23.1.

24. **CO_2 Vent BACT Limits:** The Permittee shall limit the emissions from EU 14 as specified in Table 9:

Table 9 – CO_2 Vent BACT Limits for VOC and GHGs

EU ID	Pollutant	BACT Limit	Control Method
14	CO	2.9 lb/hour (hourly max)	Good Operational Practices

	VOC	11.4 lb/hour (hourly max)	Good Combustion Practices
	CO_2e	845,486 tons/year	Good Combustion Practices

24.1 Within 180 days from initial startup of EU 14, the Permittee shall demonstrate compliance with the CO_2e limit listed Table 9, using the procedures of 40 C.F.R. Part 98 Subpart G.

24.2 Report in the operating report required in Condition 51 the emission rates determined by the 40 C.F.R. Part 98 Subpart G procedures in Condition 24.1.

24.3 Report as excess emissions and permit deviation as described in Condition 50 if the emission rate determined in Condition 24.2, exceeds the CO_2e limit in Table 9.

25. **H_2 Vent BACT Limits:** The Permittee shall limit the startup, shutdown, and maintenance emissions from EU 19 as specified in Table 10:

Table 10 – H_2 Vent BACT Limit for CO

EU ID	Pollutant	BACT Limit	Control Method
19	CO	15,222 lb/startup	Limited Use

25.1 Limit the hours EU 19 operates to no more than 200 hours per 12 consecutive month period.

25.2 Monitor, record, and report as described below:

a. Calculate, record and report monthly, the number of hours EU 19 operated for the previous month;

b. Calculate and record monthly, the number of hours EU 19 operated for the previous 12 consecutive month period;

c. Report in the operating report required in Condition 51, for each month covered in the report, the total hours EU 19 operated as recorded in Condition 25.2b; and

d. Report as excess emissions as described in Condition 50 whenever the total operating hours of EU 19, as recorded in Condition 25.2c, exceeds the limit in Condition 25.1.

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26. **Urea Granulation BACT Limits:** The Permittee shall limit the emissions from EUs 35 and 36 as specified in Table 11:

Table 11 – Urea Granulation BACT Limits for PM, and VOC

EU ID	Pollutant	BACT Limit	Control Method
35 & 36	VOC	90% Control of Methanol, or Methanol Concentration of < 2ppmvd (whichever is less restrictive)	Wet Scrubber
	PM/PM-10/PM-2.5	0.2 lb/ton of urea produced	Wet Scrubber

26.1 Install, operate, and maintain wet scrubbers on EUs 35 and 36, according to the manufacture's specifications, at all times the process is in operation.

26.2 Within 180 days from initial startup of the first of EUs 35 or 36, the Permittee shall conduct source tests in accordance with Section 9 of this permit to demonstrate initial compliance with the VOC and particulate limits listed in Table 11.

26.3 Conduct the tests on one of EUs 35 or 36 at the maximum achievable load for that unit, representative of the normal operating range of the EUs.

26.4 Report in the operating report required in Condition 51 the worst case emission rates determined in the source tests required by Condition 26.2.

26.5 Report as excess emissions and permit deviation as described in Condition 50 if any of the emission rates determined in the source tests required by Condition 26.2 exceed the limits in Table 11, or if EUs 35 or 36 operate without the use of wet scrubber(s).

27. **UF-85 Storage Tank BACT Limits:** The Permittee shall limit the emissions from EU 41A as specified in Table 12:

Table 12 – UF-85 Tank BACT Limits for VOC

EU ID	Pollutant	BACT Limit	Control Method
41A	VOC	0.00004 lb/hr	Wet Scrubber

27.1 Install, operate, and maintain wet scrubbers on EU 41A, according to the plant's appropriate standard operating procedure, at all times the tank is being filled.

27.2 Compliance with the VOC limit shall be demonstrated by submitting a certificate of compliance with Condition 27.1, with each operating report required under Condition 51.

28. **MDEA Storage Tanks BACT Limits:** The Permittee shall limit the emissions from EUs 41B and 41C as specified in Table 13:

Table 13 – MDEA Tanks BACT Limits for VOC

EU ID	Pollutant	BACT Limit	Control Method
41B & 41C	VOC	0.002 tons per year (combined)	Submerged Fill Design

28.1 Install, operate, and maintain tanks with submerged fill design on EUs 41B and 41C, according to the manufacture's specifications, at all times the tanks are in operation.

28.2 Compliance with the VOC limit shall be demonstrated by submitting a certificate of compliance with Condition 28.1, with each operating report required under Condition 51.

29. **Urea Ship Loading BACT Limits:** The Permittee shall limit the emissions from EU 47 as specified in Table 14:

Table 14 – Ship Loading BACT Limits for PM, PM-10, and PM-2.5

EU ID	Pollutant	BACT Limit	Control Method
47	PM	0.0013 lb/ton of urea	Use of UF-85 (Hardening Agent), Product Coolers on Granulation Urea Process Lines Loading into Partial Enclosure Telescoping Chute
	PM-10	0.0011 lb/ton of urea	
	PM-2.5	0.0004 lb/ton of urea	

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

29.2 Compliance with the PM, PM-10, and PM-2.5 limits shall be demonstrated by submitting a certificate of compliance with Condition 29.1, with each operating report required by Condition 51.

30. **Urea Handling Units BACT Limits:** The Permittee shall limit the emissions from EUs 47C through 47D as specified in Table 15:

Table 15 – Urea Handling BACT Limits for PM, PM-10, and PM-2.5

EU ID	Pollutant	BACT Limit	Control Method
47C & 47D	PM, PM-10, PM-2.5	0.005 grains/dscf (3 stack test average)	Fully Enclosed Conveyors and Fabric Filters

30.1 PM emissions from the urea handling units shall be controlled with fully enclosed conveyors and fabric filters at all times.

30.2 Within 180 days from initial startup of EUs 47C or 47D, the Permittee shall conduct a source test in accordance with Section 9 of this permit to demonstrate initial compliance with the particulate matter limits listed in Table 15.

30.3 Conduct the test on one of EUs 47C or 47D during normal operating conditions for the units.

30.4 Report in the operating report required in Condition 51 the worst case emission rates determined in the source test required by Condition 30.2.

30.5 Report as excess emissions and permit deviation as described in Condition 50 if any of the emission rates determined in the source test required by Condition 30.2 exceed the limit in Table 15, or if EUs 47B through 47D operate without the use of fully enclosed conveyors and fabric filters.

31. **Cooling Tower BACT Limits:** The Permittee shall limit the emissions from EU 40 as specified in Table 16:

Table 16 – Cooling Tower BACT Limits for PM, PM-2.5, and PM-10

EU ID	Pollutant	BACT Limit	Control Method
40	PM, PM-10, PM-2.5	0.002 % Drift	High Efficiency Drift Eliminators

31.1 For EU 40, install, operate, and maintain a high efficiency drift eliminator with a maximum drift of 0.002 percent of circulating water.

31.2 For EU 40, within 60 days of startup, the Permittee shall supply 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.

Section 6 Federal Requirements

32. **NSPS Subpart A Notification.** For any affected facility[7] or existing facility[8] regulated under NSPS requirements in 40 C.F.R. 60, the Permittee shall furnish the Department and EPA written or electronic notification of:

    32.1 the date construction or reconstruction of an affected facility commences postmarked no later than 30 days after such date;

    32.2 the actual date of initial startup of an affected facility postmarked within 15 days after such date;

    32.3 any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies unless that change is specifically exempted under an applicable subpart or in 40 C.F.R.. 60.14(e), postmarked 60 days or as soon as practicable before the change is commenced and shall include:

        a. information describing the precise nature of the change,

        b. present and proposed emission control systems,

        c. productive capacity of the facility before and after the change, and

        d. the expected completion date of the change.

    32.4 any proposed replacement of an existing facility, for which 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, postmarked as soon as practicable, but no less than 60 days before commencement of replacement, and including the following information:

        a. the name and address of owner or operator,

        b. the location of the existing facility,

        c. a brief description of the existing facility and the components that are to be replaced,

        d. a description of the existing and proposed air pollution control equipment,

        e. an estimate of the fixed capital cost of the replacements, and of constructing a comparable entirely new facility,

        f. the estimated life of the existing facility after the replacements, and

[7] *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, effective 7/1/07

[8] *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, effective 7/1/07.

g. discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

33. **NSPS Subpart A Startup, Shutdown, & Malfunction Requirements.** The Permittee shall maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of EUs 12, 44a, and 48a through 59a, any malfunctions of the air-pollution control equipment, or any periods during which a continuous monitoring system or monitoring device for EUs 12, 44a, and 48a through 59a is inoperative.

34. **NSPS Subpart A Excess Emissions and Monitoring Systems Performance Report.** Except as provided in Condition 19, the Permittee shall submit to the Department and to EPA a written "excess emissions and monitoring systems performance report" (EEMSP)[9] any time a limit in Condition 19 has been exceeded as described in this condition. Submit the EEMSP reports with the summary reports to EPA semi-annually postmarked by the 30th day following the end of each six month period ending June 30th and December 31st. Written reports of excess emissions shall include the following information:

    34.1 The magnitude of excess emissions computed in accordance with Condition 40.3, any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the process operating time during the reporting period.

    34.2 Identification of each period of excess emissions that occurred during startup, shutdown, and malfunction of EU 12; the nature and cause of any malfunction, and the corrective action taken or preventative measures adopted.

    34.3 The date and time identifying each period during which a Continuous Monitoring System (CMS) was inoperative except for zero and span checks and the nature of any repairs or adjustments.

    34.4 A statement indicating whether or not any excess emissions occurred or the CMS was inoperative, repaired, or adjusted, at any time during the reporting period.

35. **NSPS Subpart A Summary Report Form.** The Permittee shall submit to the Department and to EPA one "summary report form" in the format shown in Figure 1 of 40 C.F.R. 60.7 the NO_X continuous monitoring systems required by Conditions 19 and 20. The report shall be submitted semiannually, postmarked by the 30th day following the end of each 6-month period ending June 30th and December 31st:

    35.1 If the total duration of excess emissions for the reporting period is less than one percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than five percent of the total operating time for the reporting period, submit a summary report form **instead of** the EEMSP report described in Condition 34 is requested, otherwise

    35.2 Submit a summary report form **and the EEMSP** described in Condition 34.

[9] The federal EEMSP report is not the same as the State excess emission report required by Condition 51.

36. **NSPS Subpart A Performance (Source) Tests.** The Permittee shall conduct initial source tests according to Section 9 and as indicated in this condition on any affected facility within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after initial startup, and at such other times as may be required by EPA, and shall provide the Department and EPA with a written report of the results of the source test. The Permittee shall:

    36.1 Conduct source tests and reduce data as set out in 40 C.F.R. 60.8(b), and provide the Department copies of any EPA waivers or approvals of alternative methods.

    36.2 Conduct source tests under conditions specified by EPA to be based on representative performance of EUs 44a, 48a, and 49a.

    36.3 Notify the Department and EPA at least 30 days in advance of the source test.

    36.4 Provide adequate sampling ports, safe sampling platforms, safe access to sampling platforms, and utilities for sampling and testing equipment.

37. **NSPS Subpart A Good Air Pollution Control Practice.** At all times, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate EUs 12, 44a, 48a, and 48a through 59a including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. The Administrator will determine whether acceptable operating and maintenance procedures are being used based on information available, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance records, and inspections of EUs 12, 44a, 48a, and 48a through 59a.

38. **NSPS Subpart A Credible Evidence.** For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of the standards set forth in 40 C.F.R. 60 Subparts D, Db, and KKKK nothing in 40 C.F.R. 60 shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether EUs 12, 44a, and 48a through 59a would have been in compliance with applicable requirements of 40 C.F.R. 60 if the appropriate performance or compliance test or procedure had been performed.

39. **NSPS Subpart A Concealment of Emissions.** The Permittee shall not build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of a standard set forth in 40 C.F.R. 60. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard that is based on the concentration of a pollutant in the gases discharged to the atmosphere.

40. **NSPS Subpart A, Monitoring.** For a Continuous Monitoring System (CMS) required under Condition 19 and 20, the Permittee shall:

    40.1 Install and operate the CMS prior to a performance test conducted under Condition 36, including completion of manufacturer's written requirements or recommendations for installation, operation, and calibration of device.

    40.2 Check the zero (or low level value between zero and 20 percent of span value) and

span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with 40 C.F.R. 60.13(d).

40.3 Reduce data in accordance with Conditions 19 and 20.

Steam Generator Subject to NSPS Subpart D

41. **NSPS Subpart D Standards for Nitrogen Oxides.** For EU 12, the Permittee shall not allow any gases discharged into the atmosphere which contain nitrogen oxides, expressed as NO_2, in excess of 0.20 lb/MMBtu.

a. The Permittee shall perform a NOx source test, in accordance with Section 9, within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after initial startup of the EU to demonstrate compliance with the standard in Condition 41. Compliance shall be determined using the procedures contained in 40 C.F.R. 60.46(b) & (d).

41.2 Notify the Department per Condition 50, should any source test reveal an exceedance of the NOx emissions limit in Condition 41.

Steam Generating Units Subject to NSPS Subpart Db

42. **NSPS Subpart Db Standards for Nitrogen Oxides.** For EUs 44a, 48a, and 49a, the Permittee shall not allow any gases discharged into the atmosphere which: contain nitrogen oxides, expressed as NO_2, in excess of 0.20 lb/MMBtu.

42.1 The Permittee shall perform a NOx source test, in accordance with Section 9, within 60 days after achieving the maximum production rate at which the units will be operated, but not later than 180 days after initial startup of the EUs to demonstrate compliance with the standard in Condition 42. Compliance shall be determined using the procedures contained in 40 C.F.R. 60.46b.

42.2 Notify the Department per Condition 50, should any source test reveal an exceedance of the NOx emissions limit in Condition 42.

Stationary Combustion Turbines Subject to NSPS Subpart KKKK

43. **NSPS Subpart KKKK Standards for Nitrogen Oxides.** For EUs 55a through 59a (including corresponding waste heat boilers EUs 50 through 54), the Permittee shall meet the NOx emission limit of 25 ppmv at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MWh).

43.1 The Permittee shall perform a NOx source test, in accordance with Section 9 and 40 C.F.R. 60.4400, within 60 days after achieving the maximum production rate at which the units will be operated, but not later than 180 days after initial startup of the EUs to demonstrate compliance with the standard in Condition 43.

43.2 Notify the Department per Condition 50, should any source test reveal an exceedance of the NOx emissions limit in Condition 43.

44. **NESHAP Subpart FFFF.** The Permittee shall comply on a timely basis with any applicable requirements of the Miscellaneous Organic Chemical Manufacturing NESHAP, 40 C.F.R. 63 and Subpart FFFF, amended on December 22, 2008.

45. **NESHAP Subpart ZZZZ.** For stationary compression ignition reciprocating internal combustion engines (RICE), comply with the requirements of 40 C.F.R. 63.6590(c).

Section 7 General Recordkeeping and Reporting Requirements

46. **Recordkeeping Requirements.** The Permittee shall keep all records required by this permit for at least five-years after the date of collection, including:

    46.1 copies of all reports and certifications submitted pursuant to this section of the permit; and

    46.2 records of all monitoring required by this permit, and information about the monitoring including:

        a. the date, place, and time of sampling measurements;

        b. the date(s) analyses were performed;

        c. the company or entity that performed the analyses;

        d. the analytical techniques or methods used;

        e. the results of such analyses; and

        f. the operating conditions as existing at the time of sampling or measurement.

47. **Certification.** The Permittee shall certify any permit application, report, affirmation, or compliance certification submitted to the Department and required under the permit by including the signature of a responsible official for the permitted stationary source following the statement: "*Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.*" Excess emissions reports must be certified either upon submittal or with an operating report required for the same reporting period. All other reports and other documents must be certified upon submittal.

    47.1 The Department may accept an electronic signature on an electronic application or other electronic record required by the Department if the person providing the electronic signature:

        a. uses a security procedure, as defined in AS 09.80.190, that the Department has approved; and

        b. accepts or agrees to be bound by an electronic record executed or adopted with that signature.

48. **Submittals.** Unless otherwise directed by the Department or this permit, the Permittee shall submit to the Department one certified copy of reports, compliance certifications, and/or other submittals required by this permit. The Permittee may submit the documents electronically or by hard copy.

    48.1 Submit the certified copy of reports, compliance certifications, and/or other submittals in accordance with the submission instructions on the Department's Standard Permit Conditions web page at http://dec.alaska.gov/air/air-permit/standard-conditions/standard-condition-xvii-submission-instructions/.

49. **Information Requests.** The Permittee shall furnish to the Department, within a reasonable time, any information the Department requests in writing to determine whether cause exists to modify, revoke, reissue, or terminate the permit or to determine compliance with the permit. Upon request, the Permittee shall furnish to the Department copies of records required to be kept by the permit. The Department may require the Permittee to furnish copies of those records directly to the Federal Administrator.

50. **Excess Emissions and Permit Deviation Reports.** The Permittee shall report excess emissions and permit deviations as follows:

    50.1 **Excess Emissions Reporting.** Except as provided in Condition 54, the Permittee shall report all emissions or operations that exceed emissions standards or limits of this permit as follows:

    a. In accordance with 18 AAC 50.240(c), as soon as possible, report

    (i) excess emissions that present a potential threat to human health or safety; and

    (ii) excess emissions that the Permittee believes to be unavoidable.

    b. In accordance with 18 AAC 50.235(a), within two working days after the event commenced or was discovered, report an unavoidable emergency, malfunction, or nonroutine repair that causes emissions in excess of a technology-based emission standard.

    c. If a continuous or recurring excess emissions is not corrected within 48 hours of discovery, report within 72 hours of discovery unless the Department provides written permission to report under Condition 50.1d.

    d. Report all other excess emissions not described in Conditions 50.1a, 50.1b, and 50.1c within 30 days after the end of the month during which the excess emissions occurred or as part of the next routine operating report in Condition 51 for excess emissions that occurred during the period covered by the report, whichever is sooner.

    e. If requested by the Department, the Permittee shall provide a more detailed written report to follow up on an excess emissions report.

    50.2 **Permit Deviations Reporting.** For permit deviations that are not "excess emissions," as defined under 18 AAC 50.990:

    a. Report all other permit deviations within 30 days after the end of the month during which the deviation occurred or as part of the next routine operating report in Condition 51 for permit deviations that occurred during the period covered by the report, whichever is sooner.

    50.3 **Notification Form.** When reporting either excess emissions or permit deviations, the Permittee shall report using either the Department's online form, which can be found at the Division of Air Quality's Air Online Services (AOS) system webpage http://dec.alaska.gov/applications/air/airtoolsweb using the Permittee Portal option,

or, if the Permittee prefers, the form contained in Attachment 2 of this permit. The Permittee must provide all information called for by the form that is used. Submit the report in accordance with the submission instructions on the Department's Standard Permit Conditions webpage found at http://dec.alaska.gov/air/air-permit/standard-conditions/standard-conditions-iii-and-iv-submission-instructions/.

51. **Operating Reports.** The Permittee shall submit to the Department an operating report in accordance with Conditions 47 and 48 by August 1 for the period January 1 to June 30 of the current year and by February 1 for the period July 1 to December 31 of the previous year.

51.1 The operating report must include all information required to be in operating reports by other conditions of this permit, for the period covered by the report.

51.2 When excess emissions or permit deviations that occurred during the reporting period are not included with the operating report under Condition 51.1, the Permittee shall identify

a. the date of the excess emissions or permit deviation;

b. the equipment involved;

c. the permit condition affected;

d. a description of the excess emissions or permit deviation; and

e. any corrective action or preventative measures taken and the date(s) of such actions; or

51.3 When excess emissions or permit deviations have already been reported under Condition 50 during the period covered by the operating report, the Permittee shall either

a. include a copy of those excess emissions or permit deviation reports with the operating report; or

b. cite the date(s) of those reports.

51.4 The operating report must include, for the period covered by the report, a listing of emissions monitored under Conditions 7.1e which trigger additional testing or monitoring, whether or not the emissions monitored exceed an emission standard. The Permittee shall include in the report

a. the date of the emissions;

b. the equipment involved;

c. the permit condition affected; and

d. the monitoring result which triggered the additional monitoring.

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.

53. **Reasonable Precautions to Prevent Fugitive Dust.** A person who causes or permits bulk materials to be handled, transported, or stored, or who engages in an industrial activity or construction project shall take reasonable precautions to prevent particulate matter from being emitted into the ambient air.

    53.1 The Permittee shall keep records of:

        a. complaints received by the Permittee and complaints received by the Department and conveyed to the Permittee; and

        b. any additional precautions that are taken

            (i) to address complaints described in Condition 53.1a or to address the results of Department inspections that found potential problems; and

            (ii) to prevent future dust problems.

    53.2 The Permittee shall report according to Condition 54.3.

54. **Air Pollution Prohibited.** No person may permit 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.

    54.1 **Monitoring.** The Permittee shall monitor as follows:

        a. As soon as practicable after becoming aware of a complaint that is attributable to emissions from the stationary source, the Permittee shall investigate the complaint to identify emissions that the Permittee believes have caused or are causing a violation of Condition 54.

        b. The Permittee shall initiate and complete corrective action necessary to eliminate any violation identified by a complaint or investigation as soon as practicable if

            (i) after an investigation because of a complaint or other reason, the Permittee believes that emissions from the stationary source have caused or are causing a violation of Condition 54; or

            (ii) the Department notifies the Permittee that it has found a violation of Condition 54.

    54.2 **Recordkeeping.** The Permittee shall keep records of

        a. the date, time, and nature of all emissions complaints received;

        b. the name of the person or persons that complained, if known;

c. a summary of any investigation, including reasons the Permittee does or does not believe the emissions have caused a violation of Condition 54; and

d. any corrective actions taken or planned for complaints attributable to emissions from the stationary source.

54.3 **Reporting.** The Permittee shall report as follows:

a. With each stationary source operating report under Condition 51, the Permittee shall include a brief summary report which must include the following for the period covered by the report:

(i) the number of complaints received;

(ii) the number of times the Permittee or the Department found corrective action necessary;

(iii) the number of times action was taken on a complaint within 24 hours; and

(iv) the status of corrective actions the Permittee or Department found necessary that were not taken within 24 hours.

b. The Permittee shall notify the Department of a complaint that is attributable to emissions from the stationary source within 24 hours after receiving the complaint, unless the Permittee has initiated corrective action within 24 hours of receiving the complaint.

c. If emissions present a potential threat to human health or safety, the Permittee shall report any such emissions according to Condition 50.

55. **Emission Inventory Reporting.** The Permittee shall submit to the Department reports of actual emissions for the previous calendar year, by emissions unit, of CO, NH_3, NOx, PM_{10}, $PM_{2.5}$, SO_2, VOCs and Lead (Pb) and lead compounds, as follows:

55.1 **Every-year inventory.** Each year by April 30, if the stationary source's potential to emit for the previous calendar year equals or exceeds:

a. 250 TPY of NH_3, PM_{10}, $PM_{2.5}$, or VOCs; or

b. 2,500 TPY of CO, NOx, or SO_2.

55.2 **Triennial inventory.** Every third year by April 30, if the stationary source's potential to emit (except actual emissions for Pb) for the previous calendar year equals or exceeds:

a. For stationary sources located in Attainment and Unclassifiable Areas:

(i) 0.5 TPY of actual Pb, or

(ii) 1,000 TPY of CO; or

(iii) 100 TPY of SO_2, NH_3, PM_{10}, $PM_{2.5}$, NOx or VOC.

b. For stationary sources located in Nonattainment Areas:

(i) 0.5 TPY of actual Pb, or

(ii) 1,000 TPY of CO or, when located in a CO nonattainment area, 100 TPY of CO; or

(iii) 100 TPY of SO_2, NH_3, PM_{10}, $PM_{2.5}$, NO_x, or VOC; or as specified in Conditions 55.2b(iv) through 55.2b(viii):

(iv) 70 TPY of SO_2, NH_3, $PM_{2.5}$, NOx, or VOC in $PM_{2.5}$ serious nonattainment; or

(v) 70 TPY of PM_{10} in PM_{10} serious nonattainment areas; or

(vi) 50 TPY of NOx or VOC in O_3 serious nonattainment areas; or

(vii) 25 TPY of NOx or VOC in O_3 severe nonattainment areas; or

(viii) 10 TPY of NOx or VOC in O_3 extreme nonattainment areas.

55.3 For reporting under Condition 55.2, the Permittee shall report the annual emissions and the required data elements under Condition 55.4 every third year for the previous calendar year as scheduled by the EPA.[10].

55.4 For each emissions unit and the stationary source, include in the report the required data elements[11] contained within the form included in the Emission Inventory Instructions available at the Department's AOS system on the Point Source Emission Inventory webpage at http://dec.alaska.gov/Applications/Air/airtoolsweb/PointSourceEmissionInventory.

55.5 Submit the report in accordance with the submission instructions on the Department's Standard Permit Conditions webpage at http://dec.alaska.gov/air/air-permit/standard-conditions/standard-conditions-xv-and-xvi-submission-instructions/.

[10] The calendar years for which reports are required are based on the triennial reporting schedule in 40 C.F.R. 51.30(b)(1), which requires states to report emissions data to the EPA for inventory years 2011, 2014, 2017, 2020, and every 3rd year thereafter. Therefore, the Department requires Permittees to report emissions data for the same inventory years by April 30 of the following year (e.g., triennial emission inventory report for 2020 is due April 30, 2021, triennial emission inventory report for 2023 is due April 30, 2024, etc.).

[11] The required data elements to be reported to the EPA are outlined in 40 C.F.R. 51.15 and Tables 2a and 2b to Appendix A of 40 C.F.R. 51 Subpart A.

Section 8 Standard Permit Conditions

56. The Permittee must comply with each permit term and condition. Noncompliance with a permit term or condition constitutes a violation of AS 46.14, 18 AAC 50, and, except for those terms or conditions designated in the permit as not federally enforceable, the Clean Air Act, and is grounds for

    56.1 an enforcement action; or

    56.2 permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280.

57. It is not a defense in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with a permit term or condition.

58. Each permit term and condition is independent of the permit as a whole and remains valid regardless of a challenge to any other part of the permit.

59. The permit may be modified, reopened, revoked and reissued, or terminated for cause. A request by the Permittee for modification, revocation and reissuance, or termination or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

60. The permit does not convey any property rights of any sort, nor any exclusive privilege.

61. The Permittee shall allow the Department or an inspector authorized by the Department, upon presentation of credentials and at reasonable times with the consent of the owner or operator to

    61.1 enter upon the premises where an emissions unit subject to this permit is located or where records required by the permit are kept;

    61.2 have access to and copy any records required by this permit;

    61.3 inspect any stationary source, equipment, practices, or operations regulated by or referenced in the permit; and

    61.4 sample or monitor substances or parameters to assure compliance with the permit or other applicable requirements.

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Section 9 General Source Test Requirements

62. **Requested Source Tests.** In addition to any source testing explicitly required by this permit, the Permittee shall conduct source testing as requested by the Department to determine compliance with applicable permit requirements.

63. **Operating Conditions.** Unless otherwise specified by an applicable requirement or test method, the Permittee shall conduct source testing

    63.1 at a point or points that characterize the actual discharge into the ambient air; and

    63.2 at the maximum rated burning or operating capacity of the emissions unit or another rate determined by the Department to characterize the actual discharge into the ambient air.

64. **Reference Test Methods.** The Permittee shall use the following as reference test methods when conducting source testing for compliance with this permit:

    64.1 Conduct source testing for compliance with requirements adopted by reference in 18 AAC 50.040(a) in accordance with the methods and procedures specified in 40 C.F.R. 60.

    64.2 Conduct source testing for compliance with requirements adopted by reference in 18 AAC 50.040(b) in accordance with the methods and procedures specified in 40 C.F.R. 61.

    64.3 Conduct source testing for compliance with requirements adopted by reference in 18 AAC 50.040(c) in accordance with the methods and procedures specified in 40 C.F.R. 63.

    64.4 Source testing for the reduction in visibility through the exhaust effluent must be conducted in accordance with the procedures set out in 40 C.F.R. 60, Appendix A, Reference Method 9. The Permittee may use the form in Attachment 1 of this permit to record data.

    64.5 Source testing for emissions of total particulate matter, sulfur compounds, nitrogen compounds, carbon monoxide, lead, volatile organic compounds, fluorides, sulfuric acid mist, municipal waste combustor organics, metals and acid gases must be conducted in accordance with the methods and procedures specified in 40 C.F.R. 60, Appendix A.

    64.6 Source testing for emissions of PM-10 and PM-2.5 must be conducted in accordance with the procedures specified in 40 C.F.R. 51, Appendix M, Methods 201 or 201A and 202.

    64.7 Source testing for emissions of any contaminant may be determined using an alternative method approved by the Department in accordance with 40 C.F.R. 63 Appendix A, Method 301.

65. **Excess Air Requirements.** To determine compliance with this permit, standard exhaust gas volumes must only include the volume of gases from the theoretical combustion of

fuel, plus the excess air volume normal for the specific source type, corrected to standard conditions (dry gas at 68°F and an absolute pressure of 760 millimeters of mercury).

66. **Test Deadline Extension.** The Permittee may request an extension to a source test deadline established by the Department. The Permittee may delay a source test beyond the original deadline only if the extension is approved in writing by the Department's appropriate division director or designee.

67. **Test Plans.** Before conducting any source tests, the Permittee shall submit a plan to the Department. The plan must include the methods and procedures to be used for sampling, testing, and quality assurance and must specify how the source will operate during the test and how the Permittee will document that operation. The Permittee shall submit a complete plan no later than 60 days after receiving a request under Condition 62 and at least 30 days before the scheduled date of any test unless the Department agrees in writing to some other time period. Retesting may be done without resubmitting the plan.

68. **Test Notification.** At least 10 days before conducting a source test, the Permittee shall give the Department written notice of the date and time the source test will begin.

69. **Test Reports.** Within 60 days after completing a source test, the Permittee shall submit one certified copy of the results in the format set out in the *Source Test Report Outline*, adopted by reference in 18 AAC 50.030. The Permittee shall certify the results in the manner set out in Condition 47. If requested in writing by the Department, the Permittee must provide preliminary results in a shorter period of time specified by the Department.

70. **Test Exemption.** The Permittee is not required to comply with Conditions 67, 68, and 69 when the exhaust is observed for visible emissions by Method 9 Plan or Smoke/No Smoke Plan.

Section 10 Permit Documentation

Date	*Documentation Details*
May 21, 2019	Department receives original application for AQ0083CPT07
August 8, 2019	Department receives addenda to the application for AQ0083CPT07
August 27/28, 2019	Department receives addenda to the application for AQ0083CPT07
September 13, 2019	Department receives addenda to the application for AQ0083CPT07
January 8, 2020	Department receives addenda to the application for AQ0083CPT07
January 31, 2020	Department receives addenda to the application for AQ0083CPT07
May 19/20, 2020	Department receives technical review response for AQ0083CPT07
November 9, 2020	Department receives addenda to the application for AQ0083CPT07

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Attachment 1 – Visible Emissions Form

VISIBLE EMISSION OBSERVATION FORM

This form is designed to be used in conjunction with EPA Method 9, "Visual Determination of the Opacity of Emissions form Stationary Sources." Temporal changes in emission color, plume water droplet content, background color, sky conditions, observer position, etc. should be noted in the comments section adjacent to each minute of readings. Any information not dealt with elsewhere on the form should be noted under additional information. Following are brief descriptions of the type of information that needs to be entered on the form: for a more detailed discussion of each part of the form, refer to "Instructions for Use of Visible Emission Observation Form." (a copy is available in https://www3.epa.gov/ttnemc01/methods/webinar8.pdf).

- Stationary Source Name: full company name, parent company or division or subsidiary information, if necessary.
- Address: street (not mailing or home office) address of facility where VE observation is being made.
- Phone (Key Contact): number for appropriate contact.
- Stationary Source ID Number: number from NEDS, agency file, etc.
- Process Equipment, Operating Mode: brief description of process equipment (include type of facility) and operating rate, % capacity, and/or mode (*e.g.*, charging, tapping, shutdown).
- Control Equipment, Operating Mode: specify type of control device(s) and % utilization, control efficiency.
- Describe Emission Point: for identification purposes, stack or emission point appearance, location, and geometry; and whether emissions are confined (have a specifically designed outlet) or unconfined (fugitive).
- Height Above Ground Level: stack or emission point height relative to ground level; can use engineering drawings, Abney level, or clinometer.
- Height Relative to Observer: indicate height of emission point relative to the observation point.
- Distance from Observer: distance to emission point; can use rangefinder or map.
- Direction from Observer: direction plume is traveling from observer.
- Describe Emissions and Color: include physical characteristics, plume behavior (*e.g.*, looping, lacy, condensing, fumigating, secondary particle formation, distance plume visible, etc.), and color of emissions (gray, brown, white, red, black, etc.). Note color changes in comments section.
- Visible Water Vapor Present?: check "yes" if visible water vapor is present.
- If Present, is Plume…: check "attached" if water droplet plume forms prior to exiting stack, and "detached" if water droplet plume forms after exiting stack.
- Point in Plume at Which Opacity was Determined: describe physical location in plume where readings were made (*e.g.*, 1 ft above stack exit or 10 ft. after dissipation of water plume).
- Describe Plume Background: object plume is read against, include texture and atmospheric conditions (*e.g.*, hazy).
- Background Color: sky blue, gray-white, new leaf green, etc.
- Sky Conditions: indicate cloud cover by percentage or by description (clear, scattered, broken, overcast).
- Wind Speed: record wind speed; can use Beaufort wind scale or hand-held anemometer to estimate.
- Wind Direction From: direction from which wind is blowing; can use compass to estimate to eight points.
- Ambient Temperature: in degrees Fahrenheit or Celsius.

  Wet Bulb Temperature: can be measured using a sling psychrometer

  RH Percent: relative humidity measured using a sling psychrometer; use local US Weather Bureau measurements only if nearby.
- Source Layout Sketch: include wind direction, sun position, associated stacks, roads, and other landmarks to fully identify location of emission point and observer position.

  Draw North Arrow: to determine, point line of sight in direction of emission point, place compass beside circle, and draw in arrow parallel to compass needle.

  Sun's Location: point line of sight in direction of emission point, move pen upright along sun location line, mark location of sun when pen's shadow crosses the observer's position.
- Observation Date: date observations conducted.
- Start Time, End Time: beginning and end times of observation period (*e.g.*, 1635 or 4:35 p.m.).
- Data Set: percent opacity to nearest 5%; enter from left to right starting in left column. Use a second (third, etc.) form, if readings continue beyond 30 minutes. Use dash (-) for readings not made; explain in adjacent comments section.

  Comments: note changing observation conditions, plume characteristics, and/or reasons for missed readings.

  Range of Opacity: note highest and lowest opacity number.
- Observer's Name: print in full.

  Observer's Signature, Date: sign and date after performing VE observation.
- Organization: observer's employer.

  Certified By, Date: name of "smoke school" certifying observer and date of most recent certification.

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR PERMITS PROGRAM - VISIBLE EMISSIONS OBSERVATION FORM

Page No:

Stationary Source Name | Type of Emission Unit

Emission Unit Location

City | State | Zip

Phone # (Key Contact) | Stationary Source ID Number

Process Equipment | Operating Mode

Control Equipment | Operating Mode

Describe Emission Point/Location

Height above ground level | Height relative to observer | Inclinometer Reading

Distance From Observer (Start, End) | Direction From Observer (Start, End)

Describe Emissions & Color (Start, End)

Visible Water Vapor Present? No Yes — If yes, determine approximate distance from the stack exit to where the plume was read

Point in Plume at Which Opacity Was Determined

Describe Plume Background (Start, End) | Background Color (Start, End)

Sky Conditions: (Start, End)

Wind Speed (Start, End) | Wind Direction From (Start, End)

Ambient Temperature | Wet Bulb Temp | RH percent

SOURCE LAYOUT SKETCH 1 Stack or Point Being Read 2 Wind Direction From 3 Observer Location 4 Sun Location 5 North Arrow 6 Other Stacks

Observation Date | Start Time | End Time

Min \ Sec	0	15	30	45	Comments
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					

Range of Opacity: Minimum | Maximum

I have received a copy of these opacity observations

Print Name:

Signature:

Title | Date

Print Observer's Name

Observer's Signature | Date

Observer's Affiliation:

Certifying Organization

Certified By: | Date

Data Reduction:

Duration of Observation Period (minutes):

Duration Required by Permit (minutes):

Number of Observations:

Highest Six–Minute Average Opacity (%):

Number of Observations exceeding 20%:

In compliance with six-minute opacity limit? (Yes or No)

Highest 18-Consecutive –Minute Average Opacity (%)(engines and turbines only)

Average Opacity Summary:

Set Number	Time			Opacity		
	Start	End		Sum	Average	Comments

Attachment 2 - ADEC Notification Form[12]

Kenai Nitrogen Operations	AQ0083CPT07
Stationary Source Name	**Air Quality Permit**
Agrium U.S. Inc.	
Company Name	**Date**

When did you discover the Excess Emissions/Permit Deviation?

Date: _____/_____/_____ Time: _____:_____

When did the event/deviation occur?

Begin: Date: _____/_____/_____ Time: _____:_____ (please use 24-hr clock)

End: Date: _____/_____/_____ Time: _____:_____ (please use 24-hr clock)

What was the duration of the event/deviation? _____:_____ (hrs:min) or _____days

(total # of hrs, min, or days, if intermittent then include only the duration of the actual emissions/deviation)

Reason for Notification (Please check only 1 box and go to the corresponding section.):

☐ Excess Emissions - Complete Section 1 and Certify

Note: All "excess emissions" are also "permit deviations." However, use only Section 1 for events that involve excess emissions.

☐ Deviation from Permit Conditions - Complete Section 2 and Certify

Note: Use only Section 2 for permit deviations that do not involve excess emissions.

☐ Deviation from COBC[13], CO[14], or Settlement Agreement - Complete Section 2 and Certify

[12] Revised as of November 7, 2020.
[13] Compliance Order By Consent
[14] Compliance Order

Section 1. Excess Emissions

(a) **Was the exceedance** ☐Intermittent or ☐Continuous

(b) **Cause of Event** (Check one that applies. Complete a separate form for each event, as applicable.):

☐Start Up/Shut Down
☐Natural Cause (weather/earthquake/flood)
☐Control Equipment Failure
☐Scheduled Maintenance/Equipment Adjustments
☐Bad fuel/coal/gas
☐Upset Condition
☐Other _____

(c) **Description**

Describe briefly what happened and the cause. Include the parameters/operating conditions exceeded, limits, monitoring data and exceedance. Attach supporting information if necessary.

(d) **Emissions Units (EU) Involved:**

Identify the emissions units involved in the event, using the same identification number and name as in the permit. Identify each emission standard potentially exceeded during the event and the exceedance.

EU ID	EU Name	Permit Condition Exceeded/Limit/Potential Exceedance

(e) **Type of Incident:** (Please check all that apply and provide the value requested, if any):

☐Opacity _____%

☐Control Equipment Down

☐Emission Limit Exceeded

☐Flaring

☐Other: _____

☐Venting _____(gas/scf)

☐Fugitive Emissions

☐Marine Vessel Opacity

(f) **Corrective Actions:**

Describe actions taken to restore the system to normal operation and to minimize or eliminate chances of a recurrence. Attach supporting information if necessary.

(g) **Unavoidable Emissions:**

Do you intend to assert that these excess emissions were unavoidable? ☐YES ☐NO

Do you intend to assert the affirmative defense of 18 AAC 50.235? ☐YES ☐NO

Certify Report (<u>go to end of form</u>)

Section 2. Permit Deviations

(a) **Permit Deviation Type:** (Check all boxes that apply per event. Complete a separate form for each event, as applicable.)

- ☐ Emissions Unit-Specific Requirements
- ☐ Stationary Source-Wide Specific Requirements
- ☐ Monitoring/Recordkeeping/Reporting Requirements
- ☐ General Source Test Requirements
- ☐ Compliance Certification Requirements
- ☐ Standard/Generally Applicable Requirements
- ☐ Insignificant Emissions Unit Requirements
- ☐ Other: _____

(b) **Emissions Units (EU) Involved:**

Identify the emissions units involved in the event, using the same identification number and name as in the permit. List the corresponding permit condition and the deviation.

EU ID	EU Name	Permit Condition /Potential Deviation

(c) **Description of Potential Deviation:**

Describe briefly what happened and the cause. Include the parameters/operating conditions and the potential deviation. Attach supporting information if necessary.

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(d) **Corrective Actions:**

Describe actions taken to correct the deviation or potential deviation and to prevent future recurrence. Attach supporting information if necessary.

Certification:

Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.

Printed Name:_____Title_____Date _____

Signature:_____ Phone number_____

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NOTE: *This document must be certified in accordance with 18 AAC 50.345(j). Read and sign the certification in the bottom of the form above. (See Condition 47.)*

Submit this report in accordance with the submission instructions on the Department's Standard Permit Conditions web page at http://dec.alaska.gov/air/air-permit/standard-conditions/standard-conditions-iii-and-iv-submission-instructions/.

If submitted online, report must be submitted by an authorized E-signer for the stationary source (according to Condition 47).

=

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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

Prepared by Dave Jones
Reviewed by Aaron Simpson

Final – March 26, 2021

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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

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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

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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

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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.

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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

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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.

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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.

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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.

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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.

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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.

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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.

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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).

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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

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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.

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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	-	-	-	-	-	-

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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)

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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

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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

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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

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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

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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

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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

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turbines.

Step 2 - Eliminate Technically Infeasible NOx Control Options for Cogeneration Turbines
As explained in Step 1, SNCR, NSCR, SCONOX™, and XONON™ 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.

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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;

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(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

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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

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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

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(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

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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;

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(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.

(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. The Department considers SCR a feasible control technology for the startup heater.

(c) 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.

(d) 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.

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(e) 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.

(f) 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:

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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;

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(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.

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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:

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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

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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

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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.

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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:

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(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.

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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

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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

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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.

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(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:

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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.

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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.

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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

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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.

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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:

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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.

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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.

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(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.

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(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;

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(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.

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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.

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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		

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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.

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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:

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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

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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.

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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:

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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.

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(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;

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(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.

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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;

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(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.

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(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;

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(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.

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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

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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:

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(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

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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

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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

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(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:

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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).

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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

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(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:

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(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.

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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:

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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.

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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:

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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

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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

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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

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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

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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

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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.

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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

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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.

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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

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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.

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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,

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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

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(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							
Flare Work Practice Requirements and Minimization Plan						11	
Good Operational Practice including CO_2 reuse							11

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Description of GHG BACT	Cogeneration Gas Turbines	Primary Reformer	Package Boilers	Startup Heater	Pump Engines	Flares	CO_2 Vent
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.

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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 400°F. The heat source for this application is the gas turbine exhaust, and is approximately 800 to 1,000 °F, 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 40°F (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.

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(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

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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)

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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)
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.

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

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(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:

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(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

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(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.

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(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

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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

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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:

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(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.

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(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

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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:

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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.

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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;

(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:

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

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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

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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.

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APPENDIX C: MODELING REPORT

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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
Final Date: March 12, 2021

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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 turbines; reducing the heat input of the waste heat boilers, EUs 50 through 54; and the

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

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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]
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*

[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).

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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 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**).

[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

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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 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] 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.

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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.

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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.

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

[6] The sonic anemometer became operational on September 21, 2006.

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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

[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.

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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.

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

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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.

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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 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

[8] *AERMOD Implementation Guide* (EPA-454/B-18-003); April 2018.

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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 Velocity	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

[9] The NOx and SO_2 emissions are also referred as "precursor emissions" in a PM-2.5 assessment.

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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-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.

[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.

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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.

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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	--

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	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.

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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).

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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.

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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 $\mu g/m^3$) is less stringent than the annual PM-2.5 primary NAAQS/AAAQS (12 $\mu g/m^3$). Therefore, a modeling analysis that demonstrates compliance with the AAAQS also demonstrates compliance with the secondary NAAQS.

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 ($\mu g/m^3$)	Secondary NAAQS ($\mu g/m^3$)
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

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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

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Stack Heights

- 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

- 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

- Limit the hours of operation of the Solar Combustion Turbines (EUs 55a through 59a) in bypass mode to no more than 204 hours/year;
- Limit the hours of operation of the Startup Heater (EU 13) to no more than 200 hours/year; and
- 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

- Operate no more than one of the Solar Combustion Turbines (EUs 55a through 59a) concurrently when in bypass mode;
- Limit the hours of operation of the Fire Pump Engine (EU 66) to no more than 4 hours per day;
- Limit the hours of operation of the Startup Heater (EU 13) to no more than 200 hours/year; and
- 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.

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Response to Comments on Preliminary Construction Permit AQ0083CPT07
Agrium, U.S. Inc. – Kenai Nitrogen Operations

Prepared by Jesse R. Jack on March 26, 2021

This document provides the Alaska Department of Environmental Conservation's (Department's) reply to all public comments on the preliminary decision to issue Construction Permit AQ0083CPT07 to Agrium, U.S. Inc. (Agrium), for the Kenai Nitrogen Operations (KNO) in Nikiski, Alaska. The Department provided opportunity for public comment from November 20, 2020 through December 20, 2020. Jay McAlpine of the United States Environmental Protection Agency, Region 10 office (US EPA R10), was the only commenter.

All comments are provided verbatim, unless noted otherwise. The Department's responses are shown in *Times New Roman italic font.*

Commenter: US EPA R10

Suggested language to be included is **bold.** Suggested language to be removed is ~~strikeout.~~

The Commenter submitted comments on December 18, 2020. This document addresses the comments made on the preliminary permit decision.

Modeling Review, Appendix C of Technical Analysis Report for Preliminary Permit AQ0083CPT07

1. The EPA recommends the secondarily formed component of PM2.5 be addressed quantitatively in the air quality impact assessment.

   Section 5.9.2 of the TAR addresses First-Tier and Second-Tier analyses to estimate the impacts of secondarily formed PM2.5 and ozone. Section 5.4.2 of 40 CFR 51, Appendix W (the Guideline on Air Quality Models, "the Guideline") specifies "for situations where a project source emits both primary PM2.5 and PM2.5 precursors, the contribution from both should be combined for use in determining the source's ambient impact." Therefore, a quantitative estimate of a project's secondarily formed air pollutant impacts should be made.

   EPA's May 2014 PM2.5 modeling guidance is outdated because it does not completely align with the 2017 Guideline (40 CFR 51, Appendix W) revisions. The qualitative approach used in the application, though in line with the May 2014 PM2.5 modeling guidance, is not recommended under the 2017 revision of the Guideline because it does not provide a quantitative estimate of the project's secondary PM2.5 impact. The need for quantitative analysis has been recently reinforced in EPA's 2020 draft PM2.5 permit modeling guidance release [link] which provides a set of recommended approaches for PM2.5 and ozone compliance demonstrations under the 2017 PM2.5 modeling guidance revisions.

   The EPA recommends Alaska DEC perform a Tier 1 analysis for this project and future sources in the Cook Inlet region consistent with the secondary pollutant assessment procedures in Sections 5.3 and 5.4 of the Guideline. The EPA's 2019 "MERPs guidance" is a recommended source of information to estimate secondary air pollutant impacts.

Although none of the hypothetical MERPs sources in the 2019 MERPs guidance are located in Alaska, the "Skagit County, WA" hypothetical source could be considered adequately representative of sources along the Pacific coast of Alaska. The Skagit County hypothetical source is located in a marine temperate forest climate, adequately similar to the marine boreal climate of the Cook Inlet. The Skagit County hypothetical source is also the nearest hypothetical source to Alaska and located in a region with similar background sources, such as oil refineries.

Response: The Department conducted a quantitative analysis of the NOx-driven secondary PM-2.5 formation, as requested. Daily and Annual data were obtained from EPA's "MERPs View Qlik" website and, along with the values from Agrium's modeling analysis, input into the equations presented in EPA's 2019 Guidance referenced above. SO_2 was not considered as a precursor as its emissions are below the Significant Emission Rate (SER).

The Department estimated secondary PM-2.5 annual and daily impacts of 1.49 and 2.30 percent, respectively, of the applicable Significant Impact Level (SIL). This fraction of each SIL was added to the corresponding AAAQS and Increment modeled impacts to determine a cumulative primary and secondary estimate for KNO. The results of this analysis, show in Table 1 below, indicate that secondary PM-2.5 impacts will not contribute to a violation of the AAAQS or Increments.

Table 1 – Primary and Secondary PM-2.5 impacts

Cumulative PM-2.5 Impacts (µg/cu.m.)				
	AAAQS		Increments	
	Annual	Daily/24-hour	Annual	Daily/24-hour
Primary	1.12	6.03	1.51	8.39
Secondary	0.00297	0.0276	0.00297	0.0276
Total Impact	**1.12**	**6.06**	**1.51**	**8.42**
Background	3.6	12		
Cumulative Impact	**4.72**	**18.1**		

2. The Agrium Kenai facility is located adjacent to the site of the proposed AGDC Liquefaction Plant facility. Both facilities are currently under review for PSD construction air permits. Based on the information provided, it does not appear the emissions from the AGDC facility were considered in the air quality impact analysis (AQIA). Given a permit has not yet been issued for the facility, it is understood the facility may not be considered for the AQIA under Alaska DEC's permit modeling policies. However, given the significant emissions from the AGDC facility and the results of the Agrium AQIA showing 1-hour NO_2 concentrations near the AAQS threshold and PM2.5 concentrations near the Class II increment thresholds, there is concern potential air quality impacts may not be fully addressed in the AQIAs of both permits.

   Given these concerns, the EPA recommends Alaska DEC take careful precautions to ensure protection of the Alaska AAQS and PSD increments in the region of the projects. Additional modeling analysis may be warranted. Given the uncertainty in the AQIA, ADEC could consider requiring post-construction monitoring, as specified in 40 CFR 52.21(m)(2), of NO_2 and $PM_{2.5}$ (and any other air pollutants of concern) of the latter of the two sources to be permitted. A monitoring condition should ideally require the monitor to be located in the vicinity of where the maximum cumulative ambient impact is expected to occur and should operate for at least one full year after both sources are operating.

<u>Response:</u> The Department notes EPA's recommendation and agrees that necessary precautions to protect the AAAQS and PSD increments are warranted, given the potential for overlapping impacts between Agrium's KNO facility and the proposed AGDC Liquefaction facility nearby.

As EPA pointed out, explicitly modeling the AGDC Liquefaction facility is not required under Alaska's modeling policies as a permit has not been issued for that potential future project. The Department also notes that there are several reasons to believe that it is highly improbable that the Agrium KNO facility and the AGDC Liquefaction facility will operate contemporaneously, as proposed, without further permitting. Although Agrium is renewing their construction permit with the current permitting effort, the facility has been on "standby" status for a number of years and is likely to do so for at least the near future. Although AGDC has applied for and is seeking a construction permit for its Liquefaction facility, actual construction of this project is not likely to commence for several years, which would necessitate a renewal of their construction permit.

In any event, the Department foresees opportunities to evaluate the potential of cumulative impacts from these two sources and determine if the AAAQS or increments are threatened. The Department also has authority to require an investigation under 18 AAC 50.201 should evidence be found that there is a reasonable likelihood of such a violation occurring. Finally, the Department understands EPA's comment that monitoring requirements be imposed for "the latter of the two sources" refers to the AGDC Liquefaction facility, and that no action is proposed in the context of Construction Permit AQ0083CPT07 for Agrium's KNO. Therefore, the Department has not made any changes to this permit.

Message

From: McAlpine, Jerrold [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=E32164D5B4F448AF91AEA4A9E872EF54-MCALPINE, J]
Sent: 9/13/2018 7:02:51 PM
To: Baker, Kirk [Baker.Kirk@epa.gov]
CC: Elleman, Robert [Elleman.Robert@epa.gov]; Kotchenruther, Robert [Kotchenruther.Robert@epa.gov]
Subject: MERPs final guidance Region 10 comments
Attachments: MERPs Guidance Final 2018 sep 13 version-R10comments.docx

Kirk,

Region 10 has reviewed the guidance. I've offered a few comments (embedded in attached document). In summary:

a) Comment 1 on page 14: I am agreeing with Ex. 5 Deliberative Process (DP) Ex. 5 Deliberative Process (DP). I think it is important to Ex. 5 Deliberative Process (DP) Ex. 5 Deliberative Process (DP)

b) Comment 2 on page 26: I am recommending a statement be added recommending Ex. 5 Deliberative Process (DP) Ex. 5 Deliberative Process (DP) Ex. 5 Deliberative Process (DP). I've recommended the Ex. 5 Deliberative Process (DP) Ex. 5 Deliberative Process (DP) Ex. 5 Deliberative Process (DP)

Thank you,
Jay

Jay McAlpine, PhD
Atmospheric Scientist, Regional Modeling Contact
Office of Air and Waste
U.S. Environmental Protection Agency, Region 10
1200 Sixth Avenue, Suite 155, OAW-150
Seattle, WA 98101
206.553.0094
McAlpine.Jay@epa.gov

Message

From: Bart Brashers [bbrashers@ramboll.com]
Sent: 5/28/2020 7:41:44 PM
To: McAlpine, Jerrold [McAlpine.Jay@epa.gov]
Subject: RE: 1-hour NO2 SILs - still 'interim'?

Hi Jay,

Thanks much, this was very helpful.

Bart

From: McAlpine, Jerrold <McAlpine.Jay@epa.gov>
Sent: Thursday, May 28, 2020 12:05 PM
To: Bart Brashers <bbrashers@ramboll.com>
Subject: RE: 1-hour NO2 SILs - still 'interim'?

Well, the word from OAQPS policy folks is the 1-hour SILs should still be considered "interim." The 2010/2011 guidance docs are still the most relevant guidance and the declaration of the SILs as 'interim' in these docs still stands for the time being.

Hope this helped,
Jay

Jay McAlpine, Ph.D.
Atmospheric Scientist, Regional Air Modeling Contact
(206) 553-0094 | mcalpine.jay@epa.gov
Division of Air and Radiation | U.S. EPA, Region 10, Seattle, WA

From: McAlpine, Jerrold
Sent: Thursday, May 28, 2020 10:40 AM
To: 'Bart Brashers' <bbrashers@ramboll.com>
Subject: RE: 1-hour NO2 SILs - still 'interim'?

Good question, I'm not sure. There is a lot of churn in the policy department concerning SILs, since the recent lawsuit concerning the PM2.5/Ozone SILs guidance. Based on what I'm hearing, I believe there are several guidance documents in the works that will clarify the EPA's stance on SILs and emissions for SILs modeling. Given the EPA is now going to consider SILs in guidance only, and not rulemaking, it makes sense to consider the 1-hour SILs as no longer 'interim', since the 2010/2011 guidance docs are all in final form – I pinged George Bridgers to see if he or Tyler Fox can provide some insight … his response was he still believes we should consider the SILs as "interim." However, he is going to ask the policy folks to double check.

I have continued to use and look for the use of the term "interim" in the work I have been involved with – it will be good to know if we should continue doing this.

Jay

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Division of Air and Radiation | U.S. EPA, Region 10, Seattle, WA

From: Bart Brashers <bbrashers@ramboll.com>
Sent: Thursday, May 28, 2020 9:52 AM
To: McAlpine, Jerrold <McAlpine.Jay@epa.gov>
Subject: 1-hour NO2 SILs - still 'interim'?

Hi Jay,

I was trying to use the new www.epa.gov/guidance interface, but could not find what I wanted. Perhaps some people file that interface helpful.

I'm pretty sure I know the answer to this, but I thought I'd check with you anyway. Are the 1-hr NO2 SILs still 'interim', not 'final' guidance?

The 2018 O3/PM2.5 SILs memo refers to the 2010 Page memo, which says it has been augmented by the Mar 1, 2011 memo from Tyler Fox (link in the 2010 memo is broken). But the O3/PM2.5 memo does not cite the 2011 memo.

The 2010 memo also says the SIL is interim until EPA promulgates a 1-hour NO2 SIL via rulemaking, but now know from the PM2.5 SIL rulemaking and subsequent lawsuit that EPA has since taken the position that all SILs are guidance, not rule.

(It's interesting that the recent BOEM promulgation puts those same SILs in a *rule* – but left out the 1-hour NO2 interim SIL. You'd think that would open them up to lawsuits.)

Bart

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Message

From: McAlpine, Jerrold [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=E32164D5B4F448AF91AEA4A9E872EF54-MCALPINE, J]
Sent: 8/1/2019 5:32:24 PM
To: Viswanathan, Krishna [Viswanathan.Krishna@epa.gov]; Bray, Dave [Bray.Dave@epa.gov]
Subject: Kalispel Air Consultation -- Internal overview document
Attachments: Kalispel-Air-Consultation-OverviewDoc.docx

Krishna, Dave:

Attached please find a document I've put together to compile and summarize the issues to be discussed with the Kalispel Tribe regarding the PacWest project air permit involving:

a) The PSD air permit modeling protocol and associated prognostic meteorological modeling and performance analysis, and:
b) The CALPUFF alternative model approval.

I hope this document can work as a template to guide our internal preparations for the Tribal consultation.

Jay

Jay McAlpine, PhD
Meteorologist -- Regional Modeling Contact
206.553.0094
Division of Air and Radiation, Air Permits and Toxics Branch
U.S. Environmental Protection Agency, Region 10, Seattle, WA

Project:	HiTest Smelter PSD Dispersion Modeling Protocol
Attention:	**Ranil Dhammapala, WA Dept. Ecology**
Reviewer:	Jay McAlpine, Regional Modeler, EPA Region 10
Date:	**20 Nov 2017**
Version:	**Draft**

Summary and Actions Recommended:

The Washington State Department of Ecology ("Ecology") asked EPA Region 10 ("Region 10") to review and comment on the HiTest Sand LLC, Newport, WA ("HiTest") PSD modeling protocol ("the protocol") and provide technical assistance as needed with the review of the associated air quality analyses. This document provides a list of our comments and recommendations. This review was conducted in accordance with the 2017 Guideline on Air Quality Models, 40 CFR Part 51, Appendix W ("Appendix W").

#	Section	Topic	Comment
1	1.1.1	Criteria Pollutant Emissions	The annual TPY of emissions are lower than initially estimated based on review of similar facilities. Using ratios based on throughput and emissions reported in the Mississippi Silicon, LLC 2014 air permit application, Region 10 was expecting higher annual emissions based on an initial HiTest estimate of 55,000 tpy Silicon production. It is understood Ecology engineers will conduct a thorough evaluation of emissions. Based on the discussion at the protocol meeting with the applicant, it is inferred some modern engineering developments may result in lower emission rates than estimated for older silicon smelter facilities.
2	2.2.2	Meteorology	The ID41 tower is not an official NWS ASOS station nor PSD-quality onsite tower. It was originally assumed the tower could possibly qualify as an ASOS-equivalent tower and therefore appropriate for PSD, as allowed under Appendix W. It is understood Ecology conducted a review of this station, with the help of the State of Idaho. The review concluded the tower is neither an ASOS-equivalent quality station nor is maintained under a consistent quality assurance program. Based on Ecology's findings, we agree with Ecology's decision that the ID41 meteorological dataset is not appropriate for major New Source Review air permitting.
3	2.2.2	Meteorology alternatives	The protocol does not offer an alternative meteorological dataset or methodology for Class II modeling. Region 10 has confirmed there is no appropriate representative NWS or ASOS-equivalent meteorological monitoring station in the vicinity of the proposed source site. The nearest ASOS station, KDEW, is over 35 km southwest of the site. Due to the complex terrain and known heterogeneous wind climatology in the region, we recommend KDEW not be used for this project. We recommend the following alternatives be considered: I. Use of the University of Washington 3-year 4km WRF or 1.3km dataset to provide AERMOD meteorological inputs via MMIF, in accordance with the methodologies specified in Appendix W. We recommend use of AERMET-derived mixing heights instead of WRF-derived mixing heights. It must be shown, through a thorough modeling performance analysis, the WRF dataset is appropriate for use in NSR in the region of the proposed source. Section 3.2.6 does not offer a sufficiently detailed explanation of how the model performance analysis will be conducted. It would be best if model performance analysis was included in the modeling protocol.

			II. If option I is not feasible or the model performance analysis reveals poor WRF performance, we recommend the applicant produce a 3-year WRF dataset up to 1 km resolution, using archived meteorological reanalysis data to drive WRF. The applicant should append the protocol to outline all WRF settings and methods used in this case. The NSR application should include a thorough model performance of the WRF modeling. We recommend use of AERMET-calculated mixing heights instead of WRF-calculated mixing heights. III. If options I or II are not feasible or the model performance analyses show poor WRF performance, we recommend a 1-year PSD-quality site-specific meteorological dataset be collected at or near to the site of the proposed source. Ecology must approve a Quality Assurance Performance Plan that conforms with current PSD-monitoring guidance.
4	2.2.6	Tier 2 NO_2 models	Note ARM2 is now the regulatory Tier 2 model for NO_2 modeling. The ARM method is now considered a non-regulatory modeling method. However, the 1-year transition period allows for flexibility in the application of these models if Ecology has technical reasons to believe ARM is the more appropriate model in this case. Region 10 would highly recommend ARM2 be used for Tier 2 modeling. If Tier 3 modeling is requested, please consult with EPA Region 10, as required under Appendix W for application of Tier 3 NO2 models.
5	2.3	SILs	Region 10 would recommend the State allow the use of the interim SILs, as proposed, if the State concludes the SILs are appropriate given the nature of the proposed source and climatology of the region. The EPA will be releasing final ozone and $PM_{2.5}$ SILs guidance by early 2018 (draft guidance is currently available). This guidance will contain documentation providing strong regulatory and legal justification for use of SILs. Region 10 would recommend the applicant include a review of all background design concentrations to assure sufficient "head room" for use of the SILs to comply with current guidance (EPA-454/B-14-001).
6	2.3	Use of MERPs for secondary $PM_{2.5}$ and ozone	Use of the draft MERP guidance is proposed for Class II receptors only. The MERPs guidance provides example calculations of emission thresholds based on Class II SILs. The applicant is assuming MERPs guidance is not applicable to Class I areas. The modeling results used in the draft MERPs guidance is not specific to Class II or Class I areas. However, the example calculations used to define MERP thresholds are based on Class II SILs. The modeling results reported in the guidance could be used to determine MERPs thresholds for Class I areas or be used to estimate conservative air quality impacts for NAAQS evaluations. However, Region 10 would recommend the MERPs guidance only be used for cumulative analysis purposes in the case where the background design concentrations are significantly below the NAAQS and where the facility emissions do not significantly exceed the emission rates used in the MERPS guidance (for example, a 3000 TPY source would significant exceed the 1000 TPY hypothetical sources used in the MERPs guidance).
7	2.3, last paragraph	Reference to Mar. 4 2013 PM2.5	Just to note: the March 4, 2013 draft guidance referred to here was finalized on May 20, 2014 (document EPA-454/B-14-001). The draft MERPs guidance does not supersede the EPA-454/B-14-001, but offers methods to comply with Appendix W

		modeling guidance	parts 5.3.2 and 5.4.2. The recommendations in the May 20th 2014 guidance do not necessarily conflict with the requirements of part 5.4.2. The MERPs approach offers a preferred method to conduct the preliminary Source Impact Analysis outlined in the May 20th 2014 guidance.
8	2.6	Class II increment	Region 10 recommendation: The modeling protocol should be amended to identify major and minor source baseline dates and identify for which pollutants increment consumption analysis will be needed.
9	2.7	Nearby source emissions	If emissions from nearby sources are needed for the NAAQS analysis (if a source can cause a significant concentration gradient in the vicinity of receptors where the SIL is exceeded), then Region 10 recommends the nearby source emissions comply with Appendix W Table 8-2 guidance. Note: guidance recommends emission factors be based on actual operating conditions, not "actual emissions" as defined in 40 CFR 52.21(b)(21)(i).
10	2.7	Background values – hour-of-day	If hour-of-day backgrounds are proposed for use, the applicant should work closely with Ecology to confirm the situation justifies use of this approach.
11	2.9	MERPs for ozone	Some discussion should be added to note Source 18 from the MERPS guidance (EPA-454/R-16-006) is also representative of the area in question given its proximity and similar climate and background chemical and emissions loading. The applicant plans to conduct a Tier 2 analysis using Ecology-provided modeling files. Region 10 recommends the methodology for the Tier 2 ozone analysis be outlined in the modeling protocol.
12	3.1	Kalispel and Spokane tribes have not requested AQRV protections. However, visibility analysis is warranted under the additional impact requirements.	Although the Kalispel and Spokane Tribes do not have any specific AQRV protection requirements, the Kalispel Tribe has requested Ecology require an evaluation of local visibility impacts in the Class II areas and Kalispel Tribal land areas in the region of the proposed facility (request was given verbally and discussed during the modeling protocol meeting). This evaluation would fulfill the requirements under 52.21(o), "additional impact analyses." This requires the applicant to assess visibility impacts that may result due to project emissions in the vicinity of the source. However, the requirement does not state how an analysis should be performed or what level of degradation qualifies as a significant impairment. For near-field visibility impairment analysis, we recommend the applicant prepare a multi-faceted qualitative analysis based on the results from a visibility screening model such as PLUVUE II, the primary PM impacts from the AERMOD modeling, and possibly visibility impacts as determined from the CALPUFF AQRV analysis (receptors can be placed in the Kalispel Reservation boundaries and necessary inputs adopted from the nearest or most representative nearby Class I areas). The qualitative analysis should predict how impacts from the proposed source might affect visibility in the region, guided by the results of the modeling. The modeling protocol should be expanded to outline the method, as required by Ecology.
13	3.1	$PM_{2.5}$ Class I increment analysis	The applicant insists the draft MERPs guidance is not applicable to Class I areas. Although we disagree with this assumption (the modeling results used in the draft guidance could be applied to Class I areas also), we do agree the impact determined using MERPs guidance could be excessively conservative for evaluation of secondary pollutant impacts far downwind of the facility. As shown in the draft MERPs guidance, the maximum ozone impacts rarely occur more than 30 km from

			the source. Maximum $PM_{2.5}$ impacts from SO_2 and NO_x emissions rarely occur more than 50 km and 100 km from the source, respectively. However, the Kalispel Reservation is located 22 km from the proposed source. The median maximum secondary impact is generally in the range of 20-30 km, according to the evaluation contained in the draft MERPS guidance. Therefore, we would recommend the secondary PM2.5 impacts determined using the draft MERPs guidance be considered for use in a SIL or cumulative analysis of Class I increment consumption of the near-field (< 50 km) Class I areas.
14	3.1	Class I >50km screening technique for increment analysis	A 3-tier system for Class I increment analysis is proposed: a) AERMOD 50km arc b) CALPUFF screening c) Design value lookup tool approach The first two tiers follow current guidance in Appendix W. The proposed methodology for Tier A is sound and in line with previous EPA recommendations. For Tier B, the applicant could use the older EPA-approved version or more modern versions of CALPUFF, but chemistry must be turned off. The Tier C approach is unorthodox: if a Tier C approach is necessary, we advise requesting guidance from EPA's Model Clearinghouse.
15	3.2	AQRV analysis	Region 10 did not evaluate the AQRV methodology because the responsibility is under the purview of the Federal Land Managers.

Comments on Hi-Test Sand PSD Modeling Protocol
Submitted by Kalispel Tribe of Indians
October 2017

HiTest Sand, LLC (HiTest) proposes to construct and operate a silica smelter near Newport, WA along the Washington-Idaho state boundary. In support of an expected permit application under the Prevention of Significant Deterioration (PSD) regulations, HiTest has submitted an air quality dispersion modeling protocol for review by Washington Department of Ecology (Ecology). The protocol was prepared by HiTest's consultant, Ramboll Environ US Corporation. The Kalispel Tribe of Indians submits these comments to Washington DOE on the proposed modeling protocol.

This project will require a PSD permit, with source emissions for sulfur dioxide (SO_2) and nitrogen oxides (NO_x) exceeding 700 tons per year (tpy) each. The Tribe expects that the HiTest permit application, including dispersion modeling, will conform to applicable US Environmental Protection Agency (EPA) and Ecology guidelines and standards for PSD permits. The modeling protocol in its present form falls short of this requirement.

The protocol does indicate that the applicant's modeling will address the Kalispel Reservation as a Class I area and that approach is appreciated by the Tribe.

Major Concerns:

1. The meteorological data planned for the modeling is inadequate and does not conform to the applicable regulations and modeling guidelines. Under EPA's Guideline on Air Quality Models (40 CFR 51, Appendix W) and related guidance, the meteorological input data for dispersion modeling need to be spatially representative of the project site and also collected with known precision and accuracy. In addition to Appendix W, the relevant data requirements are addressed in EPA guidance such as Meteorological Monitoring Guidance for Regulatory Modeling Applications and the Ambient Monitoring Guidelines for Prevention of Significant Deterioration. The HiTest modeling protocol lacks any discussion of how the proposed meteorological data inputs conform to the requirements of the applicable guidelines. The Kalispel Tribe is also skeptical that the data selected can meet the applicable data requirements and reasonably support a PSD permit application. As such, the Tribe recommends that the applicant to conduct an on-site meteorological monitoring program for a minimum time period of one year in order to collect adequately representative data for use in the air dispersion modeling.

2. The modeling protocol indicates that the Modeled Emissions Rates for Precursors (MERP) guidance will not be used for Class I areas, such as the Kalispel Reservation. However, no alternative proposal for addressing the secondary PM-2.5 impacts is listed in the protocol. Any modeling of PM-2.5 impacts to the Kalispel Reservation needs to include an assessment for secondary PM contributions. If the applicant elects not to use the MERP approach, an alternative method is required.

Specific Technical Comments – Meteorological Data

1. Page 6: The protocol indicates that a five year data set spanning 2012-16 is planned, but the proposed ID41 met tower was apparently not installed until the end of 2013. The protocol should clarify this discrepancy. Based on discussions at the recent pre-application meeting, the Tribe's understanding is that the 2012-16 five year data set will be from National Weather Service (NWS) observations at Deer Park WA, with a second modeling data set from the 2014-16 ID41 data. The applicant should specifically list in the protocol the exact data to be used for the PSD permit modeling.

2. Data Representativeness: The EPA Modeling Guidelines (Appendix W) at Section 8.4 lists the regulatory requirements for meteorological data inputs used for permit modeling. The applicant needs to address how the data selected conform to the Guideline requirements for data representativeness. The Tribe is especially concerned regarding the planned use of the Deer Park Airport data as not being spatially representative of the proposed project site. The protocol (Page 6) also indicates that the instrument siting at ID41 may not meet the applicable EPA sensor siting guidelines. Based on the local topography, a reasonable expectation is that emissions transport would be parallel to the Pend Oreille River and that emissions would be carried from the proposed HiTest plant site toward the Kalispel Reservation. However, the protocol shows that the selected data have infrequent winds toward the Kalispel Reservation, which is contrary to reasonable expectations based on the local terrain. All of these factors suggest problems with data representativeness that have not been adequately addressed by the protocol. Ecology should not approve these Deer Park and ID41 data for use in the HiTest PSD permit modeling until all concerns regarding data representativeness are addressed.

3. In order to better illustrate the Tribe's concerns over data representativeness, a wind rose from the Hoodoo, ID RAWS station is attached (Figure 1). Hoodoo is about 20 kilometers (km) southeast of the proposed plant site (Figure 2). The Hoodoo data show distinctly different wind patterns compared to the ID41 and Deer Park data. The Hoodoo data indicate a predominance of winds from the east through south sectors, winds that would carry plant emissions toward the Kalispel Reservation. At this time, the Tribe is not recommending that the Hoodoo data be used in the HiTest PSD modeling without thoroughly vetting these data for data representativeness and quality as described elsewhere in these comments. However, the Hoodoo RAWS data show wind patterns more in line with expectations given the local topography of the area and illustrate why the Kalispel Tribe has concerns over the representativeness of the Deer Park and ID41 data recommended by the applicant.

4. Data Quality: No detailed information is presented by the applicant to allow an assessment of the data quality for the ID41 site. The desired specifications for meteorological sensors used in regulatory modeling are presented in EPA's Meteorological Program Guidance, specifically Tables 5-1 and 5-3. Does the monitoring equipment at ID41 meet these criteria? Also, EPA's PSD Monitoring Guideline at Section 5.2 discusses exposure of the meteorological instruments. The ID41 instrument

exposure is not addressed in the protocol other than a brief comment that nearby obstacles such as trees might interfere with the measurements. The limited information provided by the protocol in fact casts serious doubts on the overall ID41 data representativeness and data quality. Lastly, Section 7.0 in EPA's PSD Monitoring Guidelines discusses quality assurance for PSD-level data, including recovery requirements for valid data, requirements for periodic calibration of the meteorological sensors, and requirements for an independent sensor audit. Unless the applicant can show that the ID41 data meet the applicable data quality requirements from EPA guidelines governing on-site data collection, Ecology should not allow their use in the HiTest PSD permit application.

Specific Technical Comments - Secondary PM Impacts

1. Page 21: The protocol indicates that the MERP guidance is not applicable to Class I areas. The applicant needs to provide the technical/regulatory basis to support that statement; otherwise, the claim has no credibility.

2. The Kalispel Tribe would support the MERP approach to address the contribution of secondary PM to the modeled PM-2.5 concentrations. Based on the modeling protocol (Page 19), this would add 0.50 micrograms per cubic meter to the modeled 24-hour PM-2.5 concentration. However, if the MERP approach is not desired by the applicant, an alternative modeling approach for addressing secondary PM formation is needed. The proposed source will release SO_2 and NO_x and over 700 tpy each, and the formation of secondary PM from these SO_2 and NOx precursor emissions needs to be addressed in some fashion for impacts at Class I PSD areas.

Other Technical Comment

1. Page 4 (Emissions Inventory): The HiTest PSD modeling should be based on appropriate emission limits for the averaging time of interest (1-hr, 3-hr, 24-hr, etc.). The Kalispel Tribe expects that the PSD permit issued by Ecology will contain appropriate permit limits derived in part from the emission rates used in the modeling.

2. Page 9 (Average Surface Moisture): The protocol indicated that average surface moisture characteristics will be used. Instead, local precipitation data should be used to determine the appropriate surface moisture for input to the model on a year-by-year basis. Average moisture should not be assumed in AERMET/AERMOD if it is known that the year being modeled is a wet or dry year.

3. Page 15-16 (PSD Increment Inventory): The protocol correctly notes that whether or not a nearby source consumes PSD increment is determined using the PSD baseline date. However, these dates may be different depending on the location of the increment consuming source. For example, the SO_2 baseline date for the Eastern Washington control region is 8/31/79 and for the Northern Washington control region is 6/28/81. A single PSD baseline date would not be applicable for all of the PSD increment inventory.

4. Page 17 (Modeling for Toxic Air Emissions): Like Washington, the State of Idaho has concentration thresholds for potential impacts of toxic air contaminants. AERMOD receptors located in Idaho should be evaluated against the appropriate toxic contaminant concentration thresholds for Idaho.

5. Page 21 (Receptor Density at Kalispel Reservation): Depending on the modeling results and the margin of compliance with Class I increments, additional modeling receptors with a spacing of less than 200 m may be needed within the Kalispel Reservation.

6. Page 22 (Class I Significant Impact Levels): The Kalispel Tribe expects that any exceedance of the applicable Class I SIL would trigger a cumulative modeling analysis for Class I PSD increment compliance, including cumulative PSD increment impacts at the Kalispel Reservation.

Figure 1

Hoodoo, ID RAWS Station Wind Rose
Period of Record: September 1, 2012 through August 31, 2017

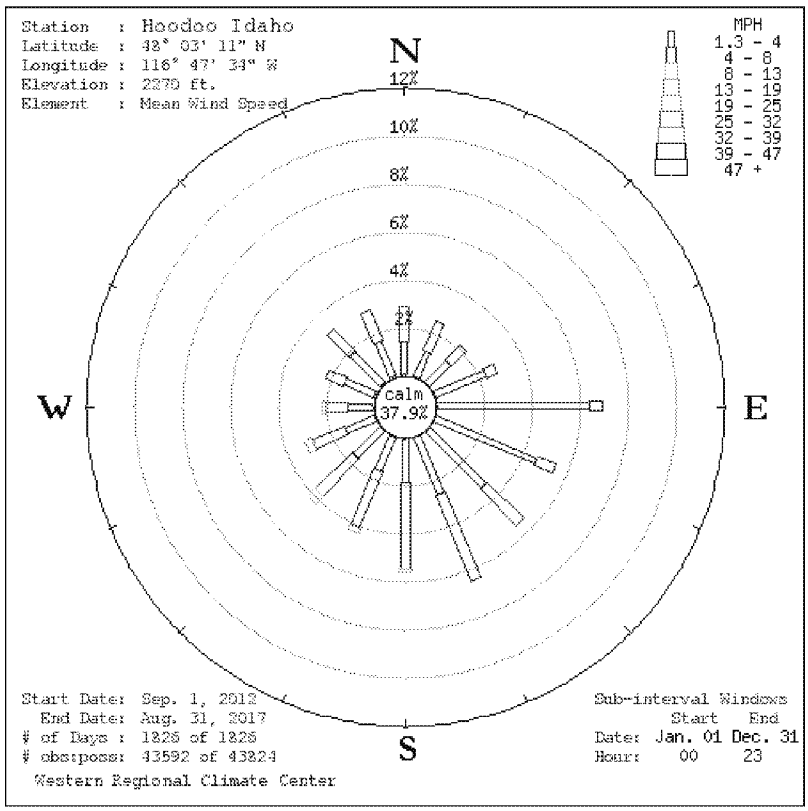
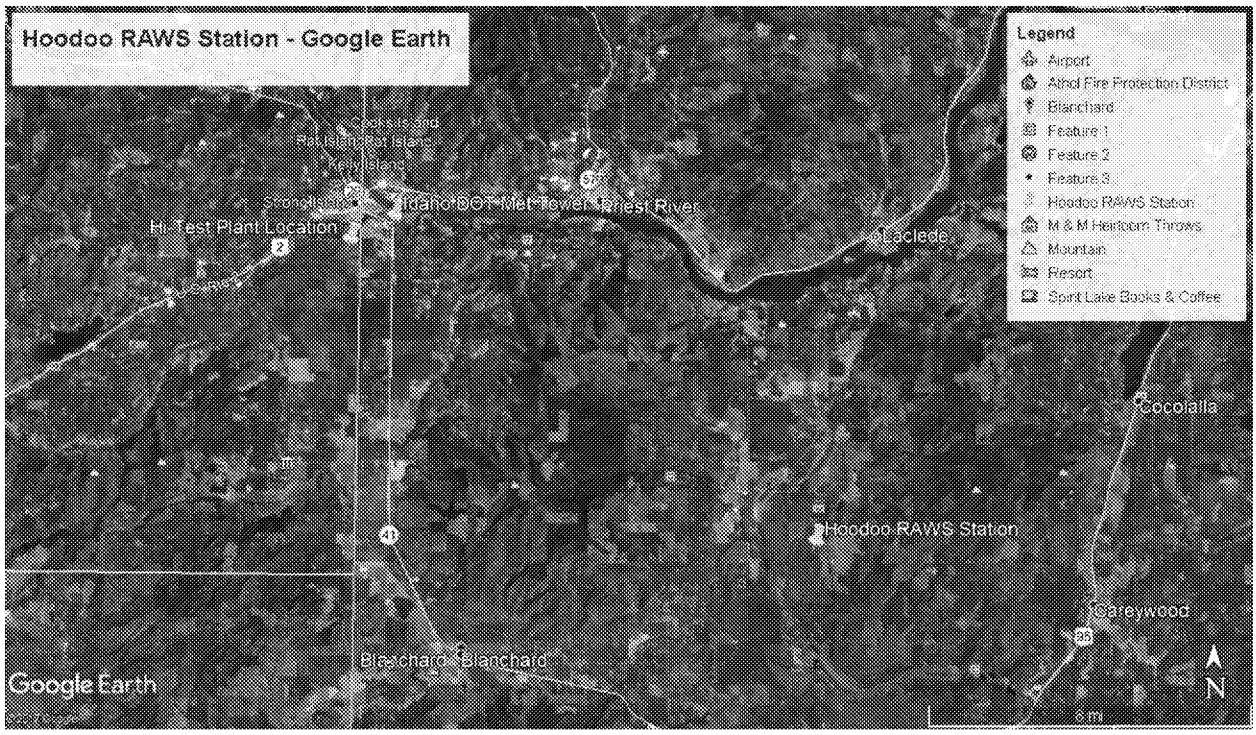


Figure 2

Hoodoo RAWS Station Location Relative to HiTest Plant Site



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Project Number:
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PROPOSED USE OF CALPUFF FOR FAR-FIELD CUMULATIVE PSD INCREMENT ANALYSIS

ALTERNATIVE MODEL APPROACH JUSTIFICATION

RAMBOLL

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1. INTRODUCTION

PacWest Silicon, Inc (PacWest) proposes to construct a high-quality silicon manufacturing facility near Newport, Washington. Initial sulfur dioxide (SO_2) emissions estimates were presented in the PSD modeling protocol.

Dispersion modeling of the estimated emissions from the proposed facility leads to predicted concentrations exceeding the Class I Significant Impact Levels (SILs) for SO_2 at the Cabinet Mountains Wilderness area, a mandatory Class I area approximately 94 km from the proposed facility. Because the minor source baseline for SO2 in western Montana has not yet been triggered, no cumulative Class I PSD increment analysis will be required.

Dispersion modeling also predicts concentrations exceeding Class I SILs for SO2 in the Kalispel Indian Reservation, which the EPA has proposed[1] redesignation as a Class I area. The minor source baseline date for SO2 in Pend Oreille County is June 28, 1981, so a cumulative Class I PSD increment analysis for SO2 will be required. Because the Kalispel Indian Reservation is entirely inside a radius of 50 km from the proposed facility, the required cumulative Class I PSD increment analysis will be performed using the current regulatory-default near-field dispersion model, AERMOD, following the procedures detailed in the PSD Modeling Protocol.

However, dispersion modeling also predicts concentrations exceeding the 24-hour and 3-hour Class I SO2 SILs at the Spokane Indian Reservation, a redesignated Class I area 54 km from the proposed facility. Because the minor source baseline for SO2 has been triggered, a cumulative Class I PSD increment analysis for SO2 will be required. Because the proposed facility is more than 50km from the Spokane Indian Reservation, the regulatory-default near-field model cannot be used.

Until May 22, 2017, CALPUFF v5.8.5 was a regulatory-default dispersion model that could be used for far-field (> 50 km) applications. Because CALPUFF is no longer considered a regulatory-default dispersion model, it is necessary to seek

[1] Published in the Federal Register on 10/31/2019, 83 FR 54691 pages 54691-54696, available at https://www.govinfo.gov/content/pkg/FR-2018-10-31/pdf/2018-23474.pdf

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Alternative Model Approval (AMA) from the EPA Model Clearinghouse before CALPUFF can be used for a far-field cumulative Class I PSD increment analysis.

PacWest proposes to use CALPUFF v5.8.5 to perform the far-field modeling for the required cumulative Class I PSD increment analyses. PacWest further proposed to use 4km resolution WRF output, processed through the Mesoscale Model Interface program (MMIF), as the meteorological dataset for CALPUFF. The same WRF simulation will be used for the near-field modeling and the far-field modeling. The near-field modeling will use output from the 1.3 km WRF domain, processed through MMIF in AERMET mode, while the far-field modeling will use output from the 4 km WRF domain, processed through MMIF in CALPUFF mode. A WRF model performance evaluation has been submitted together with the PSD Modeling Protocol, and presents an evaluation following Section 2.6 of the PM2.5 and Ozone guidance[2] of the 4km WRF output.

The remainder of this technical document is a generalized justification for the use of CALPUFF v5.8.5 for far-field Class I PSD increment analyses.

2. CALPUFF REGULATORY STATUS

In the 2016 revision[3] to the Guideline on Air Quality Models (Appendix W to 40 CFR 51, hereafter referred to as "Appendix W" or the *Guideline*) that became effective on May 22, 2017, the CALPUFF Lagrangian Puff Model (California Puff; Scire et al., 2000b) was removed from Appendix A to Appendix W. This action "delisted" it as an Environmental Protection Agency (EPA)-preferred long-range dispersion model. Although Appendix W does not forbid the use of a near-field dispersion modeling for source-receptor distances greater than 50 km, Section 4.1(c) of Appendix W states that a near-field model at distances beyond 50 km is likely conservative and the location of impacts is unreliable.

A Class I Prevention of Significant Deterioration (PSD) increment analysis is a required component of a PSD application. The first step in such an analysis would be to perform dispersion modeling of the PSD project-specific emissions, and compare predicted concentrations to the relevant Class I Significant Impact Levels (SILs). If the predicted concentrations do not exceed the SILs, then no

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[2] Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, and Regional Haze, https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf

[3] See https://www3.epa.gov/ttn/scram/appendix_w-2016.htm

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further analysis is required. If the predicted concentrations exceed the SILs, a cumulative Class I PSD increment analysis would be required to ensure that the addition of the proposed facility will not lead to Class I PSD increment exceedances. Typically, the emissions inventory for such an analysis would include sources both less than and greater than 50 km from the Class I area. The sources location more than 50 km from the Class I area would require a far-field dispersion model, such as CALPUFF.

Because CALPUFF is no longer considered a regulatory-default dispersion model, it is necessary to seek Alternative Model Approval (AMA) from the EPA Model Clearinghouse before CALPUFF can be used for regulatory applications. For such an approval, it must be shown that CALPUFF meets the requirements specified in Section 3.2.2(e) of Appendix W. These requirements include:

i) The model or technique has received a scientific peer review;

ii) The model or technique can be demonstrated to be applicable to the problem on a theoretical basis;

iii) The databases which are necessary to perform the analysis are available and adequate;

iv) Appropriate performance evaluation of the model or technique have shown that the model or technique is not inappropriately biased for regulatory application; and

v) A protocol on methods and procedures to be followed has been established.

In addition, the AMA will be subject to public notice and comment, as mentioned under 49 CFR 51.166(l)(2) under procedures established in 40 CFD 51.102.

This technical document provides justification that CALPUFF version 5.8.5 is appropriate for use in a far-field cumulative Class I PSD increment analyses. This report provides evidence to satisfy each alternative model justification condition presented in Section 3.2.2(e) of Appendix W ('Alternative Models: Requirements').

This document does not address later versions (v6.x or v7.x) of CALPUFF, but focuses instead on the last regulatory-default version (v5.8.5). This document

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does not address the specific CALPUFF/CALPOST/POSTUTIL settings to be used, or the details of the meteorological dataset used to drive CALPUFF, or the choice of the pre-processor program used to create that dataset. Those decisions should be addressed in a PSD Modeling Protocol that should be submitted as part of a PSD permitting procedure.

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3. ALTERNATIVE MODEL JUSTIFICATION

This section provides technical documentation to address each condition outlined in Appendix W Section 3.2.2.

3.1 The Model or Technique has Received Sufficient Scientific Peer Review

A summary of the scientific peer review literature that supported the original 2003 decision to list CALPUFF as an EPA-preferred model is presented in this section. In addition, this section briefly summarizes the decisions, policy, and guidance surrounding the far-field regulatory application of CALPUFF.

3.1.1 Decisions, Policy, Guidance Surrounding Far-Field Application of CALPUFF

The CALPUFF model, originally developed by Earth Tech, Inc., is a Lagrangian Gaussian puff model with the ability to simulate continuous plumes using overlapping puffs. From April 2003 through May 2017, CALPUFF was the EPA-preferred model for long-range transport assessments of the National Ambient Air Quality Standards (NAAQS) and PSD increments.

In April 2000, a Federal Register notice proposed the adoption of the CALPUFF modeling system to support long-range transport and dispersion applications related to the characterization of source impacts in Class I areas. The Federal Register notice also proposed that CALPUFF could be used for complex wind modeling scenarios on a case-by-case basis. Upon completion of the public comment period, CALPUFF was adopted as an EPA-preferred dispersion model in April 2003. A Federal Register notice[4] released on April 15, 2003 officially promulgated CALPUFF as the preferred technique for assessing long-range transport of pollutants and their impacts on Federal Class I areas.

Prior to adoption of CALPUFF as an EPA-preferred model for long-range transport applications, CALPUFF was subject to scientific peer review, summarized in the following section. Additionally, the Interagency Workshop on Air Quality Modeling (IWAQM) investigated potential regulatory applications involving CALPUFF in their Phase I and Phase II reports (EPA, 1993 and 1998). As noted in the April 15, 2003 Federal Register notice, significant consultation with reviewing authority (paragraph 3.0(b)) must be undertaken during a long-range

[4] https://www.federalregister.gov/documents/2003/04/15/03-8542/revision-to-the-guideline-on-air-quality-models-adoption-of-a-preferred-long-range-transport-model

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transport modeling assessment. The Federal Land Managers (FLMs) responsible for protecting air quality related values (AQRVs) in the affected area may provide appropriate procedures and analysis techniques. In accordance with Section 165(d)(2)(C)(iii) of the Clean Air Act, if there is a Class I increment violation, the facility must sufficiently demonstrate that emissions from the proposed sources will have no adverse impact on the AQRVs.

In 2005, EPA coordinated a CALPUFF workgroup to begin elucidating issues surrounding the 1998 IWAQM Phase II recommendations, including the comparison of CALPUFF model results to tracer measurements from two field campaigns. In May 2009, EPA released a reassessment of the IWAQM Phase II recommendations (EPA, 2009a) that raised issues with settings used in recent CALMET (a CALPUFF meteorological pre-processor) model applications.

In November 2010, the CALPUFF developers (TRC) announced a new CALPUFF release (version 6) that contained two new chemistry options[5]. The improved chemical mechanisms were designed to alleviate overestimates in modeled sulfate and nitrate. CALPUFF version 6 was not adopted as an EPA-preferred model and will not be used for the far-field cumulative Class I PSD increment analysis discussed in this report.

Alongside the 2016/17 Appendix W Final Rule, EPA provided guidance for a screening approach for long-range transport assessments of the NAAQS and PSD increments using Lagrangian models, including CALPUFF. Simultaneously, CALPUFF was delisted as an EPA-preferred model for long-range transport applications. CALPUFF may still be used for (AQRV) assessments under FLM guidance (FLAG, 2010) and may be justified for near-field use in regions with complex terrain[6]. Prior to de-listing, CALPUFF version 5.8.5, CALMET version 5.8.5, and CALPOST version 6.221 were the EPA-preferred release versions.

3.1.2 Summary of Scientific Peer Review Literature

This section summarizes the scientific peer review literature that was cited in support of the original 2003 decision that led to the promulgation of CALPUFF as the EPA-preferred model for long-range transport applications.

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[5] http://www.src.com/calpuff/calpuff1.htm
[6] http://www.src.com/calpuff/regstat.htm

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3.1.2.1 Background

Prior to promulgation, substantial peer review of the CALPUFF modeling system was performed to ensure that the CALPUFF modeling system was scientifically sound[7]. In 1998, the EPA contracted the KEVRIC Company Inc. to perform a multi-faceted peer review of the modeling system. The reviewers included Dr. K. Jerry Allwine, Dr. Walter F Dabberdt, and Mr. Larry L. Simmons. The peer review literature consisted of detailed reviews of the following documents:

1. User's Guide of the CALMET meteorological pre-processor
2. User's Guide for the CALPUFF dispersion model
3. IWAQM Phase II Final Report and Summary: Recommendations for Modeling Long Range Transport Impacts. EPA-454/R-98/XXX. (EPA, 1998)
4. An executable copy of the code for the CALMET/CALPUFF models.

The four aspects of the CALMET/CALPUFF modeling system that were investigated included model formulation, documentation, performance evaluation, and user friendliness of the entire system. A summary of the primary results, conclusions, and recommendations corresponding to each peer review aspect is presented below.

Note that many of the reviewer comments about CALMET are not included in this technical document because the FLMs have been requesting the use of the Mesoscale Model Inter-Face program (MMIF, Brashers and Emery 2018) in its place. MMIF can use the outputs from mesoscale meteorological models such as MM5 and WRF directly, without having to be processed through CALMET. The use of prognostic (AKA mesoscale) model output, processed via MMIF, in regulatory dispersion modeling is covered in Section 8.4 of Appendix W.

3.1.2.2 Model Formulation

The reviewers noted that the CALMET/CALPUFF modeling system is a state-of-the-art dispersion Lagrangian puff model because it can incorporate mesoscale meteorological model output and its meteorological preprocessor (CALMET) has the ability to treat local effects (e.g., slope flows, terrain blocking, sea breeze).

[7] https://www3.epa.gov/ttn/scram/7thconf/calpuff/calpeer.pdf

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The reviewers stated that CALPUFF is superior to its predecessor, MESOPUFF II, for the following reasons:

1. CALPUFF explicitly treats terrain effects, with respect to both meteorology and dispersion.

2. CALPUFF contains a comprehensive treatment of near-field building impacts on dispersion.

3. CALPUFF contains improved treatment of complex wind fields, puff splitting, boundary layer diffusion, and improved dry deposition using resistance schemes.

The reviewers suggested that the CALMET/CALPUFF system is suitable for both near- and far-field applications and mentioned that EPA should develop a 'regulatory default' modeling protocol that details a specific configuration of acceptable model parameters. It should be noted that this peer review largely focused on information contained in the CALPUFF and CALMET User's Guides and resources did not allow for modeling exercises.

3.1.2.3 Documentation and User Friendliness

The peer review found that the CALMET and CALPUFF User's Guides sufficiently describe model formation and scientific foundations and is well organized. However, reviewers noted that the User's Guides were lacking detailed instructions related to operating the model. The reviewers also suggested that an experienced air modeler should be employed to setup and run CALPUFF once additional instructions were included in the User's Guides. Overall, the reviewers found the CALMET and CALPUFF graphical user interfaces (GUIs) generally easy to use and understand. One reviewer suggested that a tool to visualize three-dimensional (3-D), time-varying wind fields would be helpful.

3.1.2.4 Performance Evaluation

The reviewers stated that CALPUFF performance is likely superior to other models because it contains model formulations and algorithms that have been reasonably well characterized. The reviewers noted that the IWAQM comparisons involving CALPUFF (EPA, 1993 and 1998) have been an important part of the model's performance evaluation and suggested that additional CALPUFF evaluations, sensitivity studies, and characterizations of model uncertainty would continue to be valuable.

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The peer reviewers noted that CALPUFF has been evaluated with data from several field studies but acknowledged that there is a dearth of suitable data that can be used for model-measurement comparison. At the time, an evaluation focused on CALPUFF's secondary pollutant treatment had not yet been performed.

3.1.2.5 EPA Response to 1998 Scientific Peer Review

The EPA provided responses to the peer-review comments[8]. Several of the most relevant comments for this study are briefly described in this section.

Model Formulation

The reviewers suggested that an independent firm thoroughly test the CALPUFF/CALMET modeling system before public release. In lieu of performing additional testing and model performance evaluation, the EPA publicly released CALPUFF with the expectation of receiving feedback from the community.

User Documentation and Instructions

The EPA and the CALPUFF model developer (Earth Tech) provided several tests cases to help guide users through the entire CALPUFF process. These examples were provided as external supplements to the CALMET and CALPUFF User's Guides.

Performance Evaluations

The peer reviewers noted that it would be illustrative to perform additional model evaluation studies involving CALPUFF. As an EPA-preferred model, the EPA expected that CALPUFF would be used in future model evaluation studies.

3.2 The Model or Technique can be Demonstrated to be Applicable to the Problem on a Theoretical Basis

This portion of the technical report provides a general, theoretical review of Lagrangian puff modeling and its appropriateness for far-field air quality impact assessments. A theoretical review and technical summary of CALPUFF and the Weather Research and Forecasting (WRF; Skamarock et al., 2018) models are also provided in this section. The WRF model can be used to provide 3-D gridded meteorological fields to CALPUFF for far-field cumulative Class I PSD increment analyses, directly via the MMIF processor, as per Section 8.4 of Appendix W.

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[8] https://www3.epa.gov/ttn/scram/7thconf/calpuff/respcppr.pdf

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3.2.1 Theoretical Review of Lagrangian Puff Modeling

The fate of pollutants in the atmosphere is highly dependent on the various scales of motion, which range from micro and turbulence scales to urban, regional, and global scales. Emitted pollutants are transported as plumes, which disperse both horizontally and vertically in the atmosphere. While pollutants are undergoing dispersion and transport, chemical transformations may occur, such as nitrogen oxide conversion to ozone and sulfur dioxide conversion to sulfate.

There are several types of atmospheric chemistry and dispersion models, including Gaussian models, Lagrangian models, and Eulerian models. Gaussian models are used to predict the dispersion of continuous or non-continuous plumes originating from near surface-level or elevated sources. The pollutant dispersion is assumed to have a Gaussian, or normal probability, distribution. In Lagrangian dispersion modeling, an observer follows the plume to analyze the change in plume behavior over time, while in Eulerian dispersion modeling, an observer remains stationary and monitors the change in atmospheric concentrations over time. Lagrangian dispersion modeling does not utilize a computational grid (e.g., grid cells) and can resolve pollutant dispersion from multiple sources. Lagrangian models can be used to determine source-receptor relationships and to track air mass trajectories. In Eulerian models, source emissions are instantaneously mixed into model grid cells, so it is difficult to resolve atmospheric dispersion from individual sources. It should be noted that there are some modeling frameworks that combine Gaussian, Lagrangian, and Eulerian techniques (e.g., source apportionment in CMAQ and CAMx, Plume-In-Grid algorithm in CAMx).

3.2.1.1 Effectiveness of CALPUFF Lagrangian Modeling for Far-Field Air Quality Assessment

In 2003, the EPA recommended CALPUFF for long-range transport modeling because of its ability to handle complex 3-D wind fields. In addition, CALPUFF also allows for the estimation of both primary and secondary particulate matter (PM). The 2003 Federal Register notice[9] states that reasonable CALPUFF model performance has been achieved with source-receptor distances up to 300 km.

[9] https://www.federalregister.gov/documents/2003/04/15/03-8542/revision-to-the-guideline-on-air-quality-models-adoption-of-a-preferred-long-range-transport-model

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For over a decade, long-range transport of pollutants was modeled using CALPUFF to support regulatory and compliance decisions. For example, CALPUFF was commonly used to assess the far-field impacts of sources on air quality related values (AQRV, acid deposition and visibility impairment) in Class I areas and other federal land for PSD and National Environmental Policy Act (NEPA) requirements. CALPUFF was also commonly used to predict concentrations and compare them to Class I SILs for the PSD increments, and occasionally to perform cumulative Class I PSD increment assessments. States and multi-jurisdiction planning regions (e.g., WRAP, VISTAS, LADCO, CENRAP) have used CALPUFF for a variety of far-field air quality impact assessments.

3.2.2 Review and Technical Summary of CALPUFF Model

CALPUFF is a multi-layer, multi-species, non-steady-state Lagrangian gaussian puff dispersion model. The CALPUFF modeling system also contains a post-processor that calculates time-averaged concentrations, depositional fluxes, and visibility parameters (CALPOST). CALPUFF simulates the temporally and spatially changing impacts of terrain and meteorology on atmospheric dispersion.

CALPUFF contains modules to simulate complex terrain, overwater transport, coastal interaction (e.g., sea breeze), building downwash, wet and dry deposition, and simplistic chemical reactions. Table 2-1 provides a summary of the features available in the CALPUFF model.

Table 2-1: CALPUFF Model Features[1]

Feature	Description
Source Types	Point; Line; Volume; Area
Non-steady-state Emissions and Meteorological Conditions	Gridded 3-D fields of meteorological variables; spatially-variable fields of mixing height, friction velocity, convective velocity scale, Monin-Obukhov length, preciptation rate; Vertically and horizontally-varying turbulence and dispersion rates; Time-dependnet source and emissions data
Efficient Sampling Functions	Integrated puff formation; elongated puff (slug) formation
Dispersion Coefficient Options	Direct measurements of σ_v and σ_w; estimated values of σ_v and σ_w based on similarity theory; Pasquill-Gifford (PG) dispersion coefficients (rural areas); McElroy-Pooler (MP) dispersion coefficients (urban areas); CTDM dispersion coefficients (neutral/stable)

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Feature	Description
Vertical Wind Shear	Puff splitting; differential advection and dispersion
Plume Rise	Partial penetration; buoyant and momentum rise; stack tip effects; vertical wind shear; building downwash effects
Building Downwash	Huber-Snyder method; Schulman-Scire method
Subgrid Scale Complex Terrain	Dividing streamline (H_d): Above H_d, puff flows over the hill and experiences altered diffusion rates; below H_d, puff deflects around the hill, splits, and wraps around the hill
Interface to the Emissions Production Model (EPM)	Time-varying heat flux and emissions from controlled burns and wildfires
Dry Deposition	Gases and particulate matter; three options, including: full treatment of space and time variations of deposition with a resistance model, user-specified diurnal cycles for each pollutant, no dry deposition
Overwater and Coastal Interaction Effects	Overwater boundary layer parameters; abrupt change in meteorological conditions and plume dispersion at coastal boundary; plume fumigation; option to introduce subgrid scale Thermal Internal Boundary Layers (TIBLs) into coastal grid cells
Chemical Transformation Options	Pseudo-first-order chemical mechanism for SO_2, SO_4, NO_x, HNO_3, and NO_3; user-specified diurnal cycles of transformation rates; no chemical conversion
Wet Removal	Scavenging coefficient approach; removal rate a function of precipitation intensity and preciptation type
Graphical User Interface	Point-and-click model setup and data input; enhanced error checking of model inputs; online help files

[1]Table adapted from Table 1-1 of the CALPUFF User's Guide: http://www.src.com/calpuff/download/CALPUFF_UsersGuide.pdf

Source parameters, emissions, meteorology, terrain, receptor grid, and projection information must be defined in the CALPUFF input file. The CALPUFF input file also contains settings for various chemistry and deposition options. The file output settings can also be specified in the input file (e.g., timeseries or summed output).

The CALPOST post-processor contains algorithms recommended by FLAG for assessing the change in plume extinction associated with source emissions. CALPOST is also able to calculate dry and wet deposition fluxes for nitrogen and sulfur consistent with the FLAG 2010 guidance. Typical model output includes hourly, multi-hourly and annual average concentrations for SO_2, NO_x, $PM_{2.5}$, SO_4, HNO_3 and NO_3. Various settings can be specified in the CALPOST input file prior to running the post-processing program.

3.2.3 Review and Technical Summary of Mesoscale Model Interface Program

Using MMIF, prognostic meteorological model output can be converted into model-ready format for several dispersion models, including AERMOD, SCICHEM, and CALPUFF[10]. MMIF is currently designed to read in model output from WRF (Advanced Research WRF core, versions 2 and 3) as well as the Fifth Generation Mesoscale Meteorological Model (MM5, version 3). Meteorology can be extracted for individual points or for a gridded domain. MMIF can extract WRF or MM5 meteorology for multiple vertical layers and perform vertical interpolation, if needed. The algorithms in MMIF can calculate certain meteorological parameters that are not available in WRF or MM5. MMIF can also re-calculate certain parameters (such as boundary layer height) using different algorithms than those used in the prognostic meteorological model.

For use with CALPUFF, MMIF generates three files:

- Useful Information Text File: A text file that contains certain keywords and corresponding values (e.g., projection, vertical layers) that must be entered into a CALPUFF input file
- CALMET.DAT-Formatted File: CALPUFF-ready meteorological input files
- Surfer Grid File (GRD): CALPUFF-ready terrain file containing extracted terrain elevations from the prognostic mesoscale meteorology model

Because MMIF produces CALPUFF-ready meteorology and terrain files, it is not be necessary to run CALMET for the far-field cumulative Class I PSD increment analysis.

[10] https://www3.epa.gov/ttn/scram/models/relat/mmif/MMIFv3.4_Users_Manual.pdf

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3.3 The Databases which are Necessary to Perform the Analysis are Available and Adequate

This section includes a summary of CALPUFF availability, including a summary of the publicly-available pre-processors and post-processors, documentation, and guidance. The Alternative Dispersion Model section of the EPA SCRAM website[11] contains links for CALPUFF, CALMET, and CALPOST that will direct the user to the Exponent website[12], the current developers of the modeling system. The SCRAM website also contains links to download MMIF. The resources contained on the Exponent website include executables, source code, associated utilities, selected meteorological data sets, and documentation. Sample input and output files are also available for download to walk users through a demonstration of the full CALPUFF modeling system. Additional support documents from the EPA can be found in the CALPUFF section of the SCRAM website.

As mentioned above, the most recent EPA-approved versions of the CALPUFF modeling system is 5.8.5 for CALMET and CALPUFF, and 6.221 for CALPOST. The EPA-approved version of the CALPUFF modeling system can be found on Exponent's website. Later versions of the CALPUFF modeling system, Versions 6 and 7, are also available for download from the website, although these modeling systems have never been approved by the EPA.

Table 2-2 provides a brief summary of the EPA-approved CALPUFF models, pre-processors, and post-processors publicly available for download. The meteorology and terrain processors are included in this table for completeness, although MMIF can be used to generate meteorology and terrain input files.

Table 2-2. Summary of EPA-Approved CALPUFF Model, Pre-Processors, and Post-Processors[1]

Model, Pre-Processor, or Post-Processor	Description
Model	
CALMET v5.8.5	3-D diagnostic meteorological pre-processor.
CALPUFF v5.8.5	Non-steady-state transport, dispersion, and deposition model.
Post-Processor	
CALPOST v6.221	Postprocessor for CALPUFF: performs visibility calculations, averages and

[11] https://www.epa.gov/scram/air-quality-dispersion-modeling-alternative-models#calpuff
[12] http://www.src.com/

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Model, Pre-Processor, or Post-Processor	Description
	summarizes concentrations and deposition fluxes, determines ranked concentration/flux/plume extinction values, creates list files and plot files. This version includes "Method 8" which utilizes the revised IMPROVE equation per the Federal Land Managers' Air Quality Related Values Work Group (FLAG) revised October 2010 report.
PRTMET v4.34	Lists selected meteorological data from CALMET and creates plot files.
APPEND v2.34	Appends two or more CALPUFF concentration, wet flux, dry flux or relative humidity (visibility) files.
CALSUM v2.34	Sums and scales concentrations or wet/dry fluxes from two or more source groups from different CALPUFF runs.
POSTUTIL	Processes CALPUFF concentration and wet/dry flux files. Creates new species as weighted combinations of modeled species; merges species from different runs into a single output file; sums and scales results from different runs; repartitions nitric acid/nitrate based on total available sulfate and ammonia.
Geophysical Data Processors and Data	
TERREL v3.684	Combines and grids terrain data.
CTGCOMP v2.25	Compresses USGS land use data files.
CTGPROC v2.682	Processes and grids land use data.
MAKEGEO v2.29	Merges land use and terrain data to produce the geophysical data file for CALMET.
Meteorological Preprocessors	
SMERGE v5.57	Combines and formats files of surface meteorological data to produce a single file for use in CALMET
PXTRACT v4.25	Extracts precipitation data from NCDC data sets.
PMERGE v5.32	Processes and merges precipitation data to produce a single file for use in CALMET.
READ62 v5.54	Processes NCDC upper air meteorological data to produce upper air files for CALMET.
BUOY v.1245	Processes buoy data to produce overwater files for CALMET.
[1]Adapated from http://www.src.com/calpuff/download/epa_codes.htm	

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3.4 Appropriate Performance Evaluation of the Model or Technique Have Shown that the Model or Technique is not Inappropriately Biased for Regulatory Application

A summary of the tracer studies and results used to support the 2003 designation of CALPUFF as an EPA-preferred model is provided in this section. In addition, a review of the tracer studies and results for more recent versions of CALPUFF is also provided.

3.4.1 Comparison of CALPUFF Modeling Results to Two Tracer Field Experiments (EPA, 1998a)

3.4.1.1 Background

In June 1998, the U.S. EPA released a report describing a comparison of CALPUFF modeling results to two tracer field experiments[13]. CALPUFF dispersion modeled concentrations were compared to observed tracer concentrations from two short-term field experiments. One experiment was located in South Carolina at the Savannah River Laboratory (SRL) in December 1975 (United States Department of Energy [DOE], 1978) and the other occurred in Norman, Oklahoma in July 1980 (Great Plains Experiment, Ferber et al., 1981). Both field campaigns used a variety of inert tracers to examine the feasibility of replacing sulfur hexafluoride (SF_6) with alternative inert tracers. Inert tracers were released at a source location for 3-4 hours and resultant plume concentrations were observed at monitors placed 100 km to 600 km downwind from the tracer release point.

The 1998 EPA report notes that CALPUFF was also compared to observed tracer concentrations during the INEL field experiment in Idaho Falls, Idaho in April 1977 (Irwin, 1997). The goal of the INEL campaign was to investigate the impact of varying surface and upper air data on transport and dispersion. Irwin observed that lateral dispersion was best characterized when all available meteorological data was used, but there was poor correlation between modeled and observed maximum concentrations no matter which surface and upper air dataset was used. The 1998 EPA report contains the entirety of the Irwin (1997) study in one of its appendices.

3.4.1.2 CALPUFF Model Configuration

For comparison with the tracer studies, the various CALPUFF computation domains covered the extent of the field campaign domains, and the modeled

[13] https://www3.epa.gov/ttn/scram/7thconf/calpuff/tracer.pdf

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receptors matched the placement of actual monitoring sites. Gridded receptors were also used in CALPUFF. Six vertical layers were defined in the CALPUFF modeling (surface-20 m, 20-50 m, 50-100 m, 100-500 m, 500-2,000 m, 2,000-3,300 m), which is similar to the vertical layer structure described in the INEL field experiment (Irwin, 1997). CALMET utilized National Weather Service (NWS) meteorological data (surface and upper air) and on-site data in several states in the southern United States for comparison with the SRL study, and throughout the Midwest for comparison with the Great Plains study. CALMET used the observed surface and upper-air data to create 3-D meteorological fields that vary temporally and spatially. GIS-based land-use data with 20-30 kilometer resolution was incorporated into CALPUFF.

Although several different inert tracers were used in the Great Plains and SRL studies, SF_6 tracer emission rates were used in CALPUFF modeling. Emission rates and stack parameters in CALPUFF were comparable to those from the field campaigns.

3.4.1.3 Fitted Gaussian Plume Model Performance Metrics

CALPUFF performance was evaluated by calculating the predicted and observed cross-wind integrated concentration, the azimuth of plume centerline, and the second moment of tracer concentration (i.e., lateral dispersion of the plume). The cross-wind integrated concentration is calculated using trapezoidal integration across average monitor concentrations along the receptor arc. If concentrations along the arc are assumed to follow a Gaussian distribution, a fitted plume centerline concentration can be calculated from the cross-wind integrated concentration and the horizontal extent of the plume. CALPUFF model performance was also evaluated by comparing the temporal characteristics of the observed and modeled plumes (e.g., plume arrival time at receptors).

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Table 2-3 summarizes the spatial, temporal and concentration statistical performance metrics used in the fitted Gaussian plume evaluation methodology.

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Table 2-3. Model Performance Metrics Used in the Fitted Gaussian Plume Evaluation[1]

Statistics	Description
Spatial	
Azimuth of Plume Centerline	Comparison of the predicted angular displacement of the plume centerline from the observed plume centerline of the arc
Plume Sigma-y	Comparison of the predicted and observed fitted plume widths (i.e., dispersion rate)
Temporal	
Plume Arrival Time	Compare the time the predicted and observed tracer clouds arrive on the receptor arc.
Transit Time on the Arc	Compare the predicted and observed residence time on the receptor arc.
Concentration	
Crosswind Integrated Concentration	Compares the predicted and observed average concentrations across the receptor arc.
Observed/Calculated Maximum	Comparison of the predicted and observed fitted Gaussian plume centerline (maximum) concentrations and the maximum concentration at any receptor along the arc.
[1]Adapted from Table ES-1 from ENVIRON (2012)	

3.4.1.4 Comparison of Observed and Modeled Concentrations

For all three tracer studies described in the EPA report (1998), CALPUFF predicted similar plume arrival times and plume transit times on the receptor arcs, suggesting reasonable agreement between observed and modeled wind speeds. Observed and modeled wind direction tended to differ by up to 15 degrees. In general, CALPUFF was able to reproduce observed tracer concentrations within a factor of two for both the Savannah River and INEL field campaigns. For the Great Plains field experiment, model-measurement agreement was generally within a factor of 2 or 3, although CALPUFF consistently underestimated the lateral dispersion and overestimated the concentrations associated with the central maximum. It was hypothesized that disagreement between observed and modeled concentrations may be related to sub-par characterization of meteorology in CALMET.

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3.4.2 Documentation of the Evaluation of CALPUFF and Other Long Range Transport Models Using Tracer Field Experiment Data

3.4.2.1 Background

EPA (2012) presents an evaluation of CALPUFF and other long-range transport dispersion models using data from several inert tracer study field campaigns. The dispersion modeling was largely performed by the EPA in the 2008-2010 time period, and builds off previous long-range transport dispersion modeling studies that evaluated CALPUFF using several tracer study field experiments (EPA, 1998a; Irwin, 1997).

In the 2012 EPA report, CALPUFF v5.8 was run using MM5 prognostic meteorology processed by both CALMET and MMIF. The impact of meteorology on CALPUFF model results was analyzed, and CALPUFF model results were also compared to previous CALPUFF evaluation studies. Results from several other long-range transport dispersion models were also compared to the tracer field studies, but those comparisons are not described in detail in this document.

In addition to the two tracer studies used for comparison in the EPA (1998a) report discussed in section 2.4.1 (SRL and Great Plains), results from the 1983 Cross Appalachian Tracer Experiment (CAPTEX) and the 1994 European Tracer Experiment (ETEX) campaigns were also used. During CAPTEX, five 3-hour tracer releases at Dayton, Ohio or Sudbury, Canada were monitored at arcs of sampling sites placed roughly 300 km to 1,000 km away from Dayton, Ohio. During ETEX, two tracer releases occurred in northwest France and tracer concentrations were observed at 168 monitoring sites in 17 countries.

Observed and modeled results were compared using two different approaches. In the first approach, the Savannah and Great Basin field campaign tracer results were compared using the same methodology as used in the EPA (1998a) CALPUFF evaluation (fitted Gaussian plume approach, see Table 2-5). This fitted Gaussian plume approach was performed to evaluate how CALPUFF model performance has improved since the late 1990's. The second model-measurement evaluation approach used the spatial and temporal statistical evaluation framework of ATMES-II (Draxler et al., 2002; Mosca et al., 1998), which utilizes metrics including scatter, bias, correlation, and cumulative distribution. EPA (2012) found that the ATMES-II model performance approach was a better, more comprehensive approach compared to the fitted Gaussian

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plume approach. The ATMES-II model performance evaluation approach is described in more detail in the following section.

3.4.2.2 Spatial, Temporal, and Global Statistics Model Performance Metrics

The model evaluation methodology as employed in ATMES-II (Mosca et al., 1998) and recommended by Draxler et al., (2002) employs three types of statistical analyses:

- Spatial Analysis: Concentrations at a fixed time are considered over the entire domain.
- Temporal Analysis: Concentrations at a fixed location are considered for the entire analysis period.
- Global Analysis: All concentration values at any time and location are considered in this analysis. A global analysis reveals tendencies in overestimation or underestimation (bias and error) and measures scatter and correlation between observed and modeled datasets.

Table ES-2 in EPA (2012) presents all 12 spatial and global statistical metrics used in the evaluation. Some of the more common statistical metrics used are fractional bias, normalized mean squared error, Pearson's Correlation, and rank. The rank statistic combines multiple performance metrics, including correlation, fractional bias, and cumulative distribution.

3.4.2.3 Main Conclusions from the Long Range Transport Model Evaluation presented in ENVIRON (2012)

CALMET Configuration Strongly Impacts Modeled Concentrations

EPA (2012) found that the use of alternative, yet reasonable, CALMET input options led to wide range in modeled concentrations and suggest that CALMET regulatory defaults be provided to ensure consistency between modeling applications.

Comparison of Current CALPUFF Model Performance with Previous Studies

Comparison of the fitted gaussian plume model performance using CALPUFF version 5.8 with past CALPUFF evaluations from the 1998 EPA study (EPA, 1998a) using the Great Plains and Savannah River tracer study field experiments was mixed.

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For the Great Plains 100 km receptor arc, the current and previous CALPUFF model performance evaluations were generally consistent. In both studies, CALPUFF tended to overestimate the plume maximum concentrations and underestimate plume horizontal dispersion. The two studies showed considerably less agreement for the 600 km Great Plains receptor arc. The EPA (1998) study noted good agreement at the 600 km arc when the CALPUFF slug option was used, which is not a regulatory default option for long-range transport. The ENVIRON (2012) study reported a poor agreement using the fitted Gaussian plume model metrics when CALPUFF model results were compared to the SRL field campaign results. ENVIRON (2012) suggested that a Gaussian distribution may not be an appropriate assumption for long source-receptor distances and recommend that the fitted gaussian plume model performance metrics be replaced with statistical approaches more like the ATMES-II performance metrics in future model performance evaluations.

CALPUFF Model Performance Using CALMET versus MMIF

Mixed modeled-measured tracer concentration performance was exhibited depending on the field campaign considered and the meteorology methodology used in CALPUFF. In general, there was less variation in CALPUFF model results when MMIF was used compared to CALMET. The best performing scenario was when MMIF extracted MM5 36-km and 12-km meteorology and CALPUFF model results were compared to tracer results from the CAPTEX CTEX3 study.

Comparison of Model Performance of Long-Range Transport Dispersion Models

Several dispersion and photochemical grid models including CAMx, SCIPUFF, FLEXPART, HYSPLIT, CALPUFF, and CALGRID were compared to observations from several observational datasets (CTEX3, CTEX5, ETEX). When model results are compared to CTEX campaign data, CALPUFF model performance is generally within the range of calculated statistical performance metrics. CALPUFF model performance is weaker when compared to ETEX campaign data, likely because the field campaign extent (parts of 17 European countries) is much larger than a typical CALPUFF modeling domain.

3.5 A Protocol on Methods and Procedures to be Followed Has Been Established

A detailed PSD Modeling Protocol including a far-field cumulative Class I PSD increment analysis should be provided at the beginning of any PSD project. The

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Modeling Protocol should also include an overview of the meteorological dataset processing, and any WRF modeling on which it relies.

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4. CONCLUSIONS

This technical document provides evidence to support each requirement outlined in Section 3.2.2(e) of the EPA's Guideline on Air Quality Modeling (40 CFR 51 Appendix W). To demonstrate that CALPUFF has received sufficient scientific peer review, a summary of the scientific peer review literature leading to the original decision to list CALPUFF as an EPA-preferred model is provided, along with a general description of the decisions, policy, and guidance related to the designation. A theoretical review of Lagrangian puff modeling, as well as theoretical and technical summaries of CALPUFF, WRF, and MMIF, are provided to show that this modeling framework is suitable for a far-field cumulative Class I PSD increment on a theoretical basis. A description of the CALPUFF modeling system and its availability is presented to show that the CALPUFF databases are available and adequate. Lastly, a summary of CALPUFF model evaluations involving tracer studies is presented to demonstrate that the use of CALPUFF for far-field modeling applications is not inappropriately biased for regulatory applications.

This document supports a conclusion that CALPUFF v5.8.5 should be considered an appropriate alternative model for long-range transport dispersion applications, such as far-field cumulative Class I PSD increment analyses.

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Message

From: Meyer, Dan [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=06A1ECF8238B44338282FB618A40674C-MEYER, DAN]
Sent: 9/2/2022 9:24:18 PM
To: R10 Air Permits [R10_Air_Permits@epa.gov]
Subject: FW: AQ1539CPT01 Final Transmittal Letter - Alaska Gasline Development Corporation, Liquefaction Plant 07.07.22
Attachments: AQ1539CPT01 Final Trans Ltr 07.07.22.pdf; AQ1539CPT01 Final Permit 07.07.22.pdf; AQ1539CPT01 Final TAR 07.07.22.pdf; AQ1539CPT01 RTC 07.07.22.pdf

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Subject: AQ1539CPT01 Final Transmittal Letter - Alaska Gasline Development Corporation, Liquefaction Plant 07.07.22

All Recipients,

Please review or file the attached document(s) as required. Thank you.

Veronica Buness
Administrative Assistant I
Division of Air Quality
Department of Environmental Conservation
907-465-5112

DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY CONTROL CONSTRUCTION PERMIT

Construction Permit: AQ1539CPT01 **Final Date – July 7, 2022**

The Alaska Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Construction Permit AQ1539CPT01 to the Permittee listed below.

Permittee:	**Alaska Gasline Development Corporation** 3201 C Street, Suite 200 Anchorage, AK 99503
Stationary Source:	**Liquefaction Plant**
Location:	Nikiski, Alaska Latitude: 60.6655° North; Longitude: 151.3593° West
Project:	Construct Liquefaction Plant
Permit Contact:	Frank Richards (907) 330-6352 FRichards@agdc.us

This permit is classified under 18 AAC 50.306 as a Prevention of Significant Deterioration (PSD) major stationary source for oxides of nitrogen (NOx), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter (PM), particulate matter with an aerodynamic diameter not exceeding a nominal 10 micrometers (PM-10), particulate matter with an aerodynamic diameter not exceeding a nominal 2.5 micrometers (PM-2.5), volatile organic compounds (VOC), and greenhouse gases (GHGs). The project is also classified under 18 AAC 50.316 as a major source of Hazardous Air Pollutants (HAPs) for formaldehyde and ethylbenzene.

This permit satisfies the obligation of the Permittee to obtain a construction permit under 18 AAC 50. As required by AS 46.14.120(c), the Permittee shall comply with the terms and conditions of this permit.

for: James R. Plosay, Manager
Air Permits Program

\\JN-SVRFILE\groups\AQ\PERMITS\AIRFACS\Alaska Gasline Dev Corp (AK LNG Project)\Liquefaction Plant (1539)\Construction\CPT01\Final\AQ1539CPT01 Final Permit and TAR.docx

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Abbreviations and Acronyms

AAC.....Alaska Administrative Code
ADEC.....Alaska Department of Environmental Conservation
AAAQS.....Alaska Ambient Air Quality Standard(s)
AOS.....Air Online Services
AS.....Alaska Statutes
ASTM.....American Society for Testing and Materials
BACT.....best available control technology
CDX.....Central Data Exchange
CEDRI.....Compliance and Emissions Data Reporting Interface
C.F.R.....Code of Federal Regulations
CAA.....Clean Air Act
CO.....carbon monoxide
Department.....Alaska Department of Environmental Conservation
dscf.....dry standard cubic foot
EPA.....US Environmental Protection Agency
EU.....emissions unit
FEM.....Federal Equivalent Method
gr/dscf.....grain per dry standard cubic foot (1 pound = 7000 grains)
gph.....gallons per hour
GTP.....Gas Treatment Plant
HAPs.....hazardous air pollutants [as defined in AS 46.14.990]
HP.....High Pressure
kPa.....kiloPascals
LP.....Low Pressure
MACT.....maximum achievable control technology [as defined in 40 C.F.R. 63]
MMBtu/hr.....million British thermal units per hour
MMscf.....million standard cubic feet
MR&R.....monitoring, recordkeeping, and reporting
Mscf.....thousand standard cubic
NESHAPs.....National Emission Standards for Hazardous Air Pollutants [as contained in 40 C.F.R. 61 and 63]
NOx.....nitrogen oxides
NO_2.....nitrogen dioxide
NRE.....nonroad engine
NSPS.....New Source Performance Standards [as contained in 40 C.F.R. 60]
O & M.....operation and maintenance
O_2.....oxygen
PM-10.....particulate matter less than or equal to a nominal 10 microns in diameter
PM-2.5.....particulate matter less than or equal to a nominal 2.5 microns in diameter
ppm.....parts per million
ppmv, ppmvd.....parts per million by volume on a dry basis
psia.....pounds per square inch (absolute)
PSD.....prevention of significant deterioration
PTE.....potential to emit
QAPP.....Quality Assurance Project Plan
QA/QC.....Quality Assurance/Quality Control
SIC.....Standard Industrial Classification
SIP.....State Implementation Plan
SPC.....Standard Permit Condition or Standard Operating Permit Condition
SO_2.....sulfur dioxide
tpy.....tons per year
ULSD.....Ultra-Low Sulfur Diesel
VOC.....volatile organic compound [as defined in 40 C.F.R. 51.100(s)]
vol%.....volume percent
WHRU.....waste heat recovery unit
wt%.....weight percent
$wt\%S_{fuel}$.....weight percent of sulfur in fuel
$\mu g/m^3$.....micrograms per cubic meter

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Section 1 *Emissions Unit Inventory*

Emissions Unit (EU) Authorization. The Permittee is authorized to install and operate the EUs listed in Table 1 in accordance with the terms and conditions of this permit. The information in Table 1 is for identification purposes only, unless otherwise noted in the permit. The specific EU descriptions do not restrict the Permittee from replacing an EU identified in Table 1.

Table 1 – EU Inventory

EU #	EU Description	Fuel	Rating/Max Capacity
1	Simple Cycle Treated Gas Compressor Turbine (Train 1a)	Fuel Gas	1,113[1] MMBtu/hr
2	Simple Cycle Treated Gas Compressor Turbine (Train 1b)	Fuel Gas	1,113[1] MMBtu/hr
3	Simple Cycle Treated Gas Compressor Turbine (Train 2a)	Fuel Gas	1,113[1] MMBtu/hr
4	Simple Cycle Treated Gas Compressor Turbine (Train 2b)	Fuel Gas	1,113[1] MMBtu/hr
5	Simple Cycle Treated Gas Compressor Turbine (Train 3a)	Fuel Gas	1,113[1] MMBtu/hr
6	Simple Cycle Treated Gas Compressor Turbine (Train 3b)	Fuel Gas	1,113[1] MMBtu/hr
7	Combined Cycle Power Generation Combustion Turbine	Fuel Gas	384[1] MMBtu/hr
8	Combined Cycle Power Generation Combustion Turbine	Fuel Gas	384[1] MMBtu/hr
9	Combined Cycle Power Generation Combustion Turbine	Fuel Gas	384[1] MMBtu/hr
10	Combined Cycle Power Generation Combustion Turbine	Fuel Gas	384[1] MMBtu/hr
11	Emergency Firewater Pump RICE	ULSD	575 hp
12	Auxiliary Air Compressor RICE	ULSD	300 hp
13	Thermal Oxidizer	Fuel Gas/ Process Gas	6.0 MMBtu/hr
14	Dry Ground Flare #1	Fuel Gas/ Process Gas	55,000[2] Mscf/hr
15	Wet Ground Flare #1		13,000[3] Mscf/hr
16	Dry Ground Flare #2	Fuel Gas/ Process Gas	55,000[2] Mscf/hr
17	Wet Ground Flare #2		13,000[3] Mscf/hr
18	Dry Ground Flare #3	Fuel Gas/ Process Gas	55,000[2] Mscf/hr
19	Wet Ground Flare #3		13,000[3] Mscf/hr
20	Elevated Low Pressure Flare	Fuel Gas/ Process Gas	990[4] Mscf/hr
21	Gas Condensate Storage Tank	Stabilized NGLs	457,890 gallons
22	Off-Spec Gas Condensate Storage Tank	Stabilized NGLs	126,904 gallons
23	Gas Condensate Loading System	Stabilized NGLs	1,000 gallons
24	Diesel Storage Tank	ULSD	3,520 gallons
25	Air Compressor Diesel Tank	ULSD	342 gallons
26	Firewater Pump Diesel Tank	ULSD	342 gallons

Table Notes:

[1] The capacity listed for EUs 1 through 10 reflects the rating for each unit at the yearly average ambient temperature for the Liquefaction Plant of 40°F.

[2] EUs 14, 16, and 18 have the maximum relief event capacity listed in Table 1. The pilot, purge, and assist rate for these EUs is 6.4 thousand standard cubic feet per hour (Mscf/hr), per unit.

[3] EUs 15, 17, and 19 have the maximum relief event capacity listed in Table 1. The pilot, purge, and assist rate for these EUs is 2.1 Mscf/hr, per unit.

[4] The pilot, purge, and assist rate for low pressure flare is 19.0 Mscf/hr.

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1. The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement EU, including any applicable minor or construction permit requirements.

2. The Permittee shall commence[1] construction of the stationary source authorized under Construction Permit AQ1539CPT01 within 18 months of the issuance of the permit unless granted an extension in writing from the Department.

[1] Commence has the meaning given in 40 C.F.R. 52.21(b)(9).

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Section 2 *Fee Requirements*

3. **Fee Requirements.** The Permittee shall pay to the Department all assessed permit fees. Fee rates are set out in 18 AAC 50.400-420.

4. **Assessable Emissions**. The Permittee shall pay to the Department annual emission fees based on the stationary source's assessable emissions as determined by the Department under 18 AAC 50.410.[2] The assessable emission fee rate is set out in 18 AAC 50.410. The Department will assess fees per ton of each air pollutant that the stationary source emits or has the potential to emit in quantities 10 tons per year or greater. The quantity for which fees will be assessed is the lesser of:

   4.1 the stationary source's assessable potential to emit of 40,827 tpy; or

   4.2 the stationary source's projected annual rate of emissions that will occur from July 1 to the following June 30, based upon credible evidence of actual annual emissions emitted during the most recent calendar year or another 12 month period approved in writing by the Department, when demonstrated by the most representative of one or more of the following methods:

      a. an enforceable test method described in 18 AAC 50.220;

      b. material balance calculations;

      c. emission factors from EPA's publication AP-42, Vol. I, adopted by reference in 18 AAC 50.035;

      d. other methods and calculations approved by the Department, including appropriate vendor-provided emissions factors when sufficient documentation is provided.

5. **Assessable Emission Estimates.** Emission fees will be assessed as follows:

   5.1 no later than March 31 of each year, the Permittee may submit an estimate of the stationary source's assessable emissions via the Department's AOS System at http://dec.alaska.gov/applications/air/airtoolsweb using the Permittee Portal option and filling out the Emission Fee Estimate form. Alternatively, the report may be submitted by:

      a. Email under a cover letter using dec.aq.airreports@alaska.gov; or

      b. hard copy to the following address: ADEC Air Permits Program, ATTN: Assessable Emissions Estimate, 555 Cordova Street, Anchorage, Alaska 99501.

[2] If the stationary source has not commenced construction or operation on or before March 31st, submit a transmittal letter certified under 18 AAC 50.205 to the Department's Juneau office, in accordance with Condition 5.1, that identifies the source's assessable emissions for the previous fiscal year to be zero tons per year and provide estimates for when construction and operation will commence.

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5.2 The Permittee shall include with the assessable emissions report all of the assumptions and calculations used to estimate the assessable emissions in sufficient detail so the Department can verify the estimates.

5.3 If no estimate is submitted on or before March 31 of each year, emission fees for the next fiscal year will be based on the potential to emit set out in Condition 4.1.

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Section 3 *State Emission Standards*

6. **Visible Emissions for Industrial Process and Fuel-Burning Equipment.** The Permittee shall not cause or allow visible emissions (VE), excluding condensed water vapor, emitted from EUs 1 through 20 listed in Table 1, to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.

6.1 For EUs 11 and 12, perform an initial Method 9 observation within 60 days of initial startup up of each EU.

a. Record the date of initial startup of EUs 11 and 12.

b. Report the results of the Method 9 observations required by Condition 6.1 and the date of initial startup required by Condition 6.1a in the first operating report due after the observations were performed, as required under Condition 24.

6.2 For EUs 1 through 10 and 13, burn only fuel gas as fuel. Monitoring for these EUs shall consist of a statement in each operating report required under Condition 24 that each of these EUs fired only fuel gas as fuel. Report under Condition 23 if any fuel other than fuel gas is burned.

6.3 For EUs 14 through 20, perform an initial Method 9 observation during the initial daylight flare event.[3] If no event exceeds one hour then the Permittee shall observe the next daylight flare event.

a. Monitor the flare for visible emissions for 18 minutes during flare events using Method 9.

b. Record the following information for observed events:

(i) the flare(s) EU number;

(ii) results of the Method 9 observations;

(iii) reason(s) for flaring;

(iv) date, beginning and ending time of event; and

(v) volume of fuel gas and produced gas flared.

c. Monitoring of a flare event may be postponed for safety or weather reasons, or because a qualified observer is not available. If monitoring of a flare event is postponed for any of the reasons described in this condition, the Permittee shall include in the next operating report required by Condition 24 an explanation of the reason the event was not monitored.

d. Attach copies of the records required by Condition 6.3b in the first operating

[3] For purposes of this permit, a flare event is flaring of fuel gas and produced gas for greater than one hour as a result of scheduled release operations, i.e. maintenance. It does not include non-scheduled release operations, i.e. process upsets, emergency flaring, or de-minimis venting of gas incidental to normal operations.

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report due after the observations were performed, as required under Condition 24.

6.4 Report as excess emissions and permit deviation under Condition 23 whenever the opacity standard in Condition 6 is exceeded or if any of Conditions 6.1 through 6.3 are not met.

7. **Particulate Matter for Industrial Process and Fuel-Burning Equipment.** The Permittee shall not cause or allow particulate matter emitted from EUs 1 through 20 listed in Table 1, to exceed 0.05 grains per dry standard cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.

7.1 For EUs 11 and 12, obtain a certified manufacturer's guarantee that the EUs will comply with the particulate matter standard, within 60-days of startup; or

7.2 Demonstrate compliance with the PM standard by complying with Condition 6.1.

8. **Sulfur Compound Emissions.** The Permittee shall not cause or allow sulfur compound emissions, expressed as SO_2, from EUs 1 through 20 listed in Table 1 to exceed 500 parts per million (ppm) averaged over three hours.

8.1 For EUs 1 through 10 and 13 through 20, demonstrate compliance with the SO_2 standard by complying with Condition 11.2.

8.2 For EUs 11 and 12, demonstrate compliance with the SO_2 standard by complying with Condition 11.1.

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Section 4 *Ambient Air Quality Protection Requirements*

9. The Permittee shall construct and operate the stationary source as described below in order to protect all averaging periods of the NO_2, CO, PM-10, PM-2.5, and SO_2 AAAQS, and the NO_2, PM-10 and PM-2.5 Class II increments:

9.1 **Stack Configuration for Temporary Construction Engines.** Construct and maintain vertical, uncapped exhaust stacks for all reciprocating engines used to provide electrical power to the temporary Liquefaction Plant construction camps. This condition does not preclude the use of flapper-style rain covers, or other similar designs, that do not hinder the vertical momentum of the exhaust plume.

a. Include in each operating report required by Condition 24:

(i) A statement that the temporary camp engine exhaust stacks comply with Condition 9.1, or

(ii) A statement that no temporary camp engines were operated during the reporting period.

b. Report as described in Condition 23 if a requirement under Condition 9.1 was not met.

9.2 **Stack Configuration for Engines.** Construct and maintain vertical, uncapped exhaust stacks for EUs 11 and 12. This condition does not preclude the use of flapper-style rain covers, or other similar designs, that do not hinder the vertical momentum of the exhaust plume.

a. Include in the first operating report required by Condition 24 that would be due after the installation of an EU listed in Condition 9.2, a statement that the exhaust stack for that EU complies with Condition 9.2.

b. Report as described in Condition 23 if a requirement under Condition 9.2 was not met.

9.3 **Stack Height Requirements.** Construct and maintain the exhaust/flare stack heights, as applicable, for the EUs listed in Table 2 so that the height above the facility base elevation equals or exceeds the minimum height listed for that EU.

Table 2: Minimum Stack Height Requirements

EU	Description	Min. Height (m)
1 - 6	Treated Gas Compressor Turbines	64.0
7 – 10	Power Generation Turbines	45.7
20	Elevated Low Pressure Flares	63.4

a. Provide as-built drawings and photographs of each exhaust/flare stack listed in Table 2 in the first operating report required by Condition 24 that would be due after installation of the given EU.

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b. Report as described in Condition 23 if a requirement under Condition 9.3 was not met.

10. **Fugitive Particulate Matter Control Requirements.** The Permittee shall protect the 24-hour PM-10 AAAQS, the 24-hour PM-2.5 AAAQS, and the annual PM-2.5 AAAQS while constructing the stationary source by complying with Conditions 10.1 and 10.2 below.

10.1 **Fugitive Dust Control.** The Permittee shall limit fugitive dust emissions within the Liquefaction Plant project area by applying water/chemical suppressants to the dust emitting surfaces, or by reducing the dust-generating activity, as needed.

Monitor, record, and report as follows:

a. Except as allowed under Condition 10.1b, perform a daily inspection of the active construction areas to determine whether abatement is needed. Require abatement whenever a visible plume of dust has an estimated opacity that exceeds 20 percent at 300 feet or more from the source.

b. The daily inspections required under Condition 10.1a may be suspended on days with measurable precipitation, or on days with no dust-generating construction activities.

c. Record the location, observed activity, and fugitive dust observations of each inspection in a daily log. Record whether abatement was required, and if so, the action that was taken. Note whenever the daily inspections were suspended, as allowed under Condition 10.1b, and if so, why.

d. Record all fugitive dust complaints received by the Permittee, or by the Department and conveyed to the Permittee, utilizing the complaint form in Section 10. Record how the complaint was addressed/resolved.

e. Provide a copy of all fugitive dust complaints recorded under Condition 10.1d to the Department within 30 days of receiving the complaint.

f. Report any abatement actions performed under Condition 10.1 in the operating reports required by Condition 24.

g. Report as described in Condition 23 if a requirement under Condition 10.1 was not met.

10.2 **Ambient Air Monitoring**. The Permittee shall establish ambient PM-10 and PM-2.5 monitoring during the construction phase as follows:

a. At least 180 days prior to commencing construction, submit for Department approval a scaled site map(s) that identifies the proposed locations of one or more downwind PM-10 monitoring site, one or more downwind PM-2.5 monitoring site, and one or more upwind PM-10 and PM-2.5 monitoring sites.[4] Site the monitoring stations in areas that would likely experience the maximum

[4] Provide a copy of the monitoring locations proposed under Condition 10.2a to the Permit Intake Clerk in the Department's Anchorage office at 555 Cordova Street, Anchorage, Alaska 99501.

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construction-related 24-hour PM-10 and 24-hour PM-2.5 impacts from the Liquefaction Plant project area. Include a written narrative that documents the reasons for selecting the proposed monitoring sites.

b. Within 60 days of the Department's approval of the monitoring locations, submit for Department approval a QAPP for the PM-10/PM-2.5 monitoring effort.[5] The QAPP shall describe the procedures that the Permittee intends to use in order to:

(i) Collect continuous data using FEM continuous monitors;

(ii) Collect data that complies with 18 AAC 50.215(a);

(iii) Obtain data that meet the PSD program QA/QC requirements, including a data capture rate of 80 percent per quarter; and

(iv) Comply with Conditions 10.2c through 10.2e.

c. The Permittee shall initiate their monitoring program prior to beginning onsite construction. Once initiated, monitoring shall continue to occur year-round, throughout the Liquefaction Plant construction phase.

(i) The Permittee may temporarily suspend the monitoring program for a designated period, with written Department approval, during a long-term suspension of all fugitive dust generating construction activities.

(ii) The Permittee may permanently end the monitoring program, with written Department approval, once they have demonstrated to the Department's satisfaction that the fugitive dust generating construction activities have been completed, or upon commissioning[6] of EUs 1 through 20.

d. The Permittee shall establish a manual or automated system that continuously reviews the PM-10 and PM-2.5 monitoring data. Upload the hourly PM-10 and PM-2.5 concentrations to a publicly accessible database daily. Promptly take the following actions during elevated readings:

(i) If the measured PM-10 concentration exceeds 250 $\mu g/m^3$ but remains below 500 $\mu g/m^3$ during a 1-hour averaging period, or exceeds 75 $\mu g/m^3$ but remains below 100 $\mu g/m^3$ during a 24-hour averaging period, the permittee shall:

(A) Determine what emission activities are likely causing these elevated concentrations;

[5] Provide a copy of the QAPP proposed under Condition 10.2b to the Permit Intake Clerk in the Department's Anchorage office.

[6] For the purpose of this permit, commissioning of EUs 1 through 20 includes the initial mechanical acceptance of process equipment and electric generating equipment, for a period of time not to exceed 90 days from initial startup of the first EU.

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(B) Monitor the weather forecast, and actual wind speed and direction data from the Kenai Municipal Airport, in order to predict the likely need for reducing on-site PM-10 emissions; and

(C) Take the preparatory actions needed to promptly reduce on-site fugitive dust emissions, if such action is subsequently required under Condition 10.2d(ii).

(ii) If the measured PM-10 concentration exceeds 500 $\mu g/m^3$ during a 1-hour averaging period, or 100 $\mu g/m^3$ during a 24-hour averaging period, the Permittee shall take one or more of the following actions as needed to reduce the measured concentrations or to document the off-site source of the elevated concentrations:

(A) Inspect the immediate vicinity of the monitor(s) for possible causes of the elevated readings, and if warranted, take appropriate abatement action;

(B) Apply focused chemical and/or water treatment or other corrective actions in the active construction areas that are potentially contributing to the elevated PM-10 concentrations;

(C) If necessary, temporarily realign or suspend the construction activities that are likely causing or substantially contributing to these measured concentrations; and/or

(D) If the elevated concentrations appear to be due to natural events, such as wildfire, document the basis for reaching that conclusion, and note whether fugitive dust emissions are being properly controlled.

(iii) If the measured PM-2.5 concentration exceeds 60 $\mu g/m^3$ but remains below 120 $\mu g/m^3$ during a 1-hour averaging period, or exceeds 15 $\mu g/m^3$ but remains below 25 $\mu g/m^3$ during a 24-hour averaging period, the permittee shall:

(A) Determine what emission activities are likely causing these elevated concentrations;

(B) Monitor the weather forecast, and actual wind speed and direction data from the Kenai Municipal Airport, in order to predict the likely need for reducing on-site PM-2.5 emissions; and

(C) Take the preparatory actions needed to promptly reduce on-site fugitive dust emissions, if such action is subsequently required under Condition 10.2d(iii).

(iv) If the measured PM-2.5 concentration exceeds 120 $\mu g/m^3$ during a 1-hour averaging period, or 25 $\mu g/m^3$ during a 24-hour averaging period, the Permittee shall take one or more of the following actions as needed

to reduce the measured concentrations or to document the off-site source of the elevated concentrations:

(A) Inspect the immediate vicinity of the monitor(s) for possible causes of the elevated readings, and if warranted, take appropriate abatement action;

(B) Apply focused chemical and/or water treatment or other corrective actions in the active construction areas that are potentially contributing to the elevated PM-2.5 concentrations;

(C) If necessary, temporarily realign or suspend the construction activities that are likely causing or substantially contributing to these measured concentrations; and/or

(D) If the elevated concentrations appear to be due to natural events, such as wildfire, document the basis for reaching that conclusion, and note whether fugitive dust emissions are being properly controlled.

(v) Notify the Department in accordance with Condition 20 within 24-hours of any actions taken under Condition 10.2d(ii) or if any:

(A) 24-hour average PM-10 concentration exceeds 150 µg/m3,

(B) 24-hour average PM-2.5 concentration exceeds 35 µg/m3, or

(C) Annual average PM-2.5 concentration exceeds 12 µg/m3.

(vi) Report in the operating report required under Condition 24, any actions taken under Condition 10.2d(i), 10.2d(ii), 10.2d(iii), or 10.2d(iv), including mitigative measures taken.

e. Submit annual monitoring reports for Department review and approval as follows:

(i) The monitoring reports shall be submitted no later than 60 days after a block 12-month monitoring period ends;

(ii) Provide a copy of the reports specified in Condition 10.2e to the Permit Intake Clerk in the Department's Anchorage office.

f. Report as described in Condition 23 whenever a measured concentration of PM-10 or PM-2.5 exceed the values listed in Condition 10.2d(v)(A) through 10.2d(v)(C), or if a requirement under Condition 10.2 is not met.

11. **Fuel Sulfur Limits.** To protect the one-hour, three-hour, 24-hour, and annual SO_2 AAAQS; and the three-hour, 24-hour, and annual SO_2 Class II increments, the Permittee shall:

11.1 Combust only diesel fuel that meets the ULSD specifications (i.e., less than 0.0015 percent sulfur by weight) in EUs 11 and 12.

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Monitor, record, and report as follows:

a. Obtain and keep certified receipts from fuel suppliers that confirms that all diesel fuel combusted in EUs 11 and 12 meets the specifications of ULSD.

b. Report in each operating report required by Condition 24, a statement indicating whether all fuel combusted in EUs 11 and 12 during the reporting period was ULSD.

c. Report as described in Condition 23 if:

(i) fuel combusted in EUs 11 and 12 exceeds the ULSD specifications; or

(ii) Conditions 11.1a or 11.1b are not met.

11.2 Limit the total sulfur content of the fuel gas fired in EUs 1 through 10 and 13 through 20 to no more than 16 ppmv.

Monitor, record, and report as follows:

a. Analyze a representative sample of the fuel burned by EUs 1 through 10 and 13 through 20, at least monthly to determine the sulfur content using either ASTM D4084, D5504, D4810, D4913, D6228 or GPA Standard 2377, or a listed method approved in 18 AAC 50.035(b)-(c) or 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1); or

b. A current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel does not exceed the limit in Condition 11.2.

c. Keep records of the sulfur content analysis required under Condition 11.2a, or records specifying the maximum total sulfur content of the fuel required under Condition 11.2b.

d. Include copies of the records required by Condition 11.2c with the operating report required by Condition 24 for the period covered by the report.

e. Report as excess emissions in accordance with Condition 23, whenever the sulfur content of the fuel gas fired in EUs 1 through 10 and 13 through 20, exceed 16 ppmv.

12. To protect the one-hour and annual NO_2 AAAQS, the one-hour and annual SO_2 AAAQS, the annual PM-2.5 AAAQS, the annual NO_2 Class II increment, the annual SO_2 Class II increment, the annual PM-10 Class II increment, and the annual PM-2.5 Class II increment, the Permittee shall limit the operation of EUs 11 and 12 to no more than 500 hours each, in any 12 consecutive month period. Monitor, record, and report in accordance with Conditions 15.2b(i) through 15.2b(iv). Report as described in Condition 23 if any of EUs 11 or 12 exceed 500 hours in any 12 consecutive month period, or if a requirement under Condition 15.2b is not met.

Section 5 *Best Available Control Technology*

13. **Compressor Turbines BACT Emission Limits:** Limit the emissions from the simple cycle gas compressor turbines EUs 1 through 6 as specified in Table 3, except as provided in Condition 13.1:

Table 3: Compressor Turbines (EUs 1 through 6) – BACT Limits

Pollutant	BACT Control	BACT Emission Limits
NOx	SCR + Dry Low NOx Good Combustion Practices	2 ppmvd at 15% O_2
CO	Oxidation Catalyst Good Combustion Practices	5 ppmvd at 15% O_2
PM, PM-10, and PM-2.5	Clean Fuel (Natural Gas) Good Combustion Practices	0.0070 lb/MMBtu[1]; 10% opacity averaged over any six consecutive minutes
SO_2	Clean Fuel (Natural Gas) Good Combustion Practices	Burn Gas with total Sulfur Content of ≤ 16 ppmv
VOC	Oxidation Catalyst Good Combustion Practices	2 ppmvd at 15% O_2
GHG	Clean Fuel (Natural Gas) Good Combustion Practices	117.1 lb/MMBtu[1]

[1.] Emission limits are based on heat input in MMBtu/hr.

13.1 For EUs 1 through 6, the Permittee shall:

a. Limit the number of hours EUs 1 through 6 operate without the selective catalytic reduction (SCR) and/or oxidation catalyst pollution control systems in full operation[7] to no more than 40 hours each per consecutive 12-month period. During these periods of operation when the pollution control systems are not in full operation, operate EUs 1 through 6 according to manufacturer's specifications and good combustion practices.

(i) Calculate and record monthly, the number of hours each of EUs 1 through 6 operated without the pollution control systems in full operation for the previous month.

(ii) Calculate and record monthly, the number of hours each of EUs 1 through 6 operated without the pollution control systems in full operation for the previous 12 consecutive month period.

(iii) Report in the operating report required in Condition 24 for each month covered in the operating report, the total hours each of EUs 1 through 6

[7] The 40 hours of allotted time for pollution control system bypass are necessary for periods of startup and shutdown when the exhaust is not up to the manufacturer's recommended catalyst temperatures.

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operated without the pollution control systems in full operation as recorded in Condition 13.1a(ii).

b. Install, operate, and maintain dry low NOx (DLN) combustors emissions controls on EUs 1 through 6, according to the manufacturer's specifications, at all times the units are operating.

c. Perform regular maintenance according to the manufacturer's or the operator's maintenance procedures.

d. Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

e. Keep a copy of either the manufacturer's or the operator's maintenance procedures.

13.2 To show compliance with the NOx emission limit set out in , the Permittee shall:

a. Submit to the Department vendor verification that the simple cycle turbines will comply with the NOx limit in Table 3 at least 60 days before startup of any of EUs 1 through 6.

b. Conduct an initial source test in accordance with Section 8 on at least two of EUs 1 through 6,[8] within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after initial startup of the turbine, to demonstrate initial compliance with the NOx limit listed in Table 3 as follows:

(i) Conduct the source test for at least three loads representative of the normal operating range of the EU. One load must be within plus or minus 25 percent of 100 percent of peak load. The Permittee may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice.

(ii) Use the applicable test method set out in 40 C.F.R. 60, Appendix A. Source test downstream of the SCR and catalytic oxidation control systems.

(iii) Each source test shall consist of at least three 20-minute or longer valid test runs at each load. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of lb/MMBtu as well as the appropriate units for the corresponding pollutant listed in Table 3.

(iv) During each test run, measure the inlet air temperature and pressure drop across the oxidation catalyst.

(v) The Permittee shall report the results of the source test to the Department in accordance with Condition 39.

[8] 40 C.F.R. 60 Subpart KKKK requires initial and annual performance testing on each turbine subject to the new source performance standards of Subpart KKKK unless a waiver is granted by EPA.

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c. Install, operate, and maintain SCR on EUs 1 through 6 according to the manufacture's specifications, at all times the units are operating, except during the allowable hours as specified in Condition 13.1a. For each SCR system, install and operate the SCR units as follows:

(i) Conduct an initial source test in accordance with Section 8, on at least two of EUs 1 through 6 within 180 days from the first of EUs 1 through 6 beginning operation.

(ii) Conduct the source test at the maximum achievable load of the EU while the exhaust from the turbine is routed through the SCR system (representative of the normal operation scenario).

(iii) Report the results of the source test to the Department in accordance with Condition 39, including the information from Condition 13.2c(v)(D).

(iv) Install, operate, and maintain temperature sensing devices to monitor the inlet temperature of each installed SCR control system.

(A) Monitor turbine exhaust temperature at the inlet to each SCR unit at least once per hour during all periods of operation. Record for each calendar day the minimum and maximum inlet gas temperature of each SCR unit. Data capture and recording may be electronic.

(B) Report the minimum and maximum daily inlet gas temperature of each SCR control for each calendar month in the operating report required by Condition 24.

(v) Install, operate, and maintain a flow meter for measuring ammonia injection flowrate.

(A) Monitor and record the ammonia injection flowrate in gallons per hour at least once per hour during all periods of operation, excluding engine startup when the SCR is not fully operational. Record for each calendar day the minimum and maximum ammonia injection flowrate for each SCR unit. Data capture and recording may be electronic.

(B) Report the minimum and maximum daily ammonia injection flowrate for each SCR control unit for each calendar month in the operating report required by Condition 24.

(C) Limit emissions of ammonia slip downstream of the SCR to no greater than 10 ppmv as measured at maximum achievable load in accordance with Condition 13.2c(v)(D).

(D) During the source test required by Condition 13.2c(i), measure the ammonia slip using the U.S. EPA Method 320 or ASTM D6348 for Fourier Transform Infrared Spectroscopy (FTIR), CTM-027, or

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Bay Area Source Test Procedure ST-1B, as applicable. The test shall be completed at maximum achievable load. The highest ammonia injection rate setting (gallons per hour) of the three runs shall become the maximum ammonia injection rate for the SCR equipped turbines.

13.3 To show compliance with the CO and VOC emission limits set out in Table 3, the Permittee shall:

a. Submit to the Department vendor verification that the catalytic oxidation control system will comply with the CO and VOC limits established in Table 3 at least 60 days before startup of any of EUs 1 through 6.

b. Conduct an initial source test in accordance with Section 8 on two of EUs 1 through 6, within 180 days from the first of EUs 1 through 6 beginning operation, to demonstrate initial compliance with the CO and VOC limits listed in Table 3 as follows:

(i) Conduct the source test for at least three loads representative of the normal operating range of the EU.

(ii) Use the applicable test method set out in 40 C.F.R. 60, Appendix A. Source test downstream of the catalytic oxidation control system.

(iii) Each source test shall consist of at least three 20-minute or longer valid test runs at each load. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of lb/MMBtu as well as the appropriate units for the corresponding pollutant listed in Table 3.

(iv) During each test run, measure the inlet air temperature and pressure drop across the oxidation catalyst.

(v) The Permittee shall report the results of the source test to the Department in accordance with Condition 39.

c. Install, operate, and maintain an oxidation catalyst pollution control system on EUs 1 through 6 according to the manufacture's specifications, at all times the units are operating, except during the allowable hours as specified in Condition 13.1a. Operate each oxidation catalyst pollution control system as follows:

(i) Install temperature sensing devices to monitor the inlet air temperature of each installed oxidation catalyst.

(A) Monitor exhaust temperature at the inlet to each oxidation catalyst unit at least once per hour during all periods of operation. Record for each calendar day the minimum and maximum inlet gas temperature of each oxidation catalyst unit. Data capture and recording may be electronic.

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(B) Report the minimum and maximum daily inlet gas temperature of each oxidation catalyst unit for each calendar month in the operating report required by Condition 24.

(ii) Install gauges before and after the oxidation catalyst controls to monitor the pressure drop across each installed oxidation catalyst unit.

(A) Maintain the oxidation catalyst such that the pressure drop across each oxidation unit is within the acceptable range identified in the manufacturer's specifications, or within the range determined by the most recent source tests under Conditions 13.2b(iv), 13.3b(iv), and 13.4b(iv).

(B) If the pressure drop exceeds the acceptable differential identified in the manufacturer's specifications, the oxidation catalyst unit shall be inspected, cleaned, or replaced, as necessary.

13.4 To show compliance with the PM, PM-10, and PM-2.5 emission limits set out in Table 3, the Permittee shall:

a. Submit to the Department, a certified manufacturer's guarantee demonstrating that EUs 1 through 6 will comply with the emission limits in Table 3 at least 60 days before startup of any of EUs 1 through 6; or

b. Conduct an initial source test in accordance with Section 8, on two of EUs 1 through 6 within 180 days from the first of EUs 1 through 6 beginning operation to demonstrate initial compliance with the PM, PM-10, and PM-2.5 limits listed in Table 3 as follows:

(i) Conduct the source test for at least three loads representative of the normal operating range of the EU.

(ii) Use the applicable test method set out in 40 C.F.R. 60, Appendix A. Source test downstream of the catalytic oxidation control system.

(iii) Each source test shall consist of at least three 20-minute or longer valid test runs at each load. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of lb/MMBtu.

(iv) During each test run, measure the inlet air temperature and pressure drop across the oxidation catalyst.

(v) The Permittee shall report the results of the source test to the Department in accordance with Condition 39.

c. Except as allowed by Condition 13.4c(ii), for EUs 1 through 6, conduct annual visible emission observations, the first to be completed within 180 days from the first of EUs 1 through 6 beginning operation to demonstrate compliance with the opacity limit in Table 3. The observations shall be conducted as specified by 40 C.F.R. 60, Appendix A-4, Method 9, adopted by reference in

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18 AAC 50.040(a), for 18 minutes to obtain 72 consecutive 15-second opacity observations.

(i) Except as allowed by Condition 13.4c(ii), conduct subsequent visible emission observations within twelve months after the preceding observation.

(ii) For an emission unit with intermittent operations, the required visual observations may be completed during the next scheduled operation immediately following the deadline stated in Condition 13.4c or 13.4c(i).

(iii) Record results using the Visible Emissions Observation Form found in Attachment 1 and report the results of all visible emissions observations in the operating report as required under Condition 24.

13.5 To show compliance with the SO_2 emission limit set out in Table 3, the Permittee shall:

a. Monitor, record, and report in accordance with Condition 11.2.

b. Maintain good combustion practices at all times the units are in operation.

13.6 To show compliance with the GHG emission limit set out in Table 3, the Permittee shall:

a. Perform regular maintenance according to the manufacturer's or the operator's maintenance procedures;

b. Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format; and

c. Keep a copy of either the manufacturer's or the operator's maintenance procedures.

13.7 Report as described in Condition 23 whenever:

a. any of the emission rates determined by the source tests required by Conditions 13.2 through 13.4 exceed the limits in Table 3;

b. a six consecutive minute average opacity reading is above the limit in Table 3;

c. the inlet gas temperature of an SCR unit recorded in Condition 13.2c(iv)(A) is outside the acceptable range identified in the manufacturer's specifications. The report should include any corrective actions taken;

d. the ammonia injection flowrate is higher than the maximum ammonia injection rate identified in Condition 13.2c(v)(D). The report should include any corrective actions taken;

e. the inlet gas temperature of an oxidation catalyst unit is outside the acceptable range identified in the manufacturer's specifications, or outside the range

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determined by the most recent source tests under Conditions 13.2b(iv), 13.3b(iv), and 13.4b(iv);

f. the pressure drop across an oxidation catalyst unit is outside the acceptable range identified in the manufacturer's specifications, or outside the range determined by the most recent source tests under Conditions 13.2b(iv), 13.3b(iv), and 13.4b(iv); or

g. Conditions 13.1 through 13.6 are not met.

14. **Power Generation Turbines BACT Emission Limits:** Limit the emissions from the combined cycle power generation turbines EUs 7 through 10 as specified in Table 4, except as provided in Condition 14.1:

Table 4: Power Generation Turbines (EUs 7 through 10) – BACT Limits

Pollutant	BACT Control	BACT Emission Limits
NOx	SCR + Dry Low NOx Good Combustion Practices	2 ppmvd at 15% O_2
CO	Oxidation Catalyst Good Combustion Practices	2 ppmvd at 15% O_2
PM, PM-10, and PM-2.5	Clean Fuel (Natural Gas) Good Combustion Practices	0.0070 lb/MMBtu[1]; 10% opacity averaged over any six consecutive minutes
SO_2	Clean Fuel (Natural Gas) Good Combustion Practices	Burn Gas with total Sulfur Content of ≤ 16 ppmv
VOC	Oxidation Catalyst Good Combustion Practices	2 ppmvd at 15% O_2
GHG	Clean Fuel (Natural Gas) Good Combustion Practices	117.1 lb/MMBtu[1]

[1.] Emission limits are based on heat input in MMBtu/hr.

14.1 For EUs 7 through 10, the Permittee shall:

a. Limit the number of hours EUs 7 through 10 operate without the SCR and/or oxidation catalyst pollution control systems in full operation[7] to no more than 40 hours each per consecutive 12-month period. During these periods of operation when the pollution control systems are not in full operation, operate EUs 7 through 10 according to manufacturer's specifications and good combustion practices.

(i) Calculate and record monthly, the number of hours each of EUs 7 through 10 operated without the pollution control systems in full operation for the previous month.

(ii) Calculate and record monthly, the number of hours each of EUs 7 through 10 operated without the pollution control systems in full operation for the previous 12 consecutive month period.

(iii) Report in the operating report required in Condition 24 for each month covered in the operating report, the total hours each of EUs 7 through 10 operated without the pollution control systems in full operation as recorded in Condition 14.1a(ii).

b. Install, operate, and maintain DLN combustors on EUs 7 through 10, according to the manufacturer's specifications, at all times the units are operating.

c. Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

d. Keep a copy of either the manufacturer's or the operator's maintenance procedures.

14.2 To show compliance with the NOx emission limit set out in Table 4, the Permittee shall:

a. Submit to the Department vendor verification that the combined cycle turbines will comply with the NOx limit in Table 4 at least 60 days before startup of any of EUs 7 through 10.

b. Conduct an initial source test in accordance with Section 8 on at least two of EUs 7 through 10,[8] within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after initial startup of the turbine, to demonstrate initial compliance with the NOx limit listed in Table 4 as follows:

(i) Conduct the source test for at least three loads representative of the normal operating range of the EU. One load must be within plus or minus 25 percent of 100 percent of peak load. The Permittee may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice.

(ii) Use the applicable test method set out in 40 C.F.R. 60, Appendix A. Source test downstream of the SCR and catalytic oxidation control systems.

(iii) Each source test shall consist of at least three 20-minute or longer valid test runs at each load. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of lb/MMBtu as well as the appropriate units for the corresponding pollutant listed in Table 4.

(iv) During each test run, measure the inlet air temperature and pressure drop across the oxidation catalyst.

(v) The Permittee shall report the results of the source test to the Department in accordance with Condition 39.

c. Install, operate, and maintain SCR on EUs 7 through 10 according to the manufacture's specifications, at all times the units are operating, except during

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the allowable hours as specified in Condition 14.1a. For each SCR system, install and operate the SCR units as follows:

(i) Conduct an initial source test in accordance with Section 8, on at least two of EUs 7 through 10 within 180 days from the first of EUs 7 through 10 beginning operation.

(ii) Conduct the source test at the maximum achievable load of the EU while the exhaust from the turbine is routed through the SCR system (representative of the normal operation scenario).

(iii) Report the results of the source test to the Department in accordance with Condition 39, including the information from Condition 14.2c(v)(D).

(iv) Install, operate, and maintain temperature sensing devices to monitor the inlet temperature of each installed SCR control system.

(A) Monitor turbine exhaust temperature at the inlet to each SCR unit at least once per hour during all periods of operation. Record for each calendar day the minimum and maximum inlet gas temperature of each SCR unit. Data capture and recording may be electronic.

(B) Report the minimum and maximum daily inlet gas temperature of each SCR control for each calendar month in the operating report required by Condition 24.

(v) Install, operate, and maintain a flow meter for measuring ammonia injection flowrate.

(A) Monitor and record the ammonia injection flowrate in gallons per hour at least once per hour during all periods of operation, excluding engine startup when the SCR is not fully operational. Record for each calendar day the minimum and maximum ammonia injection flowrate for each SCR unit. Data capture and recording may be electronic.

(B) Report the minimum and maximum daily ammonia injection flowrate for each SCR control unit for each calendar month in the operating report required by Condition 24.

(C) Limit emissions of ammonia slip downstream of the SCR to no greater than 10 ppmv as measured at maximum achievable load in accordance with Condition 14.2c(v)(D).

(D) During the source test required by Condition 14.2c(i), measure the ammonia slip using the U.S. EPA Method 320 or ASTM D6348 for Fourier Transform Infrared Spectroscopy (FTIR), CTM-027, or Bay Area Source Test Procedure ST-1B, as applicable. The test shall be completed at maximum achievable load. The highest

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ammonia injection rate setting (gallons per hour) of the three runs shall become the maximum ammonia injection rate for the SCR equipped turbines.

14.3 To show compliance with the CO and VOC emission limits set out in Table 4, the Permittee shall:

a. Submit to the Department vendor verification that the catalytic oxidation control system will comply with the CO and VOC limits established in Table 4 at least 60 days before startup of any of EUs 7 through 10.

b. Conduct an initial source test in accordance with Section 8 on two of EUs 7 through 10, within 180 days from the first of EUs 7 through 10 beginning operation, to demonstrate initial compliance with the CO and VOC limits listed in Table 4 as follows:

(i) Conduct the source test for at least three loads representative of the normal operating range of the EU.

(ii) Use the applicable test method set out in 40 C.F.R. 60, Appendix A. Source test downstream of the catalytic oxidation control system.

(iii) Each source test shall consist of at least three 20-minute or longer valid test runs at each load. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of lb/MMBtu as well as the appropriate units for the corresponding pollutant listed in Table 4.

(iv) During each test run, measure the inlet air temperature and pressure drop across the oxidation catalyst.

(v) The Permittee shall report the results of the source test to the Department in accordance with Condition 39.

c. Install, operate, and maintain an oxidation catalyst pollution control system on EUs 7 through 10 according to the manufacture's specifications, at all times the units are operating, except during the allowable hours as specified in Condition 14.1a. Operate each oxidation catalyst pollution control system as follows:

(i) Install temperature sensing devices to monitor the inlet air temperature of each installed oxidation catalyst.

(A) Monitor exhaust temperature at the inlet to each oxidation catalyst unit at least once per hour during all periods of operation. Record for each calendar day the minimum and maximum inlet gas temperature of each oxidation catalyst unit. Data capture and recording may be electronic.

(B) Report the minimum and maximum daily inlet gas temperature of each oxidation catalyst unit for each calendar month in the operating report required by Condition 24.

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(ii) Install gauges before and after the oxidation catalyst controls to monitor the pressure drop across each installed oxidation catalyst unit.

(A) Maintain the oxidation catalyst such that the pressure drop across each oxidation unit is within the acceptable range identified in the manufacturer's specifications, or within the range determined by the most recent source tests under Conditions 14.2b(iv), 14.3b(iv), and 14.4b(iv).

(B) If the pressure drop exceeds the acceptable differential identified in the manufacturer's specifications, the oxidation catalyst unit shall be inspected, cleaned, or replaced, as necessary.

14.4 To show compliance with the PM, PM-10, and PM-2.5 emission limits set out in Table 4, the Permittee shall:

a. Submit to the Department, a certified manufacturer's guarantee demonstrating that EUs 7 through 10 will comply with the emission limits in Table 4 at least 60 days before startup of any of EUs 7 through 10; or

b. Conduct an initial source test in accordance with Section 8, on two of EUs 7 through 10 within 180 days from the first of EUs 7 through 10 beginning operation to demonstrate initial compliance with the PM, PM-10, and PM-2.5 limits listed in Table 4 as follows:

(i) Conduct the source test for at least three loads representative of the normal operating range of the EU.

(ii) Use the applicable test method set out in 40 C.F.R. 60, Appendix A. Source test downstream of the catalytic oxidation control system.

(iii) Each source test shall consist of at least three 20-minute or longer valid test runs at each load. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of lb/MMBtu heat input.

(iv) During each test run, measure the inlet air temperature and pressure drop across the oxidation catalyst.

(v) The Permittee shall report the results of the source test to the Department in accordance with Condition 39.

c. Except, as allowed by Condition 14.4c(ii), for EUs 7 through 10, conduct annual visible emission observations, the first to be completed within 180 days from the first of EUs 7 through 10 beginning operation to demonstrate compliance with the opacity limit in Table 4. The observations shall be conducted as specified by 40 C.F.R. 60, Appendix A-4, Method 9, adopted by reference in 18 AAC 50.040(a), for 18 minutes to obtain 72 consecutive 15-second opacity observations.

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(i) Except as allowed by Condition 14.4c(ii), conduct subsequent visible emission observations within twelve months after the preceding observation.

(ii) For an emission unit with intermittent operations, the required visual observations may be completed during the next scheduled operation immediately following the deadline stated in Condition 14.4c or 14.4c(i).

(iii) Record results using the Visible Emissions Observation Form found in Attachment 1 and report the results of all visible emissions observations in the operating report as required under Condition 24.

14.5 To show compliance with the SO_2 emission limit set out in Table 4, the Permittee shall:

a. Monitor, record, and report in accordance with Condition 11.2.

b. Maintain good combustion practices at all times the units are in operation.

14.6 To show compliance with the GHG emission limit set out in Table 4, the Permittee shall:

a. Perform regular maintenance according to the manufacturer's or the operator's maintenance procedures;

b. Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format; and

c. Keep a copy of either the manufacturer's or the operator's maintenance procedures.

14.7 Report as described in Condition 23 if:

a. any of the emission rates determined by the source tests required by Conditions 14.2 through 14.4 exceed the limits in Table 4;

b. a six consecutive minute average opacity reading is above the limit in Table 4;

c. the inlet gas temperature of an SCR unit recorded in Condition 14.2c(iv)(A) is outside the acceptable range identified in the manufacturer's specifications. The report should include any corrective actions taken;

d. The ammonia injection flowrate is higher than the maximum ammonia injection rate identified in Condition 14.2c(v)(D). The report should include any corrective actions taken;

e. the inlet gas temperature of an oxidation catalyst unit is outside the acceptable range identified in the manufacturer's specifications, or outside the range determined by the most recent source tests under Conditions 14.2b(iv), 14.3b(iv), and 14.4b(iv);

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f. the pressure drop across an oxidation catalyst unit is outside the acceptable range identified in the manufacturer's specifications, or outside the range determined by the most recent source tests under Conditions 14.2b(iv), 14.3b(iv), and 14.4b(iv); or

g. Conditions 14.1 through 14.6 are not met.

15. **Limited Use Diesel-Fired Engines BACT Emission Limits:** Limit the emissions from the limited use diesel-fired engines EUs 11 and 12 as specified in Table 5:

Table 5: Diesel-Fired Engines (EUs 11 and 12) – BACT Limits

Pollutant	EU	BACT Control	BACT Emission Limits		
NOx	11	Good Combustion Practices and Certified to Meet NSPS Subpart IIII	3.6 g/hp-hr		500 hours each in any 12 consecutive month period
	12		0.45 g/hp-hr		
CO	11	Oxidation Catalyst and Certified to Meet NSPS Subpart IIII	3.3 g/hp-hr		
	12	Good Combustion Practices and Certified to Meet NSPS Subpart IIII	3.3 g/hp-hr		
PM, PM-10, and PM-2.5	11	Good Combustion Practices and Certified to Meet NSPS Subpart IIII	0.19 g/hp-hr	10% opacity averaged over any six consecutive minutes	
	12		0.022 g/hp-hr		
SO_2	11 – 12	Good Combustion Practices & ULSD	Diesel sulfur content of ≤ 15 ppmw (ULSD)		
VOC	11	Oxidation Catalyst and Certified to Meet NSPS Subpart IIII	0.19 g/hp-hr		
	12	Good Combustion Practices and Certified to Meet NSPS Subpart IIII	0.22 g/hp-hr		
GHG	11 – 12	Good Combustion Practices	163.6 lb/MMBtu		

15.1 For EU 11 the Permittee shall:

a. Install, operate, and maintain an oxidation catalyst according to the manufacturer's specifications, at all times the unit is operating, except for short periods of startup, shutdown, and malfunction.

b. During periods of startup, shutdown, and malfunction operate the EU according to manufacturer's specifications and good combustion practices.

15.2 To show compliance with the emission limits for EUs 11 and 12 in Table 5, the Permittee shall:

a. At all times operate the EUs according to manufacturer's specifications and good combustion practices;

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b. Limit the operation of each of EUs 11 and 12 to no more than 500 hours in any 12 consecutive month period. Monitor, record, and report as follows:

(i) Install, operate, and maintain an hour meter on each EU;

(ii) Record the hour meter reading for each EU on the last day of each month;

(iii) By the 15th day of each month, calculate and record:

(A) the number of hours that each EU operated during the previous month, if the meter is not operational assume continuous operation for that period; and

(B) the total number of hours each EU operated during the previous 12 consecutive months;

(iv) Report in each operating report required by Condition 24 the following information for each month of the reporting period:

(A) the hour meter reading obtained under Condition 15.2b(ii) for each EU; and

(B) the values determined under Condition 15.2b(iii) for each EU; and

c. Verify initial compliance with the NOx + VOC, CO, PM, PM-10, and PM-2.5 emission limits for EUs 11 and 12, established in Table 5 by either:

(i) Obtaining a certified manufacturer's guarantee that each diesel engine will comply with the NOx + VOC, CO, PM, PM-10, and PM-2.5 emission limits established in Table 5. Submit the emissions data to the Department in the first operating report required by Condition 24 after each of EUs 11 and 12 become fully operational; or

(ii) Conducting an initial source test in accordance with Section 8, for NOx + VOC, CO, PM, PM-10, and PM-2.5 within 180 days of each of EUs 11 and 12 beginning operation.

d. Except as allowed by Condition 15.2d(ii), for EUs 11 and 12, conduct annual visible emission observations, the first to be completed within 180 days from the first of EUs 11 and 12 beginning operation to demonstrate compliance with the opacity limit in Table 5. The observations shall be conducted as specified by 40 C.F.R. 60, Appendix A-4, Method 9, adopted by reference in 18 AAC 50.040(a), for 18 minutes to obtain 72 consecutive 15-second opacity observations.

(i) Except as allowed by Condition 15.2d(ii), conduct subsequent visible emission observations within twelve months after the preceding observation.

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(ii) For an emission unit with intermittent operations, the required visual observations may be completed during the next scheduled operation immediately following the deadline stated in Condition 15.2d or 15.2d(i).

(iii) Record results using the Visible Emissions Observation Form found in Attachment 1 and report the results of all visible emissions observations in the operating report as required under Condition 24.

e. Verify compliance with the SO_2 emission limit listed in Table 5 by complying with Condition 11.1;

f. Perform regular maintenance following the manufacturer's or the operator's maintenance procedures;

g. Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format; and

h. Keep a copy of either the manufacturer's or the operator's maintenance procedures.

15.3 Report as described in Condition 23 if:

a. any of EUs 11 and 12 exceed 500 hours per 12 consecutive month period;

b. any of the emission rates determined by the source tests required by Conditions 15.2c(ii) exceed the limits in Table 5;

c. a six consecutive minute average opacity reading is above the limit in Table 5; or

d. any of Conditions 15.2a through 15.2g are not met.

16. **Vent Gas Disposal (Thermal Oxidizer) BACT Emission Limits:** Limit the emissions from thermal oxidizer EU 13 as specified in Table 6:

Table 6: EU 13 – BACT Limits

Pollutant	BACT Control	BACT Emission Limits
NOx	Low NOx Burners, Proper Equipment Design, & Good Combustion Practices	0.055 lb/MMBtu
CO	Proper Equipment Design Good Combustion Practices	0.082 lb/MMBtu
PM, PM-10, and PM-2.5	Proper Equipment Design Good Combustion Practices	0.0075 lb/MMBtu
SO_2	Proper Equipment Design Good Combustion Practices	Burn Gas with total Sulfur Content of ≤ 16 ppmv
VOC	Proper Equipment Design Good Combustion Practices	0.0054 lb/MMBtu
GHG	Proper Equipment Design Good Combustion Practices	117.1 lb/MMBtu

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16.1 To show compliance with the emission limits for EU 13 in Table 6, the Permittee shall:

a. Install, operate, and maintain low NOx burners according to the manufacturer's specifications, at all times the unit is operating;

b. During periods of startup, shutdown, and malfunction operate EU 13 according to manufacturer's specifications and good combustion practices;

c. Verify initial compliance with the NOx, CO, VOC, PM, PM-10, and PM-2.5 emission limits established in Table 6 as follows:

(i) Obtain a certified manufacturer's guarantee that the thermal oxidizer will comply with the emission limits established in Table 6. Submit the emissions data to the Department in the first operating report required by Condition 24 after EU 13 commences operation; or

(ii) Conduct a source test in accordance with Section 8 for NOx, CO, VOC, PM, PM-10, and PM-2.5 within 180 days of startup of EU 13.

d. To show compliance with the SO_2 emission limit set out in Table 6, the Permittee shall comply with Condition 11.2. Report as described in Condition 23 whenever the sulfur content of the fuel gas fired in EU 13 exceeds 16 ppmv;

e. Perform regular maintenance according to the manufacturer's or the operator's maintenance procedures;

f. Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format; and

g. Keep a copy of either the manufacturer's or the operator's maintenance procedures.

17. **Vent Gas Disposal (Flares) BACT Emission Limits:** Limit the emissions from flaring EUs 14, 16, and 18 as specified in Table 7, EUs 15, 17, and 19 as specified in Table 8, and EU 20 as specified in Table 9.

Table 7: EUs 14, 16, and 18 – BACT Limits

Pollutant	EUs	BACT Control	BACT Emission Limits	
NOx	14, 16, & 18	Proper flare work practice requirements and following the flaring minimization plan	0.068 lb/MMBtu	1,000 hours combined per 12-month rolling period during startup, shutdown, and maintenance events[9]
CO			0.31 lb/MMBtu	
PM, PM-10, and PM-2.5			40 µg/L (0.028 lb/MMBtu)	
SO_2			Burn Gas with total Sulfur Content of ≤ 16 ppmv	
VOC			0.66 lb/MMBtu	

[9] The 1,000-hour combined flaring limits do not include pilot and purge, emergency, or process upset flaring.

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GHG			117.1 lb/MMBtu	

Table 8: : EUs 15, 17, and 19 – BACT Limits

Pollutant	EUs	BACT Control	BACT Emission Limits	
NOx	15, 17, & 19	Proper flare work practice requirements and following the flaring minimization plan	0.068 lb/MMBtu	1,000 hours combined per 12-month rolling period during startup, shutdown, and maintenance events[9]
CO			0.31 lb/MMBtu	
PM, PM-10, and PM-2.5			40 µg/L (0.028 lb/MMBtu)	
SO_2			Burn Gas with total Sulfur Content of ≤ 16 ppmv	
VOC			0.66 lb/MMBtu	
GHG			117.1 lb/MMBtu	

Table 9: EU 20 – BACT Limits

Pollutant	EU	BACT Control	BACT Emission Limits	
NOx	20	Proper flare work practice requirements and following the flaring minimization plan	0.068 lb/MMBtu	144 hours per 12-month rolling period during startup, shutdown, and maintenance events[10]
CO			0.31 lb/MMBtu	
PM, PM-10, and PM-2.5			40 µg/L (0.028 lb/MMBtu)	
SO_2			Burn Gas with total Sulfur Content of ≤ 16 ppmv	
VOC			0.66 lb/MMBtu	
GHG			117.1 lb/MMBtu	

17.1 To show compliance with the work practice and flaring minimization BACT limits for EUs 14, 16, and 18 indicated in Table 7, EUs 15, 17, and 19 as indicated in Table 8, and EU 20 as indicated in Table 9, the Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and maintenance events:

a. Flare Minimization Plan: The Permittee shall implement the procedures outlined in the flare minimization plan contained in Section 11 and keep a copy of the plan on-site;

b. The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices contained in Section 11 and the specific procedures to follow during process startup, shutdown, and other flaring events; and

[10] The 144-hour flaring limit does not include pilot and purge, emergency, or process upset flaring.

c. Flares shall be designed and operated during startups, shutdowns, and other maintenance events, in accordance with the general control device and work practice requirements specified in 40 C.F.R. 60.18(c) through (f) and the flare minimization plan contained in Section 11.

17.2 During startup, shutdown, and maintenance events, limit the number of hours flared in any 12 consecutive months to no more than: 1,000 hours combined for EUs 14, 16, and 18, 1,000 hours combined for EUs 15, 17, and 19, and 144 hours for EU 20.[9,10]

Monitor, record, and report as follows:

a. Calculate and record monthly, the number of hours EUs 14 through 20 flared during startups, shutdowns, and other maintenance events for the previous month;

b. Calculate and record monthly, the number of hours EUs 14 through 20 flared during startups, shutdowns, and other maintenance events for the previous 12 consecutive months;

c. Report in the operating report required in Condition 24, for each month covered in the report, the total hours that each of EUs 14 through 20 flared for the previous 12 consecutive months; and

d. Report as described in Condition 23 whenever the flaring hours calculated under Condition 17.2b exceed the limits in Condition 17.2.

17.3 To show compliance with the SO_2 emission limit set out in Table 7, Table 8, and Table 9, the Permittee shall comply with Condition 11.2. Report as described in Condition 23 whenever the sulfur content of the fuel gas fired in EUs 14 through 20 exceeds 16 ppmv.

18. **Fuel Tanks BACT Emission Limits:** Limit the emissions from fuel tanks EUs 21 through 26 as specified in Table 10:

Table 10: EUs 21 through 61 – BACT Limits

Pollutant	EU	BACT Control	BACT Emission Limit
VOC	21 – 23	Capture and Recovery through Vapor Balance System and Route to Thermal Oxidizer	N/A
	24 – 26	Submerged Fill	0.01 tpy

18.1 To show compliance with the VOC emission limit for gas condensate storage tanks EUs 21 and 22 and gas condensate loading system EU 23 set out in Table 10, the Permittee shall install, operate, and maintain capture and recovery through a vapor balance system and combustion of vapors in a thermal oxidizer (EU 13), at all times the units are operating.

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18.2 To show compliance with the VOC emission limit for diesel fuel tanks EUs 24 through 26 set out in Table 10, the Permittee shall install, operate, and maintain tanks with submerged fill design.

18.3 Compliance with the VOC limit in Table 10 shall be demonstrated by supplying the Department with as built schematics and photographs of the capture and recovery vapor balance system, demonstrating compliance with Condition 18.1 in the first operating report required under Condition 24 after installation of the tanks and control system.

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Section 6 *Recordkeeping, Reporting, and Certification Requirements*

19. **Certification.** The Permittee shall certify any permit application, report, affirmation, or compliance certification submitted to the Department and required under the permit by including the signature of a responsible official for the permitted stationary source following the statement: "*Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.*" Excess emissions reports must be certified either upon submittal or with an operating report required for the same reporting period. All other reports and other documents must be certified upon submittal.

    19.1 The Department may accept an electronic signature on an electronic application or other electronic record required by the Department if

        a. A certifying authority registered under AS 09.25.510 verifies that the electronic signature is authentic; and

        b. The person providing the electronic signature has made an agreement with the certifying authority described in Condition 19.1a that the person accepts or agrees to be bound by an electronic record executed or adopted with that signature.

20. **Submittals.** The Permittee shall submit reports, compliance certifications, and/or other submittals required by this permit, via the Department's website (AOS System at http://dec.alaska.gov/applications/air/airtoolsweb using the Permittee Portal option).

    20.1 Upon approval by the Department, the Permittee can submit reports by alternative methods, certified in accordance with Condition 19, and submitted by email under a cover letter using dec.aq.airreports@alaska.gov; or by letter, or form if the Permittee does not have the technical ability to submit the records using the Department's website.

21. **Information Requests.** The Permittee shall furnish to the Department, within a reasonable time, any information the Department requests in writing to determine whether cause exists to modify, revoke, reissue, or terminate the permit or to determine compliance with the permit. Upon request, the Permittee shall furnish to the Department copies of records required to be kept by the permit. The Department may require the Permittee to furnish copies of those records directly to the federal administrator.

22. **Recordkeeping Requirements.** The Permittee shall keep all records required by this permit for at least five-years after the date of collection, including:

    22.1 copies of all reports and certifications submitted pursuant to this section of the permit; and

    22.2 records of all monitoring required by this permit, and information about the monitoring including (if applicable):

        a. calibration and maintenance records, original strip chart or computer-based recordings for continuous monitoring instrumentation;

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b. sampling dates and times of sampling or measurements;

c. the operating conditions that existed at the time of sampling or measurement;

d. the date analyses were performed;

e. the location where samples were taken;

f. the company or entity that performed the sampling and analyses;

g. the analytical techniques or methods used in the analyses; and

h. the results of the analyses.

23. **Excess Emissions and Permit Deviation Reports.**

23.1 Except as provided in Condition 25 the Permittee shall report all emissions or operations that exceed or deviate from the requirements of this permit as follows:

a. In accordance with 18 AAC 50.240(c), as soon as possible after the event commenced or is discovered, report

(i) emissions that present a potential threat to human health or safety; and

(ii) excess emissions that the Permittee believes to be unavoidable;

b. in accordance with 18 AAC 50.235(a), within two working days after the event commenced or was discovered, report an unavoidable emergency, malfunction, or nonroutine repair that caused emissions in excess of a technology based emissions standard;

c. report all other excess emissions and permit deviations

(i) within 30 days after the end of the month during which the emissions or deviation occurred, except as provided in Condition 23.1c(iii); or

(ii) if a continuous or recurring excess emissions is not corrected within 48 hours of discovery, within 72 hours of discovery unless the Department provides written permission to report under Condition 23.1c(i); and

(iii) for failure to monitor, as required in other applicable conditions of this permit.

23.2 When reporting either excess emissions or permit deviations, the Permittee shall report using either the Department's on-line form, which can be found at http://dec.alaska.gov/applications/air/airtoolsweb, or if the Permittee prefers, the form contained in Attachment 2 of this permit. The Permittee must provide all information called for by the form that is used.

23.3 If requested by the Department, the Permittee shall provide a more detailed written report as requested to follow up an excess emissions report.

24. **Operating Reports.** Submit to the Department an operating report by August 1 for the period January 1 through June 30 of the current year and by February 1 for the period July

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1 through December 31 of the previous year. The report shall be submitted under a cover letter certified in accordance with Condition 19.

24.1 The operating report must include all information required to be in operating reports by other conditions of this permit, for the period covered by the report.

24.2 When excess emissions or permit deviations that occurred during the reporting period are not reported under Condition 24.1, the Permittee shall identify

a. the date of the deviation;

b. the equipment involved;

c. the permit condition affected;

d. a description of the excess emissions or permit deviation; and

e. any corrective action or preventative measures taken and the date of such actions; or

24.3 When excess emissions or permit deviations have already been reported under Condition 23 the Permittee shall cite the date or dates of those reports.

25. **Air Pollution Prohibited.** No person may permit 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.

25.1 If emissions present a potential threat to health or safety, the Permittee shall report any such emissions according to Condition 23.

25.2 As soon as practicable after becoming aware of a complaint that is attributable to emissions from the stationary source, the Permittee shall investigate the complaint to identify emissions that the Permittee believes have caused or are causing a violation of Condition 25.

25.3 The Permittee shall initiate and complete corrective action necessary to eliminate any violation identified by a complaint or investigation as soon as practicable if

a. after investigation because of complaint or other reason, the Permittee believes that emissions from the stationary source have caused or are causing a violation of Condition 25; or

b. the Department notifies the Permittee that it has found a violation of Condition 25.

25.4 The Permittee shall keep records of

a. the date and time, and nature of all emissions complaints received;

b. the name of the person or persons that complained, if known;

c. a summary of any investigation, including reasons the Permittee does or does not believe the emissions have caused a violation of Condition 25; and

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d. any corrective actions taken or planned for complaints attributable to emissions from the stationary source.

25.5 Report in each operating report required by Condition 24 a brief summary report for complaints which must include:

a. the number of complaints received;

b. the number of times the Permittee or the Department found corrective action necessary;

c. the number of times action was taken on a complaint within 24 hours; and

d. the status of corrective actions the Permittee or Department found necessary that were not taken within 24 hours.

25.6 The Permittee shall notify the Department of a complaint that is attributable to emissions from the stationary source within 24 hours after receiving the complaint, unless the Permittee has initiated corrective action within 24 hours of receiving the complaint.

26. **Emission Inventory Reporting.** The Permittee shall submit to the Department reports of actual emissions,[11] by emissions unit, of CO, NH_3, NOx, PM_{10}, $PM_{2.5}$, SO_2, VOCs and Lead (Pb) (and lead compounds) using the form in Attachment 3 of this permit, as follows:

26.1 Each year by April 30, if the stationary source's potential to emit for the previous calendar year equals or exceeds:

a. 250 TPY of NH_3, PM_{10}, $PM_{2.5}$, or VOCs; or

b. 2,500 TPY of CO, NOx, or SO_2.

26.2 Every third year by April 30, if the stationary source's potential to emit for the previous calendar year (except actual emissions for Pb) equals or exceeds:

a. 0.5 TPY of actual Pb, or

b. 1,000 TPY of CO; or

c. 100 TPY of SO_2, NH_3, PM_{10}, $PM_{2.5}$, NOx, or VOCs.

26.3 For reporting under Condition 26.2, the Permittee shall report in 2021 for calendar year 2020, 2024 for calendar year 2023, etc., in accordance with the Environmental Protection Agency schedule.

26.4 Include in the report required by this condition, the required data elements contained within the form in Attachment 3 or those contained in Tables 2a and 2b of Appendix

[11] If the stationary source has not commenced construction or operation by the end of the calendar year, submit a transmittal letter to the Department's Anchorage office certified in accordance with Condition 20, which identifies the source's emissions inventory for the previous fiscal year to be zero tons per year and provide estimates for when construction and operation will commence.

A to Subpart A of 40 C.F.R. 51 and Emission Inventory Instructions available in Air Online Services (AOS) system for each emissions unit.

a. Submit the report through electronic online submission via the Department's AOS system at http://dec.alaska.gov/applications/air/airtoolsweb using the Permittee Portal option.

b. If the AOS system is not available, the report may be submitted by

   (i) email using dec.aq.airreports@alaska.gov; or

   (ii) hard copy to the following address: ADEC Air Permits Program, ATTN: Emissions Inventory, 555 Cordova Street, Anchorage, Alaska 99501.

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Section 7 *Standard Permit Conditions*

27. The Permittee must comply with each permit term and condition. Noncompliance with a permit term or condition constitutes a violation of AS 46.14, 18 AAC 50, and, except for those terms or conditions designated in the permit as not federally enforceable, the Clean Air Act, and is grounds for

    27.1 an enforcement action; or

    27.2 permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280.

28. It is not a defense in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with a permit term or condition.

29. Each permit term and condition is independent of the permit as a whole and remains valid regardless of a challenge to any other part of the permit.

30. The permit may be modified, reopened, revoked and reissued, or terminated for cause. A request by the Permittee for modification, revocation and reissuance, or termination or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

31. The permit does not convey any property rights of any sort, nor any exclusive privilege.

32. The Permittee shall allow the Department or an inspector authorized by the Department, upon presentation of credentials and at reasonable times with the consent of the owner or operator to

    32.1 enter upon the premises where an emissions unit subject to this permit is located or where records required by the permit are kept;

    32.2 have access to and copy any records required by this permit;

    32.3 inspect any stationary source, equipment, practices, or operations regulated by or referenced in the permit; and

    32.4 sample or monitor substances or parameters to assure compliance with the permit or other applicable requirements.

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Section 8 *General Source Test Requirements*

33. **Requested Source Tests.** In addition to any source testing explicitly required by this permit, the Permittee shall conduct source testing as requested by the Department to determine compliance with applicable permit requirements.

34. **Operating Conditions.** Unless otherwise specified by an applicable requirement or test method, the Permittee shall conduct source testing

    34.1 at a point or points that characterize the actual discharge into the ambient air; and

    34.2 at the maximum rated burning or operating capacity of the emissions unit or another rate determined by the Department to characterize the actual discharge into the ambient air.

35. **Reference Test Methods.** The Permittee shall use the following references for test methods when conducting source testing for compliance with this permit:

    35.1 Conduct source testing for compliance with requirements adopted by reference in 18 AAC 50.040(a) in accordance with the methods and procedures specified in 40 CFR 60.

    35.2 Conduct source testing for compliance with requirements adopted by reference in 18 AAC 50.040(b) in accordance with the methods and procedures specified in 40 CFR 61.

    35.3 Conduct source testing for compliance with requirements adopted by reference in 18 AAC 50.040(c) in accordance with the methods and procedures specified in 40 CFR 63.

    35.4 Source testing for the reduction in visibility through the exhaust effluent must be conducted in accordance with the procedures set out in 40 C.F.R. 60, Appendix A, Reference Method 9. The Permittee may use the form in Attachment 1 of this permit to record data.

    35.5 Source testing for emissions of total particulate matter, sulfur compounds, nitrogen compounds, carbon monoxide, lead, volatile organic compounds, fluorides, sulfuric acid mist, municipal waste combustor organics, metals and acid gases must be conducted in accordance with the methods and procedures specified in 40 C.F.R. 60, Appendix A.

    35.6 Source testing for emissions of PM-10 and PM-2.5 must be conducted in accordance with the procedures specified in 40 C.F.R. 51, Appendix M, Methods 201 or 201A and 202.

    35.7 Source testing for emissions of any contaminant may be determined using an alternative method approved by the Department in accordance with 40 C.F.R. 63 Appendix A, Method 301.

36. **Test Deadline Extension.** The Permittee may request an extension to a source test deadline established by the Department. The Permittee may delay a source test beyond the

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original deadline only if the extension is approved in writing by the Department's appropriate division director or designee.

37. **Test Plans.** Before conducting any source tests, the Permittee shall submit a plan to the Department. The plan must include the methods and procedures to be used for sampling, testing, and quality assurance and must specify how the emissions unit will operate during the test and how the Permittee will document that operation. The Permittee shall submit a complete plan within 60 days after receiving a request under Condition 33 and at least 30 days before the scheduled date of any test unless the Department agrees in writing to some other time period. Retesting may be done without resubmitting the plan.

38. **Test Notification.** At least 10 days before conducting a source test, the Permittee shall give the Department written notice of the date and time the source test will begin.

39. **Test Reports.** Within 60 days after completing a source test, the Permittee shall submit one certified copy of the results in the format set out in the *Source Test Report Outline*, adopted by reference in 18 AAC 50.030. The Permittee shall certify the results in the manner set out in Condition 19. If requested in writing by the Department, the Permittee must provide preliminary results in a shorter period of time specified by the Department.

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Section 9 *Permit Documentation*

Date	Document Details
May 1, 2018	Construction Permit application received.
June 29, 2018	Department sends incompleteness letter to Permittee
September 24, 2018	Department receives additional application information
October 17, 2019	Department receives ambient monitoring data
January 14, 2020	Department receives additional application information
April 28, 2020	Deparment sends information request to Permittee
May 5, 2020	Department receives information request response from Permittee
June 18, 2020	Deparment sends information request to Permittee
July 1, 2020	Department receives information request response from Permittee
September 9, 2020	Department public notices preliminary permit
September 29, 2020	Department extends public notice period 30 days
September 29, 2020	Department receives clarification on CBI of BACT material from Permittee
November 2 & 4, 2020	Department receives response from Permittee releasing all application material from CBI
November 6, 2020	Department extends public notice period 30 days
November 9, 2020	Department receives information request response from Permittee
November 11, 2020	Department receives modeling files from Permittee for public notice
February 1, 2021	Department receives material from Permittee regarding nitrogen deposition in Denali National Park
March 10, 2021	Department sends email to Permittee regarding SCR on turbines
March 25, 2021	Department receives request from Permittee to pause work on issuing the final permit
April 13, 2022	Department receives updated BACT analysis from Permittee
May 3, 2022	Department resumes work on issuing final permit
May 12, 2022	Department sends information request to Permittee
May 27, 2022	Depatment receives information request response from Permittee
May 27, 2022	Department sends information request to Permittee
June 3, 6, & 7, 2022	Department receives information request responses from Permittee
June 13, 2022	Department sends information request to Permittee
Juneu 14, 2022	Department receives information request response from Permittee
See also:	https://dec.alaska.gov/air/air-permit/liquefaction-plant-application/

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Section 10 Complaint Form

COMPLAINT FORM

Date Time:

Activities Involved:

Provide a description of reported complaint. Attach sheets as necessary.

If applicable, operational conditions which contributed to the complaint:

If applicable, ambient conditions which contributed to the complaint:

If applicable, describe measures taken to immediately address the complaint.

If applicable, describe measures taken to address preventing the condition which generated the complaint.

If applicable, describe any reason that you feel the complaint may not be a violation:

Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate and complete.

Printed Name	Signature	Date

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Section 11 Flare Minimization Plan

ALASKA LNG

Flare Minimization Plan

May 26, 2022

3043-AIR-PLN 00002

Alaska Gasline Development Corporation
3201 C Street, Suite 201
Anchorage, Alaska 99503
T: 907-330-6300
www.alaska-lng.com

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1. INTRODUCTION

The Alaska LNG Liquefaction Plant will utilize three flare gas systems (i.e., wet, dry, and low-pressure, EUs 14 - 20) to route relief vapors from separate sections of the plant into their respective flare collection headers. The wet flare gas system (EUs 15, 17, and 19) will control waste gas streams containing a significant concentration of water and heavier compounds. The dry flare gas system (EUs 14, 16, and 18) will be used for safe disposal of dry hydrocarbons streams discharged downstream of the dehydration unit. The low-pressure BOG flare gas system (EU 20) will be used for safe disposal of intermittent, low-pressure operational release from the LNG storage and loading system and intermittent maintenance purging of inert gas from LNG carriers. These flare systems prevent the direct relief to the atmosphere of vent gases that contain VOC and GHG (in the form of CH4). The flares will emit CO, NOx, SO2, particulates, VOC, and GHG

Applicability

In accordance with Alaska Department of Environmental Conservation (ADEC) Air Quality Construction Permit No. AQ1539CPT01 Best Available Control Technology (BACT) determination, implementation of Flare Minimization Plan is required for controlling CO, NOx, SO2, particulates, VOC, and GHG emissions. The plan will apply to the following emissions units:

EU No.	Description	Fuel	Rating/Max Capacity
14	Dry Ground Flare #1	Fuel Gas/Process Gas	55,000 Mscf/hr
15	Wet Ground Flare #1	Fuel Gas/Process Gas	13,000 Mscf/hr
16	Dry Ground Flare #2	Fuel Gas/Process Gas	55,000 Mscf/hr
17	Wet Ground Flare #2	Fuel Gas/Process Gas	13,000 Mscf/hr
18	Dry Ground Flare #3	Fuel Gas/Process Gas	55,000 Mscf/hr
19	Wet Ground Flare #3	Fuel Gas/Process Gas	13,000 Mscf/hr
20	Elevated Low Pressure Flare	Fuel Gas/Process Gas	990 Mscf/hr

Purpose

Flare gas minimization techniques are commonly employed at oil and gas, refining, and petrochemical facilities. New Source Performance Standard (NSPS) Subpart Ja regulates flaring at petroleum refineries. This NSPS requires refineries to prepare and submit for review by the Administrator a Flare Gas Management Plan detailing the procedures a facility will implement to minimize flare emissions to the atmosphere.[1] Additionally, state and local air pollution control rules require preparation and implementation of Flare Gas Minimization Plans.[2] AGDC proposes to implement the following plan to minimize flaring, similar the measures employed by these federal, state, and local air pollution control standards.

[1] See 40 CFR 60.103a(a)

[2] For example, see SCAQMD Rule 1118, BAAQMD Regulation 12, Rule 11, and SJVAPCD Rule 4311.

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Current Design Basis

The current flaring design basis is outlined as follows and is subject to updates during the final design process prior to construction and operations.

The flare system will be installed to protect personnel and equipment from the potential hazards created by unexpected operating excursions as well as controlled reliefs during various operations (e.g., start-up, off-spec flaring etc.) from the LNG liquefaction trains and the supporting facilities. The design and operating basis do not include routine or continuous venting of gas to flare for general service disposal purposes.

The major flaring contingencies included in the current design considered multiple scenarios/cases for the dry and wet ground flares and LP flare. The maximum flaring load cases in terms of volumetric and vapor flow rates (lbs/hour) occur with the dry flares. Those cases include the following operating events:

1. Mixed Refrigerant (MR) Compressor Blocked Outlet - blocked outlet on the MR Compressor in Train 1 + Train 2 start-up
2. Propane Compressor Blocked Outlet - blocked outlet on the Propane Compressor in Train 1 + Train 2 start-up
3. Start-up Flaring (@ 35% of Normal Flow) - assumed that during start-up, 35% of the normal flow to 1 LNG train will be routed to the Dry Flare from downstream of the Dehydration Unit
4. Governing Case for Dry Liquids - For the purpose of sizing Dry Flare KO Drum, it is assumed that it may be required to route 35% of LNG from one train to the Dry Liquid Disposal for short term.

The design basis for maximum governing case for the dry flares is for the vapor flow rate associated with a blocked outlet on the Propane Compressor in Train 1 + Train 2 start-up at 35% of normal flow.

Wet Flare governing cases are as follows:

5. Vapor Flow Rate (from both volumetric flow and radiation point of view): Control Valve Failure in HP Fuel Gas System.
6. Liquid Flow Rate: 30 minutes of liquid accumulation in the Wet Flare KO Drum at peak condensate production rate.

LP flare governing cases as follows:

7. Vapor flow rate (from both volumetric flow and radiation point of view): BOG Compressor Failure during Loading Mode.
8. Liquid flow rate: 30 minutes accumulation of condensed liquids in the LP Flare KO Drum when C5+ vents from Condensate Storage and Loading are co-incident with another cryogenic load.

Operability and Maintainability Requirements

Planned maintenance shutdowns (turnarounds) will be scheduled and coordinated across Project facilities (e.g., GTP, Mainline, LNG Plant) to maximize overall Project availability.

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Piping, valving, and equipment will be designed to allow safe and effective isolations when making the necessary preparations for maintenance work. Vents and drains will be provided that allow for safe and effective depressurizing, draining, and purging of equipment.

Facilities will be designed to minimize the risk of upset conditions, and will also include the means of safe, easy, and quick mitigation or recovery should an upset condition occur (e.g., the ability to recover quickly from unplanned compressor trip).

Operating procedures will be developed during the construction phase of the project.

Flare Minimization Procedures

A. Pilot and Purge Gas Optimization

The only continuous combustion at the flares is from pilot and purge gases. Pilot and purge gas emissions can be substantial if the flows are not optimized. AGDC proposes to work with the flare manufacturers to optimize these continuous flows. Purge gas flows shall be minimized to the extent feasible to prevent oxygen intrusion into the flare gas system. AGDC will confirm the settings for pilot and purge gases upon start-up, and as needed to prevent oxygen intrusion in the flare gas system.

B. Start-up and Shutdown Flaring

The process of starting up and shutting down equipment for turnaround and other maintenance activities will require the facility to de-pressure equipment to the flare. The volume of gases flared can be reduced through proper planning and consolidation of activities requiring start-ups and shutdowns. To the extent feasible, AGDC will consolidate maintenance events to reduce the volume and duration of flaring activities. Flaring during major facility maintenance activities or turnarounds will be planned so that flaring durations and volumes are minimized.

C. Intermittent Flaring from Maintenance and Other Operations

During operations, it will be necessary to flare process gas to reduce the operating pressure on equipment. To the extent feasible, AGDC will minimize gas volumes by isolating and depressurizing process areas subject to maintenance operation, and redirect/recover gases to the operating process prior to blowing down the equipment to the flare.

D. Plant Imbalances

Occasionally, the facility will be subject to fuel gas and other production imbalances. These conditions will require the temporary flaring of fuel, natural gas, and/or LNG. AGDC proposes to minimize these imbalances by slowing production rates and making other adjustments necessary to reduce the duration of these transient conditions.

E. Unplanned Flaring

Unplanned flaring can occur from process upsets and emergency conditions. AGDC will prepare and follow operating procedures for specific unplanned events, including possible equipment malfunctions. These procedures will incorporate flare minimization techniques to address duration and volume of gases flared. To further reduce flaring from unplanned events, AGDC proposes to implement the following procedure

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for all unplanned events resulting in the combustion of 500,000 scfd or more of gas in any 24-hour period. The threshold for implementing this procedure is based on NSPS Subpart Ja requirements.

1. AGDC will conduct a Root Cause Analysis (RCA) and Corrective Action Analysis (CAA) for the event. The RCA and CAA will be conducted no later than 45-days after the discharge to the flare occurs. The RCA will evaluate the circumstances and causes for the flaring and the CAA will identify the procedural and equipment changes that will be made to minimize and/or avoid the event in the future.
2. Appropriate corrective actions identified in the CAA shall be implemented within the 45-days of the event. If certain corrective actions cannot be completed within the 45-day period, AGDC shall develop and implement a schedule to complete the corrective action(s) as soon as possible. If AGDC concludes that specific corrective actions should not be implemented, AGDC shall record as part of the CAA the reasons why such action(s) do not need to be taken.
3. AGDC shall document all RCAs and CAAs and retain them for a period of five-years. Records of RCAs and CAAs shall be made available to ADEC upon request.

An RCA and/or CAA will not be prepared for flaring caused by fuel gas/process gas imbalances, planned start-ups, shutdowns, or due to planned de-pressuring of equipment for maintenance or other process conditions. During planned events, including start-up and shutdown, AGDC is required to minimize flaring emissions to the extent feasible as described above in this plan.

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Attachment 1 – Visible Emissions Form

VISIBLE EMISSION OBSERVATION FORM

This form is designed to be used in conjunction with EPA Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources." Temporal changes in emission color, plume water droplet content, background color, sky conditions, observer position, etc. should be noted in the comments section adjacent to each minute of readings. Any information not dealt with elsewhere on the form should be noted under additional information. Following are brief descriptions of the type of information that needs to be entered on the form: for a more detailed discussion of each part of the form, refer to "Instructions for Use of Visible Emission Observation Form."

- Source Name: full company name, parent company or division or subsidiary information, if necessary.
- Address: street (not mailing or home office) address of facility where VE observation is being made.
- Phone (Key Contact): number for appropriate contact.
- Source ID Number: number from NEDS, agency file, etc.
- Process Equipment, Operating Mode: brief description of process equipment (include type of facility) and operating rate, % capacity, and/or mode (e.g. charging, tapping, shutdown).
- Control Equipment, Operating Mode: specify type of control device(s) and % utilization, control efficiency.
- Describe Emission Point: for identification purposes, stack or emission point appearance, location, and geometry; and whether emissions are confined (have a specifically designed outlet) or unconfined (fugitive).
- Height Above Ground Level: stack or emission point height relative to ground level; can use engineering drawings, Abney level, or clineometer.
- Height Relative to Observer: indicate height of emission point relative to the observation point.
- Distance from Observer: distance to emission point; can use rangefinder or map.
- Direction from Observer: direction plume is traveling from observer.
- Describe Emissions and Color: include physical characteristics, plume behavior (e.g., looping, lacy, condensing, fumigating, secondary particle formation, distance plume visible, etc.), and color of emissions (gray, brown, white, red, black, etc.). Note color changes in comments section.
- Visible Water Vapor Present?: check "yes" if visible water vapor is present.
- If Present, is Plume…: check "attached" if water droplet plume forms prior to exiting stack, and "detached" if water droplet plume forms after exiting stack.
- Point in Plume at Which Opacity was Determined: describe physical location in plume where readings were made (e.g., 1 ft above stack exit or 10 ft. after dissipation of water plume).
- Describe Plume Background: object plume is read against, include texture and atmospheric conditions (e.g., hazy).
- Background Color: sky blue, gray-white, new leaf green, etc.
- Sky Conditions: indicate cloud cover by percentage or by description (clear, scattered, broken, overcast).
- Wind Speed: record wind speed; can use Beaufort wind scale or hand-held anemometer to estimate.
- Wind Direction From: direction from which wind is blowing; can use compass to estimate to eight points.
- Ambient Temperature: in degrees Fahrenheit or Celsius.
- Wet Bulb Temperature: can be measured using a sling psychrometer
- RH Percent: relative humidity measured using a sling psychrometer; use local US Weather Bureau measurements only if nearby.
- Source Layout Sketch: include wind direction, sun position, associated stacks, roads, and other landmarks to fully identify location of emission point and observer position.
- Draw North Arrow: to determine, point line of sight in direction of emission point, place compass beside circle, and draw in arrow parallel to compass needle.
- Sun's Location: point line of sight in direction of emission point, move pen upright along sun location line, mark location of sun when pen's shadow crosses the observer's position.
- Observation Date: date observations conducted.
- Start Time, End Time: beginning and end times of observation period (e.g., 1635 or 4:35 p.m.).
- Data Set: percent opacity to nearest 5%; enter from left to right starting in left column. Use a second (third, etc.) form, if readings continue beyond 30 minutes. Use dash (-) for readings not made; explain in adjacent comments section.
- Comments: note changing observation conditions, plume characteristics, and/or reasons for missed readings.

  Range of Opacity: note highest and lowest opacity number.
- Observer's Name: print in full.
- Observer's Signature, Date: sign and date after performing VE observation.
- Organization: observer's employer.
- Certified By, Date: name of "smoke school" certifying observer and date of most recent certification.

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ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY DIVISION - VISIBLE EMISSIONS OBSERVATION FORM

Page No._____

Source Name	Type of Source	Observation Date	Start Time / End Time
Address			
City / State / Zip			
Phone # (Key Contact)	Source ID Number		
Process Equipment	Operating Mode		
Control Equipment	Operating Mode		
Describe Emission Point			
Height above ground level	Height relative to observer	Inclinometer Reading	
Distance From Observer	Direction From Observer: Start / End		
Describe Emissions & Color: Start	End		
Visible Water Vapor Present? No / Yes	If yes, determine approximate distance from the stack exit to where the plume was read		
Point in Plume at Which Opacity Was Determined			
Describe Plume Background: Start / End	Background Color: Start / End		
Sky Conditions: Start			
Wind Speed	Wind Direction From: Start / End		
Ambient Temperature	Wet Bulb Temp	RH percent	

NOTES: 1 Stack or Point Being Read 2 Wind Direction From
3 Observer Location 4 Sun Location 5 North Arrow 6 Other Stacks

Min \ Sec	0	15	30	45	Comments
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					

Range of Opacity
Minimum Maximum

I have received a copy of these opacity observations
Print Name:
Signature:
Title Date

Print Observer's Name
Observer's Signature Date
Organization
Certified By: Date

Attachment 2 - ADEC Notification Form

Excess Emissions and Permit Deviation Reporting
State of Alaska Department of Environmental Conservation
Division of Air Quality

Liquefaction Plant — AQ1539CPT01
Stationary Source Name — **Air Quality Permit**

Alaska Gasline Development Corporation
Company Name — **Date**

When did you discover the Excess Emissions/Permit Deviation?

Date: _____ / _____ / _____ Time: _____ :/ _____

When did the event/deviation?

Begin Date: _____ / _____ / _____ Time: _____ : _____ (Use 24-hr clock.)

End Date _____ / _____ / _____ Time: _____ : _____ (Use 24-hr clock.)

What was the duration of the event/deviation? ____ : ____ (hrs:min) or _____ days

(total # of hrs, min, or days, if intermittent then include only the duration of the actual emissions/deviation)

Reason for notification: (please check only 1 box and go to the corresponding section)

☐Excess Emissions Complete Section 1 and Certify

☐Deviation from permit conditions complete Section 2 and certify

☐Deviation from COBC, CO, or Settlement Agreement Complete Section 2 and certify

Section 1. Excess Emissions

(a) **Was the exceedance** ☐Intermittent or ☐Continuous

(b) **Cause of Event (Check one that applies):**

☐Start Up/Shut Down ☐Natural Cause (weather/earthquake/flood)

☐Control Equipment Failure ☐Scheduled Maintenance/Equipment Adjustments

☐Bad fuel/coal/gas ☐Upset Condition ☐Other

(c) **Description**

Describe briefly, what happened and the cause. Include the parameters/operating conditions exceeded, limits, monitoring data and exceedance.

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(d) **Emission unit(s) Involved:**

Identify the emission units involved in the event, using the same identification number and name as in the permit. Identify each emission standard potentially exceeded during the event and the exceedance.

EU ID	EU Name	Permit Condition Exceeded/Limit/Potential Exceedance

(e) **Type of Incident** (please check only one):

☐Opacity % ☐Venting (gas/scf) ☐Control Equipment Down
☐Fugitive Emissions ☐Emission Limit Exceeded ☐Record Keeping Failure
☐Marine Vessel Opacity ☐Failure to monitor/report ☐Flaring
☐Other:

(f) **Unavoidable Emissions:**

Do you intend to assert that these excess emissions were unavoidable? ☐YES ☐NO
Do you intend to assert the affirmative defense of 18 AAC 50.235? ☐YES ☐NO

Certify Report (go to end of form)

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Section 2. Permit Deviations

(a) **Permit Deviation Type** (check only one box corresponding with the section in the permit)

☐ Emission Unit Specific
☐ General Source Test/Monitoring Requirements
☐ Recordkeeping/Reporting/Compliance Certification
☐ Standard Conditions Not Included in Permit
☐ Generally Applicable Requirements
☐ Reporting/Monitoring for Diesel Engines
☐ Insignificant Emission Unit
☐ Stationary Source-Wide
☐ Other Section: (title of section and section # of your permit)

(b) **Emission unit(s) Involved:**

Identify the emission unit involved in the event, using the same identification number and name as in the permit. List the corresponding Permit condition and the deviation.

EU ID	Emission Unit Name	Permit Condition /Potential Deviation

(c) **Description of Potential Deviation:**

Describe briefly, what happened and the cause. Include the parameters/operating conditions and the potential deviation.

(d) **Corrective Actions:**

Describe actions taken to correct the deviation or potential deviation and to prevent future recurrence.

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Certification:

Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.

Printed Name: _____ Title: _____ Date: _____

Signature: _____ Phone Number: _____

NOTE: *This document must be certified in accordance with 18 AAC 50.345(j)*

To submit this report:

1. Department's Air Online Services using the Permittee Portal option:
   http://dec.alaska.gov/applications/air/airtoolsweb
   If submitted online, report must be submitted by an authorized E-Signer for the stationary source.

Or

2. Fax to: 907-451-2187

Or

3. Email to: DEC.AQ.Airreports@alaska.gov

Or

4. Mail to:ADEC
   Air Permits Program
   610 University Avenue
   Fairbanks, AK 99709-3643

Or

5. Phone Notifications: 907-451-5173
   Phone notifications require a written follow-up report.

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Attachment 3 - Emission Inventory Form

ADEC Reporting Form **Emission Inventory Reporting** **State of Alaska Department of Environmental Conservation** **Division of Air Quality**	**Emission Inventory Year- [ ]**
Mandatory information is highlighted in bright yellow. Make additional copies as needed.	

Stationary Source Detail		
Inventory start date		
Inventory end date		
ADEC ID or Permit Number		
EPA ID:		
Census Area/ Community		
Facility Name		
Facility Physical Location	**Address:**	
	City, State, Zip Code:	
	Latitude:	**Longitude:**
	Legal Description:	
Owner Name & Address & contact number	**Owner Name:**	
	Owner Address:	
	Phone Number:	
Mailing Contact Information	**Mailing Address:**	
Line of Business (NAICS)		
Line of Business (SIC)		
Facility Status:		

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Emissions Unit Data			
Specifications			
ID		**Design Capacity**	
Description			
Emissions Unit Status			
Manufacturer		**Manufactured Year**	
Model Number		**Serial Number**	
Regulations			
Regulation/Description:			
Control Equipment (List All if applicable):			
ID			
System Description	-		
Equipment Type(s)			
Manufacturer			
Model			
Control Efficiency (%)			
Capture Efficiency (%)			
Pollutants Controlled		**Reduction Efficiency (%):**	
		Reduction Efficiency (%):	

Processes	
Process	**Primary Process**
SCC Code	(ex. 20100201)
	>
	>
	>
	>
Material Processed	
Period Start	
Period End	
Throughput (units)	
Summer %	
Fall %	
Winter %	
Spring %	
Operational Schedule	
Days/Week	
Hours/Day	
Weeks/Year	
Hours/Year	

Fuel Characteristics			
Heat Content	Elem. Sulfur Content (%)	H2S Sulfur Content	Ash Content (if applicable)
Heating			
Heat Input	Heat Output	Heat Values Convention	

Emissions Operating Type:					
Pollutant	Emission Factor (EF)	EF Numerator	EF Denominator	EF Origin	Tons
Carbon Monoxide (CO)					
Nitrogen Oxides NOx					
PM_{10} Primary (PM_{10}-PRI)					
$PM_{2.5}$ Primary (PM_{25}-PRI)					
Sulfur Dioxide (SO_2)					
Ammonia (NH_3)					
Lead and lead compounds					
Volatile Organic Compounds (VOC)					
Emissions' Release Point					
Release Point ID					
Apportion%					

Process	Secondary Process
SCC Code	(ex. 20100201)
	>
	>
	>
	>
Material Processed	
Period Start	
Period End	
Throughput (units)	
Summer %	
Fall %	
Winter %	
Spring %	
Operational Schedule	
Days/Week	
Hours/Day	
Weeks/Year	
Hours/Year	

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Fuel Characteristics			
Heat Content	Elem. Sulfur Content (%)	H2S Sulfur Content	Ash Content (if applicable)

Heating		
Heat Input	Heat Output	Heat Values Convention

Emissions Operating Type:					
Pollutant	Emission Factor (EF)	EF Numerator	EF Denominator	EF Origin	Tons
Carbon Monoxide (CO)					
Nitrogen Oxides NOx					
PM_{10} Primary (PM_{10}-PRI)					
$PM_{2.5}$ Primary (PM_{25}-PRI)					
Sulfur Dioxide (SO_2)					
Ammonia (NH_3)					
Lead and lead compounds					
Volatile Organic Compounds (VOC)					
Emissions' Release Point					
Release Point ID					
Apportion%					

Stack Detail (Release Point)	
> Specifications	
ID	
Type	
Description	
Stack Status	
> Stack Parameters	
Stack Height (ft)	
Stack Diameter (ft)	
Exit Gas Temp (F)	
Exit Gas Velocity (fps)	
Exit Gas Flow Rate	
> Geographic Coordinate	
Latitude	
Longitude	

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Datum	
Accuracy (meters)	
Base Elevation (meters)	

Certification:

Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.

Printed Name:_____Title_____Date _____

Signature:_____ Phone number_____

NOTE: *This document must be certified in accordance with 18 AAC 50.345(j)*

To submit this report:

1. Department's Air Online Services using the Permittee Portal option:
   http://dec.alaska.gov/applications/air/airtoolsweb
   Or
2. Fax to: 907-269-7508
   Or
3. Email to: DEC.AQ.Airreports@alaska.gov
   Or
4. Mail to: ADEC Division of Air Quality
   ATTN: Emissions Inventory
   555 Cordova Street
   Anchorage, AK 99501

ED_013256A_00006673-00060

Technical Analysis Report

For the terms and conditions of
Construction Permit AQ1539CPT01

Issued to Alaska Gasline Development Corporation

For the Liquefaction Plant

Alaska Department of Environmental Conservation
Air Permits Program

Prepared by Dave Jones
Reviewed by Aaron Simpson

Final – July 7, 2022

1. INTRODUCTION

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

1.1. Description of Source

The Liquefaction Plant is a new stationary source located in Southcentral Alaska's Kenai Peninsula, approximately 3 miles southwest of Nikiski and 8.5 miles north of Kenai. The facility is classified under Standard Industrial Classification code 4922 for natural gas transmission and under North American Industrial Classification code 488999 for All Other Support Activities for Transportation (Liquefied Natural Gas Plants).

1.2. Application Description

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

1.3. Project Description

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

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

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

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A description of the process is as follows:

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

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

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

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

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

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

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

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

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

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

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

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

2. CLASSIFICATION FINDINGS

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

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1. This project is classified under 18 AAC 50.306(a) for beginning actual construction of a new stationary source that is PSD major for NOx, CO, VOC, PM, PM-10, PM-2.5, SO_2, and GHG.
2. This project is also classified under 18 AAC 50.316 as a major source of HAPs for formaldehyde and ethylbenzene.

3. APPLICATION REVIEW FINDINGS

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

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

4. EMISSIONS SUMMARY AND PERMIT APPLICABLITY

Table 11 shows the emissions summary and permit applicability with assessable emissions from the stationary source, listed in tons per year (tpy). Emission factors and detailed calculations are provided in Appendix A.

A summary of the potential to emit (PTE) and assessable PTE, as determined by the Department, is shown in Table 11 below.

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Table 11: Emissions Summary and Permit Applicability

Parameter	Emissions (tpy)					
	NOx	CO	VOC	PM-2.5	PM-10	SO_2
PTE Authorized Under AQ1539CPT01	2,793.4	11,891.2	24,657.2	1,303.3	1,303.3	182.8
Title V Permit Thresholds	100	100	100	100	100	100
Title V Permit Required?	Yes	Yes	Yes	Yes	Yes	Yes
Assessable Emissions	2,793	11,891	24,657	1,303	1,303	183
	40,827					

Table Notes:
40,827 tons is a conservative estimate that includes flaring at maximum capacity for 1,000 hours per year combined for the wet flares, 1,000 hours per year combined for the dry flares, and 144 hours per year for the low pressure flare. Without the inclusion of maximum flaring the total assessable emissions is 1,297 tons.
PM-10 emissions include PM-2.5 emissions. Therefore, PM-2.5 is not counted in total assessable emissions.
Fuel Gas Sulfur Content: 16 ppmv used for calculating SO_2 emissions from all gas-fired EUs.
Diesel Fuel Sulfur Content: 15 ppmw used for calculating SO_2 emissions from all diesel-fired EUs

Table 12: Major Source and PSD Review Applicability

Parameter	NOx	CO	VOC	PM-2.5	PM-10	PM	SO_2	CO_2e[1]
PTE for AQ1539CPT01 excluding fugitive emissions	2,793.4	11,891.2	24,657.2	1,303.3	1,303.3	1,303.3	182.8	8,572,968
PSD Major Source Threshold	250	250	250	250	250	250	250	N/A
Major Source Triggered?	Yes	Yes	Yes	Yes	Yes	Yes	No	No
PSD Significant Emissions Rates	40	100	40[3]	10[2]	15	25	40	75,000
PSD Review Triggered?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

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

5. PERMIT CONDITIONS

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

Section 1: Emissions Unit Inventory

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

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Section 2: Emission Fees

Condition 3, Fee Requirements

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

Conditions 4 and 5, Assessable Emissions

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

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

Section 3: State Emission Standards

Condition 6, Visible Emissions

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

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

Conditions 7, Particulate Matter (PM)

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

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

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Condition 8, Sulfur Compound Emissions

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

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

Section 4: Ambient Air Quality Protection Requirements

Conditions 9 – 12

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

Section 5: Best Available Control Technology

Conditions 13 – 18

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

Section 6: General Recordkeeping, Reporting, and Certification Requirements

Condition 19, Certification

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

Condition 20, Submittals

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

Condition 21, Information Requests

AS 46.14.020(b) allows the Department to obtain a wide variety of emissions, design and operational information from the owner and operator of a stationary source. This statutory

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provision is reiterated as a standard permit condition in 18 AAC 50.345(i). The Department used the standard language in Construction Permit AQ1539CPT01.

Condition 22, Recordkeeping Requirements

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

Condition 23, Excess Emission and Permit Deviation Reports

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

Condition 24, Operating Reports

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

Condition 25, Air Pollution Prohibited

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

Condition 26, Emission Inventory Reporting

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

Section 7: Standard Permit Conditions

Conditions 27 – 32

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

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

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

Section 8: General Source Test Requirements

Conditions 33 – 39

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

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

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

6. PERMIT ADMINISTRATION

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

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Appendix A: Emissions Calculations

Table 13 presents details of the EUs, their characteristics, and emissions. Potential emissions are estimated using maximum annual operation for all fuel burning equipment as defined in 18 AAC 50.990(39) subject to any operating limits.

Table 13: Detailed Permanent EU Inventory and Potential to Emit (tpy)

EU ID	Emissions Unit Description	Rating		Annual Operating Hours	NOx CO EF Units	NO_x		CO		VOC PM-2.5 PM-10 EF Units	VOC		PM_{10}		$PM_{2.5}$		SO_2	CO_2e
						EF	tpy	EF	tpy		EF	tpy	EF	tpy	EF	tpy	tpy	1,000 tpy
1[1]	Train 1a Simple Cycle Treated Gas Compressor Turbine	1,113	MMBtu/hr	8760	ppmv	2	35.42	5	54.04	lb/MMBtu	2 ppmv	13.73	0.0070	34.29	0.0070	34.29	12.15	570.84
2[1]	Train 1b Simple Cycle Treated Gas Compressor Turbine	1,113	MMBtu/hr	8760	ppmv	2	35.42	5	54.04	lb/MMBtu	2 ppmv	13.73	0.0070	34.29	0.0070	34.29	12.15	570.84
3[1]	Train 2a Simple Cycle Treated Gas Compressor Turbine	1,113	MMBtu/hr	8760	ppmv	2	35.42	5	54.04	lb/MMBtu	2 ppmv	13.73	0.0070	34.29	0.0070	34.29	12.15	570.84
4[1]	Train 2b Simple Cycle Treated Gas Compressor Turbine	1,113	MMBtu/hr	8760	ppmv	2	35.42	5	54.04	lb/MMBtu	2 ppmv	13.73	0.0070	34.29	0.0070	34.29	12.15	570.84
5[1]	Train 3a Simple Cycle Treated Gas Compressor Turbine	1,113	MMBtu/hr	8760	ppmv	2	35.42	5	54.04	lb/MMBtu	2 ppmv	13.73	0.0070	34.29	0.0070	34.29	12.15	570.84
6[1]	Train3b Simple Cycle Treated Gas Compressor Turbine	1,113	MMBtu/hr	8760	ppmv	2	35.42	5	54.04	lb/MMBtu	2 ppmv	13.73	0.0070	34.29	0.0070	34.29	12.15	570.84
7[2]	Power Generation Turbines	384	MMBtu/hr	8760	ppmv	2	11.99	2	7.28	lb/MMBtu	2 ppmv	4.63	0.0070	11.83	0.0070	11.83	4.19	196.95
8[2]	Power Generation Turbines	384	MMBtu/hr	8760	ppmv	2	11.99	2	7.28	lb/MMBtu	2 ppmv	4.63	0.0070	11.83	0.0070	11.83	4.19	196.95
9[2]	Power Generation Turbines	384	MMBtu/hr	8760	ppmv	2	11.99	2	7.28	lb/MMBtu	2 ppmv	4.63	0.0070	11.83	0.0070	11.83	4.19	196.95
10[2]	Power Generation Turbines	384	MMBtu/hr	8760	ppmv	2	11.99	2	7.28	lb/MMBtu	2 ppmv	4.63	0.0070	11.83	0.0070	11.83	4.19	196.95
11[3]	Diesel Firewater Pump Engine	575	hp	500	g/hp-hr	3.56	1.13	3.25	1.03	g/hp-hr	0.19	0.059	0.19	0.059	0.19	0.059	0.0014	0.16
12[4]	Auxiliary Air Compressor Engine	300	hp	500	g/hp-hr	0.45	0.074	3.26	0.54	g/hp-hr	0.21	0.035	0.022	0.004	0.022	0.004	0.0007	0.086
13[5]	Thermal Oxidizer	6.0	MMBtu/hr	8760	g/hp-hr	0.55	1.45	0.082	2.17	g/hp-hr	0.0054	0.14	0.0075	0.20	0.0075	0.20	0.072	3.08
14[6]	Dry Ground Flare #1 (Pilot/Purge)	7.15	MMBtu/hr	8760	lb/MMBtu	0.068	2.13	0.31	9.71	lb/MMBtu	0.66	20.67	0.028	0.88	0.028	0.88	0.076	3.67
	Dry Ground Flare #1 (Maximum)	59,992	MMBtu/hr	500	lb/MMBtu	0.068	1,019.86	0.31	4,649.38	lb/MMBtu	0.66	9,898.68	0.028	423.25	0.028	423.25	37.38	1,756.22
15[6]	Wet Ground Flare #1 (Pilot/Purge)	2.25	MMBtu/hr	8760	lb/MMBtu	0.068	0.67	0.31	3.06	lb/MMBtu	0.66	6.50	0.028	0.28	0.028	0.28	0.025	1.15
	Wet Ground Flare #1 (Maximum)	14,020	MMBtu/hr	500	lb/MMBtu	0.068	238.34	0.31	1,086.55	lb/MMBtu	0.66	2,313.30	0.028	98.91	0.028	98.91	8.74	410.43
16[6]	Dry Ground Flare #2 (Pilot/Purge)	7.15	MMBtu/hr	8760	lb/MMBtu	0.068	2.13	0.31	9.71	lb/MMBtu	0.66	20.67	0.028	0.88	0.028	0.88	0.076	3.67

	Dry Ground Flare #2 (Maximum)	59,992	MMBtu/hr	500	lb/MMBtu	0.068	1,019.86	0.31	4,649.38	lb/MMBtu	0.66	9,898.68	0.028	423.25	0.028	423.25	37.38	1,756.22
17[6]	Wet Ground Flare #2 (Pilot/Purge)	2.25	MMBtu/hr	8760	lb/MMBtu	0.068	0.67	0.31	3.06	lb/MMBtu	0.66	6.50	0.028	0.28	0.028	0.28	0.025	1.15
	Wet Ground Flare #2 (Maximum)	14,020	MMBtu/hr	500	lb/MMBtu	0.068	238.34	0.31	1,086.55	lb/MMBtu	0.66	2,313.30	0.028	98.91	0.028	98.91	8.74	410.43
18[6]	Dry Ground Flare #3 (Pilot/Purge)	7.15	MMBtu/hr	0	N/A													
	Dry Ground Flare #3 (Maximum)	59,992	MMBtu/hr	0	N/A													
19[6]	Wet Ground Flare #3 (Pilot/Purge)	2.25	MMBtu/hr	0	N/A													
	Wet Ground Flare #3 (Maximum)	14,020	MMBtu/hr	0	N/A													
20[6]	Elevated LP Flare (Pilot/Purge)	10.5	MMBtu/hr	8760	lb/MMBtu	0.068	3.13	0.31	14.26	lb/MMBtu	0.66	30.35	0.028	1.30	0.028	1.30	0.22	5.39
	Elevated LP Flare (Maximum)	997.5	MMBtu/hr	144	lb/MMBtu	0.068	5.14	0.31	22.42	lb/MMBtu	0.66	47.40	0.028	2.03	0.028	2.03	0.20	8.77
21[7]	Gas Condensate Storage Tank	457,890	gal	N/A	N/A													
22[7]	Off-Spec Gas Condensate Storage Tank	126,904	gal	N/A	N/A													
23[7]	Gas Condensate Loading System	1,000	gal	N/A	N/A													
24 – 26[8]	Diesel Storage Tanks	4,204	gal (total)	N/A	N/A							0.0015						
N/A	Other Fugitive Emissions	N/A	N/A	N/A	N/A							17.96						2.39
Total Emissions (Without Maximum Flare)							**277.0**		**419.3**			**251.2**		**259.0**		**259.0**	**90.6**	**4,242.31**
Total Emissions (With Maximum Flare)							**2,793.4**		**11,891.2**			**24,657.2**		**1,303.3**		**1,303.3**	**182.8**	**8,572.97**

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

[6] NOx EF from AP-42 Table 13.5-1. PM-10, and PM-2.5 EFs from AP-42 Table 13.5-1 for soot (lightly smoking flare). CO and VOC EF from AP-42 Table 13.5-1. The Permittee has three dry flares EUs 14, 16, and 18 and three wet flares EUs 15, 17, and 19 for redundancy, but only two of each type of flare operate at any given time. Condition 17.2 limits the flares to 1,000 hours combined for each type of flare and the table expresses this with 500-hour limits on each of EUs 14 – 17 and no emissions for EUs 18 and 19.
[7] Emissions from the condensate storage tanks and loading system are captured and routed to the thermal oxidizer EU 13.
[8] VOC PTE calculated using EPA's Tanks software.

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Appendix B: Best available Control Technology

1.0 INTRODUCTION

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

2.0 BACT EVALUATION

A BACT analysis is an evaluation of all available control options for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts. 40 C.F.R. 52.21(b)(12) defines BACT as a site-specific determination on a case-by-case basis. The Department's goal is to identify BACT for the permanent emission units (EUs) at the Liquefaction Plant that emit CO, NOx, SO_2, particulates, VOC, and GHG, establish emission limits which represent BACT, and assess the level of monitoring, recordkeeping, and reporting requirements (MR&Rs) necessary to ensure AGDC applies BACT for the EUs. The Department based the BACT review on the five-step top-down approach set forth in Federal Register Volume 61, Number 142, July 23, 1996 (Environmental Protection Agency). Table 2-1 presents the EUs subject to BACT review.

Table 2-1: EUs Subject to BACT Review

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

Five-Step BACT Determinations

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

Step 1 Identify All Potentially Available Control Options

The Department identifies all available control options for the EUs and the pollutant under consideration. This includes technologies used throughout the world or emission reductions through the application of available control techniques, changes in process design, and/or operational limitations. To assist in identifying available controls, the Department reviews available controls listed on the Reasonably Available Control Technology (RACT), BACT, and Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC). The RBLC is an EPA database where permitting agencies nationwide post imposed BACT for PSD sources. It is

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usually the first stop for BACT research. In addition to the RBLC search, the Department used several search engines to look for emerging and tried technologies used to control NOx, CO, SO_2, Particulates, VOC, and GHG emissions from equipment similar to those listed in Table 2-1.

Step 2 Eliminate Technically Infeasible Control Options:
The Department evaluates the technical feasibility of each control option based on source specific factors in relation to each EU subject to BACT. Based on sound documentation and demonstration, the Department eliminates control options deemed technically infeasible due to physical, chemical, and engineering difficulties.

Step 3 Rank Remaining Control Technologies by Control Effectiveness
The Department ranks the remaining control options in order of control effectiveness with the most effective at the top.

Step 4 Evaluate the Most Effective Controls and Document the Results as Necessary
The Department reviews the detailed information in the permit application about the control efficiency, emission rate, emission reduction, cost, environmental, and energy impacts for each option to decide the final level of control. The applicant must present an objective evaluation of both the beneficial and adverse energy, environmental, and economic impacts. An applicant proposing to use the most effective option does not need to provide the detailed information for the less effective options. If cost is not an issue, a cost analysis is not required.

Cost effectiveness for a control option is defined as the total net annualized cost of control divided by the tons of pollutant removed per year. Annualized cost includes annualized equipment purchase, erection, electrical, piping, insulation, painting, site preparation, buildings, supervision, transportation, operation, maintenance, replacement parts, overhead, raw materials, utilities, engineering, start-up costs, financing costs, and other contingencies related to the control option.

Step 5 Select BACT
The Department selects the most effective control option not eliminated in Step 4 as BACT for the pollutant and EU under review. The Department lists the final BACT requirements determined for each EU in this step. A project may achieve emission reductions through the application of available technologies, changes in process design, and/or operational limitations. The Department reviewed Liquefaction Plant's BACT analysis and made BACT determinations for NOx, CO, SO_2, Particulates, VOC, and GHG for various EUs based on the information submitted by AGDC in their application, information from vendors, suppliers, sub-contractors, RBLC, and a comprehensive internet search.

3.0 COMPRESSOR TURBINES

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

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3.1 NOx

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

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

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

Step 1 – Identify NOx Control Technologies for Compressor Turbines

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

(a) Selective Catalytic Reduction (SCR)
SCR is a post-combustion gas treatment technique for reducing nitric oxide (NO) and nitrogen dioxide (NO_2) in the turbine exhaust stream to molecular nitrogen (N_2), water, and oxygen (O_2). In the SCR process, aqueous or anhydrous ammonia (NH_3) is injected into the flue gas upstream of a catalyst bed. The catalyst lowers the activation energy of the NOx decomposition reaction. NOx and NH_3 combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental N_2 and water. The operating temperature of conventional SCR systems ranges from 400 degrees Fahrenheit (°F) to 800°F. High temperature SCR relies on special material reaction grids and can operate at higher temperature ranges between 700°F to 1,075°F. High temperature SCR is most frequently installed on simple cycle turbines. Depending on the overall NH_3-to-NOx ratio, removal efficiencies are generally 80 to 90 percent. The Department considers SCR a technically feasible control technology for large simple cycle gas-fired turbines.

(b) Dry Low NOx (DLN)
DLN combustors (marketed under many similar names such as SoLoNOx or DLE) utilize multistage premix combustors where the air and fuel is mixed at a lean (high oxygen) fuel-to-air ratio. The excess air in the lean mixture acts as a heat sink, which lowers peak combustion temperatures and also ensures a more homogeneous mixture avoiding localized "hot spots", both resulting in greatly reduced NOx formation rates. DLN combustors have the potential to reduce NOx emissions by 40 to 60%. In the Department's search of the RBLC database, the majority of large simple cycle natural gas-fired combustion turbines used DLN as the primary control method for NOx emissions and contained a BACT limit of 9 parts per million by volume dry (ppmvd). Note that DLN is designed for natural gas-fired or dual-fuel fired units and is not effective in controlling NOx emissions from fuel oil-fired units. The Department considers DLN a technically feasible control technology for large simple cycle gas-fired turbines.

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(c) Water/Steam Injection (ULSD)
Water/steam injection involves the introduction of water or steam into the combustion zone. The injected fluid provides a heat sink which absorbs some of the heat of reaction, causing a lower flame temperature. The lower flame temperature results in lower thermal NOx formation. Both steam and water injections are capable of obtaining the same level of control. The process requires approximately 0.8 to 1.0 pound of water or steam per pound of fuel burned. The main technical consideration is the required purity of the water or steam, which is required to protect the equipment from dissolved solids. Obtaining water or steam of sufficient purity requires the installation of rigorous water treatment and deionization systems, incurring additional costs. Water/steam injection also increases CO emissions as it lowers the combustion temperature. Depending on baseline uncontrolled NOx levels, water or steam injection can reduce NOx by 60% or more. Water/steam injection is a proven technology for NOx emissions reduction from turbines. The Department considers water/steam injection a technically feasible control technology for large simple cycle gas-fired turbines.

(d) Selective Non-Catalytic Reduction (SNCR)
SNCR involves the non-catalytic decomposition of NOx in the flue gas to N_2 and water using reducing agents such as urea or NH_3. The process utilizes a gas phase homogeneous reaction between NOx and the reducing agent within a specific temperature window. The reducing agent must be injected into the flue gas at a location in the unit that provides the optimum reaction temperature and residence time. The NH_3 process (trade name-Thermal DeNOx) requires a reaction temperature window of 1,600°F to 2,200°F. In the urea process (trade name–NO_xOUT), the optimum temperature ranges between 1,600 °F and 2,100 °F. Because the temperature of simple cycle turbines exhaust gas normally ranges from 800°F to 1,000°F, achieving the required reaction temperature is the main difficulty for application of SNCR to turbines. The Department's research did not identify SNCR as a technology used to control NOx emissions from turbines installed at any facility. Hence the Department considers SNCR as a technically infeasible control technology for the large simple cycle gas-fired turbines.

(e) Non-Selective Catalytic Reduction (NSCR)
NSCR simultaneously reduces NOx and oxidizes CO and hydrocarbons in the exhaust gas to N_2, carbon dioxide (CO_2), and water. The catalyst, usually a noble metal, causes the reducing gases in the exhaust stream (hydrogen, methane, and CO) to reduce both NO and NO_2 to N_2 at a temperature between 800°F and 1,200°F. NSCR requires a low excess O_2 concentration in the exhaust gas stream to be effective because the O_2 must be depleted before the reduction chemistry can proceed. NSCR is only effective with rich-burn gas-fired units that operate at all times with an air/fuel ratio controller at or close to stoichiometric conditions. Turbines operate under conditions far more fuel-lean than required to support NSCR. The Department's research did not identify NSCR as a control technology used to control NOx emissions from turbines installed at any facility. Hence the Department considers NSCR as a technically infeasible control technology for the large simple cycle gas-fired turbines.

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

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

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

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

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

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

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

Applicant Proposal
AGDC proposed to install the two most stringent control technologies SCR with DLN combustors as BACT for NOx emissions. NOx emissions from the large simple cycle gas-fired turbines will not exceed 2 ppmvd @ 15% O_2.

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

(a) NOx emissions from EUs 1 – 6 shall be controlled by operating and maintaining selective catalytic reduction at all times the units are in operation (except for the 40 hours per year allowed for each EU under the permit);

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

(c) NOx emissions from EUs 1 – 6 shall not exceed 2 ppmvd @ 15% O_2 averaged over a 3-hour period; and

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

3.2 CO
Possible CO emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.110: large simple cycle natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 3-2.

Table 3-2: CO Control for Large Simple Cycle Natural Gas-Fired Combustion Turbines

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

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

(a) CO Oxidation Catalyst

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

(b) Good Combustion Practices (GCP) and Clean Fuel
GCP typically include the following elements:

1. Sufficient residence time to complete combustion;
2. Providing and maintaining proper air/fuel ratio;
3. High temperatures and low oxygen levels in the primary combustion zone;
4. High enough overall excess oxygen levels to complete combustion and maximize thermal efficiency;
5. Proper fuel gas supply system designed to minimize effects of contaminants or fluctuations in pressure and flow on the fuel gas delivered.

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

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

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

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identify NSCR as a control technology used to control CO emissions from turbines installed at any facility in the RBLC database. Therefore, the Department considers NSCR a technically infeasible control technology for the large simple cycle gas-fired turbines.

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

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

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

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

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

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

Department Evaluation of BACT for CO Emissions from Compressor Turbines
AGDC initially proposed to install oxidation catalyst with an emission rate of 10 ppmvd @ 15% O_2, which would match the highest value found in the RBLC for CO emissions from large simple cycle turbines. This emission rate was set in a July 2010 permit for the Pueblo Airport Generating Station (RBLC ID No. CO-0073). The Department finds that a newly constructed simple cycle turbine with oxidation catalyst controls would be able to achieve a lower emission rate than what was proposed by AGDC. The Department instead selected 5 ppmvd @ 15% O_2 for the CO emission limit after examining emission limits in the RBLC for all large simple cycle turbines using oxidation catalysts. This RBLC search returned results ranging from 1.5 ppmvd at 15% O_2 to 10 ppmvd at 15% O_2 with a median and mode of 6 ppmvd at 15% O_2. The case of the 1.5 ppmvd at 15% O_2 determination was for turbines that were also meeting a Least Achievable Control Technology (LAER) limit for VOCs and was located in Maryland. There were two cases of turbines at power generating facilities in Maryland and New York that had CO limits of 2 ppmvd at 15% O_2. However, the simple cycle turbines at the Liquefaction Plant will drive refrigeration compressors and operate over a wider range of operating conditions than the steady-

state power generation turbines in the RBLC. Therefore, the Department agrees that slightly higher CO limits are justified given the cyclical nature of the operating conditions and harsher and colder environment in Alaska.

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

(a) CO emissions from EUs 1 – 6 shall be controlled by operating and maintaining an oxidation catalyst at all times the units are in operation (except for the 40 hours per year allowed for each EU under the permit);

(b) CO emissions from EUs 1 – 6 shall be controlled by following good combustion practices at all times the units are in operation;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(d) Particulate emissions from EUs 1 – 6 shall not exceed 10 percent opacity averaged over any six consecutive minutes; and

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

3.4 SO_2
Possible SO_2 emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.110: large simple cycle natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 3-4.

Table 3-4: SO_2 Control for Large Simple Cycle Natural Gas-Fired Combustion Turbines

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Control Technology	Number of Determinations	Emission Limits[12](Sulfur in Fuel)
Good Combustion & Clean Fuel	8	1 – 2 gr/100 dscf 16.9 – 33.8 ppmv
No Control	2	1 – 2 gr/100 dscf 16.9 – 33.8 ppmv

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

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

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

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

Step 4 – Evaluate the Most Effective Controls
According to the RBLC clean fuels and good combustion practices are the applicable controls for SO_2 emissions for EUs 1 – 6. Since these are not add-on controls, there are no additional environmental impacts.

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

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

Step 5 – Selection of SO_2 BACT for Compressor Turbines

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

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The Department's finding is that BACT for SO_2 emissions from the simple cycle gas-fired combustion turbines greater than 25 MW is as follows:

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

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

3.5 VOC

Possible VOC emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.110: large simple cycle natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 3-5.

Table 3-5: VOC Control for Large Simple Cycle Natural Gas-Fired Combustion Turbines

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

Step 1 – Identify VOC Control Technologies for Compressor Turbines

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

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

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

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

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

Step 3 – Rank Remaining VOC Control Options for Compressor Turbines

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

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

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

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

Applicant Proposal
AGDC proposed to install an oxidation catalyst and use good combustion practices for the compressor turbines EUs 1 – 6 as BACT for reducing VOC emissions. VOC emissions from EUs 1 – 6 will not exceed 2 ppmvd at 15% O_2 which matches the lowest emission rate in the RBLC for large simple cycle turbines equipped with oxidation catalysts.

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

(a) VOC emissions from EUs 1 – 6 shall be controlled by operating and maintaining an oxidation catalyst at all times the units are in operation (except for the 40 hours per year allowed for each EU under the permit);
(b) VOC emissions from EUs 1 – 6 shall be controlled by following good combustion practices at all times the units are in operation;
(c) VOC emissions from EUs 1 – 6 shall not exceed 2 ppmvd at 15% O_2 averaged over a 3-hour period; and
(d) Initial compliance with the proposed VOC emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

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

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

Control Technology	Number of Determinations	Emission Limits
Good Combustion & Clean Fuel	11	884 – 1,707 lb/MWh

		117.0 – 120.0 lb/MMBtu
Carbon Capture and Sequestration (CCS)	0	N/A
No Control	10	1030 – 1,461 lb/MWh

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

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

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

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

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

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

4. Organic Rankine Cycle (ORC)
   ORC uses a refrigerant working fluid that is heated by engine exhaust gas from the natural gas fired turbines, and expands through a turbine connected to the engine shaft. The ORC system involves the same components as in a conventional steam power plant; however, instead of using water as a working fluid, ORC uses a refrigerant with a boiling point lower than that of water, and enables recovery of heat from lower-temperature heat sources. The ORC offers reduced equipment size compared to the steam cycle. This equipment is at their best in air-cooled applications where the heat source is below approximately 400°F. The heat source for this application is the gas turbine exhaust, and is approximately 800 to 1,000 °F, 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 40°F (approximately 50% of the year) makes the system less efficient. Also, additional heat exchangers may be needed to preheat the ORC working fluid and the combustion air, which would increase the cost and complexity of the system. The Department does not consider ORC as a technically feasible technology for control of GHGs.

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

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

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combustion techniques using air and carbon-containing fuels in order to isolate CO_2 from the combustion exhaust gases.

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

The Department's research did not identify CCS as a control technology used to control GHG emissions from turbines installed at any facility in the RBLC database. Additionally, the Department contacted the Alaska Department of Natural Resources (DNR) who stated that, as of July 1, 2022, "At this time, the state does not have the regulatory framework to permit the leasing of its lands for CCS projects." Thus there is no viable CCS facility within reasonable proximity for internment of CO_2 sequestration. Therefore, the Department finds that for the Liquefaction Plant, the installation of CCS to compress, transport, and inject CO_2 is not technologically feasible.

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

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

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

Aeroderivative turbine: the facility is currently designed to use six simple cycle turbines as the mechanical drivers for the refrigeration process of the natural gas. Requiring the compressor

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turbines to be aeroderivative models would fundamentally redefine the project, and is therefore not considered as an option in the BACT analysis.

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

(a) GCP and Clean Fuels (<40% Control)

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

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

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

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

(a) GHG emissions from EUs 1 – 6 shall be minimized by maintaining good combustion practices and burning clean fuels (natural gas) at all times the units are in operation; and
(b) GHG emissions from EUs 1 – 6 shall not exceed 117.1 lb/MMBtu averaged over a 3-hour period.

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

4.1 NOx
Possible NOx emission control technologies for turbines were obtained from the RBLC. The

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

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

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

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

(a) Selective Catalytic Reduction (SCR)
SCR is a post-combustion gas treatment technique for reducing nitric oxide (NO) and nitrogen dioxide (NO_2) in the turbine exhaust stream to molecular nitrogen (N_2), water, and oxygen (O_2). In the SCR process, aqueous or anhydrous ammonia (NH_3) is injected into the flue gas upstream of a catalyst bed. The catalyst lowers the activation energy of the NOx decomposition reaction. NOx and NH_3 combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental N_2 and water. The operating temperature of conventional SCR systems ranges from 400 degrees Fahrenheit (°F) to 800°F. High temperature SCR relies on special material reaction grids and can operate at higher temperature ranges between 700°F to 1,075°F. High temperature SCR is most frequently installed on simple cycle turbines. Depending on the overall NH_3-to-NOx ratio, removal efficiencies are generally 80 to 90 percent. In the Department's search of the RBLC database, the majority of large combined cycle natural gas-fired combustion turbines used SCR as the primary control method for NOx emissions and contained a BACT limit of 2 ppmv. Hence, the Department considers SCR a technically feasible control technology for large combined cycle gas-fired turbines.

(b) Dry Low NOx (DLN)
DLN combustors (marketed under many similar names such as SoLoNOx or DLE) utilize multistage premix combustors where the air and fuel is mixed at a lean (high oxygen) fuel-to-air ratio. The excess air in the lean mixture acts as a heat sink, which lowers peak combustion temperatures and also ensures a more homogeneous mixture avoiding localized "hot spots", both resulting in greatly reduced NOx formation rates. DLN combustors have the potential to reduce NOx emissions by 40 to 60%. Note that DLN is designed for natural gas-fired or dual-fuel fired units and is not effective in controlling NOx emissions from fuel oil-fired units. The Department considers DLN a technically feasible control technology for large combined cycle gas-fired turbines.

(c) Water/Steam Injection
Water/steam injection involves the introduction of water or steam into the combustion zone. The injected fluid provides a heat sink which absorbs some of the heat of reaction, causing a lower flame temperature. The lower flame temperature results in lower thermal NOx formation. Both steam and water injections are capable of obtaining the same level

of control. The process requires approximately 0.8 to 1.0 pound of water or steam per pound of fuel burned. The main technical consideration is the required purity of the water or steam, which is required to protect the equipment from dissolved solids. Obtaining water or steam of sufficient purity requires the installation of rigorous water treatment and deionization systems, incurring additional costs. Water/steam injection also increases CO emissions as it lowers the combustion temperature. Depending on baseline uncontrolled NOx levels, water or steam injection can reduce NOx by 60% or more. Generally speaking the Department considers water/steam injection a technically feasible control technology for large combined cycle gas-fired turbines. However, the base model turbine selected by ADGC already comes equipped with DLN technology which is not compatible with water/steam injection, and has lower NOx emission rates than water/steam injection. Additionally, the Department's research did not identify water/steam injection as a technology used to control NOx emissions from large combined cycle turbines installed at any facility in the RBLC database. Hence the Department considers water/steam injection as a technically infeasible control technology for the large combined cycle gas-fired turbines.

(d) Selective Non-Catalytic Reduction (SNCR)
SNCR involves the non-catalytic decomposition of NOx in the flue gas to N_2 and water using reducing agents such as urea or NH_3. The process utilizes a gas phase homogeneous reaction between NOx and the reducing agent within a specific temperature window. The reducing agent must be injected into the flue gas at a location in the unit that provides the optimum reaction temperature and residence time. The NH_3 process (trade name-Thermal DeNOx) requires a reaction temperature window of 1,600°F to 2,200°F. In the urea process (trade name–NO_xOUT), the optimum temperature ranges between 1,600 °F and 2,100 °F. Because the temperature of combined cycle turbines exhaust gas normally ranges from 800°F to 1,000°F, achieving the required reaction temperature is the main difficulty for application of SNCR to turbines. The Department's research did not identify SNCR as a technology used to control NOx emissions from turbines installed at any facility. Hence the Department considers SNCR as a technically infeasible control technology for the large combined cycle gas-fired turbines.

(e) Non-Selective Catalytic Reduction (NSCR)
NSCR simultaneously reduces NOx and oxidizes CO and hydrocarbons in the exhaust gas to N_2, carbon dioxide (CO_2), and water. The catalyst, usually a noble metal, causes the reducing gases in the exhaust stream (hydrogen, methane, and CO) to reduce both NO and NO_2 to N_2 at a temperature between 800°F and 1,200°F. NSCR requires a low excess O_2 concentration in the exhaust gas stream to be effective because the O_2 must be depleted before the reduction chemistry can proceed. NSCR is only effective with rich-burn gas-fired units that operate at all times with an air/fuel ratio controller at or close to stoichiometric conditions. Turbines operate under conditions far more fuel-lean than required to support NSCR. The Department's research did not identify NSCR as a control technology used to control NOx emissions from turbines installed at any facility. Hence the Department considers NSCR as a technically infeasible control technology for the large combined cycle gas-fired turbines.

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

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

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

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

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

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

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

Applicant Proposal
AGDC proposed to install the two most stringent control technologies SCR with DLN combustors as BACT for NOx emissions. NOx emissions from the large combined cycle gas-fired turbines will not exceed 2 ppmvd @ 15% O_2.

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

(a) NOx emissions from EUs 7 – 10 shall be controlled by operating and maintaining selective catalytic reduction at all times the units are in operation (except for the 40 hours per year allowed for each EU under the permit);

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

(b) NOx emissions from EUs 7 – 10 shall not exceed 2 ppmvd @ 15% O_2 averaged over a 3-hour period; and

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

4.2 CO
Possible CO emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.210: large combined cycle and cogeneration natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 4-2.

Table 4-2: CO Control for Large Combined Cycle Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits (ppmv)
Oxidation Catalyst	78	0.9 – 15
Good Combustion & Clean Fuel	17	2 – 50

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

(a) CO Oxidation Catalyst

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

(b) Good Combustion Practices (GCP) and Clean Fuel
GCP typically include the following elements:

1. Sufficient residence time to complete combustion;
2. Providing and maintaining proper air/fuel ratio;
3. High temperatures and low oxygen levels in the primary combustion zone;
4. High enough overall excess oxygen levels to complete combustion and maximize thermal efficiency;
5. Proper fuel gas supply system designed to minimize effects of contaminants or fluctuations in pressure and flow on the fuel gas delivered.

Combustion efficiency is dependent on the gas residence time, the combustion temperature, and the amount of mixing in the combustion zone. GCP is accomplished primarily through combustion chamber design as it relates to residence time, combustion temperature, air-to-fuel mixing, and excess oxygen levels. The Department considers GCP and clean fuels a technically feasible control technology for large combined cycle gas-fired turbines.

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

(d) Non-Selective Catalytic Reduction (NSCR)
NSCR uses a catalyst reaction to reduce CO to CO_2. The catalyst is usually a noble metal. The operating temperature for NSCR system ranges from about 700°F to 1,500°F, depending on the catalyst. NSCR requires a low excess oxygen concentration in the exhaust gas stream (typically less than 1%) to be effective because the oxygen must be depleted before the reduction chemistry can proceed. As such, NSCR is only effective with rich-burn gas-fired units that operate at all times with an air-to-fuel (A/F) ratio

controller at or close to stoichiometric conditions. The Department's research did not identify NSCR as a control technology used to control CO emissions from turbines installed at any facility in the RBLC database. Therefore, the Department considers NSCR a technically infeasible control technology for the large combined cycle gas-fired turbines.

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

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

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

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

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

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

Department Evaluation of BACT for CO Emissions from Compressor Turbines
AGDC initially proposed to install oxidation catalyst with an emission rate of 10 ppmvd @ 15% O_2, which would be one of the highest values in the RBLC for CO emissions from large combined cycle turbines. The Department finds that a newly constructed combined cycle turbine with oxidation catalyst controls would be able to achieve a lower emission rate than what was proposed by AGDC. The Department instead selected 2 ppmvd @ 15% O_2 for the CO emission limit after examining emission limits in the RBLC for all large combined cycle turbines using oxidation catalysts. This RBLC search returned results ranging from 0.9 ppmvd at 15% O_2 to 15 ppmvd at 15% O_2,with the majority of the determinations being 2 ppmvd at 15% O_2. All the determinations on the lower end of the RBLC search results were located in the Lower 48 States. The Department intends to set a BACT limit that is achievable by the Permittee and taking into account the harsher and colder environment in Alaska did not feel that a CO limit lower than 2 ppmvd at 15% O_2 would be achievable for the Liquefaction Plant's combined cycle turbines.

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

(a) CO emissions from EUs 7 – 10 shall be controlled by operating and maintaining an oxidation catalyst at all times the units are in operation (except for the 40 hours per year allowed for each EU under the permit);

(b) CO emissions from EUs 7 – 10 shall be controlled by following good combustion practices at all times the units are in operation;

(c) CO emissions from EUs 7 – 10 shall not exceed 2 ppmvd @ 15% O_2 averaged over a 3-hour period; and

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

4.3 Particulates
Possible particulate emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.210: large combined cycle and cogeneration natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 4-3.

Table 4-3: Particulate Control for Large Combined Cycle Natural Gas-Fired Combustion Turbines

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

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

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

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

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

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

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

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

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

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

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

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

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

(d) Particulate emissions from EUs 7 – 10 shall not exceed 10 percent opacity averaged over any six consecutive minutes; and

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

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

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

Control Technology	Number of Determinations	Emission Limits[12](Sulfur in Fuel)
Good Combustion & Clean Fuel	10	0.75 – 5 gr/100 dscf 12.7 – 84.6 ppmv

No Control	1	2 gr/100 dscf 33.8 ppmv

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

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

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

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

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

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

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

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

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

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

4.5 VOC

Possible VOC emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.210: large combined cycle and cogeneration natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 4-5.

Table 4-5: VOC Control for Large Combined Cycle Natural Gas-Fired Combustion Turbines

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

Step 1 – Identify VOC Control Technologies for Power Generation Turbines

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

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

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

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

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

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

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

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

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

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

Applicant Proposal
AGDC proposed to install an oxidation catalyst and use good combustion practices for the power generation turbines EUs 7 – 10 as BACT for reducing VOC emissions. VOC emissions from EUs 7 – 10 will not exceed 2 ppmvd at 15% O_2.

Department Evaluation of BACT for VOC Emissions from Compressor Turbines
AGDC proposed to install oxidation catalyst with an emission rate of 2 ppmvd @ 15% O_2. The RBLC results for combined cycle turbines equipped with oxidation catalysts contains VOC emissions limits ranging from 0.7 to 5 ppmvd at 15% O_2 with a median and mode of 2 ppmvd at 15% O_2. All the determinations in the RBLC search results for the combined cycle turbines below 2 ppmvd at 15% O_2 were located in the Lower 48 States. The Department intends to set a BACT limit that is achievable by the Permittee and taking into account the harsher and colder environment in Alaska, we did not feel that a VOC limit lower than 2 ppmvd at 15% O_2 would be achievable for the Liquefaction Plant's turbines.

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

(a) VOC emissions from EUs 7 – 10 shall be controlled by operating and maintaining an oxidation catalyst at all times the units are in operation (except for the 40 hours per year allowed for each EU under the permit);
(b) VOC emissions from EUs 7 – 10 shall be controlled by following good combustion practices at all times the units are in operation;
(c) VOC emissions from EUs 7 – 10 shall not exceed 2 ppmvd at 15% O_2 averaged over a 3-hour period; and
(d) Initial compliance with the proposed VOC emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

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4.6 GHG

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

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

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

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

Step 1 – Identify GHG Control Technologies for Power Generation Turbines

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

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

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

2. Turbine with Waste Heat Recovery (Combined Cycle or Combined Heat and Power)
In a combined cycle turbine, waste heat recovery units are added to the exhausts of the turbines, and recover previously unused energy to drive a steam turbine generator

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

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

4. Organic Rankine Cycle (ORC)
   ORC uses a refrigerant working fluid that is heated by engine exhaust gas from the natural gas fired turbines, and expands through a turbine connected to the engine shaft. The ORC system involves the same components as in a conventional steam power plant; however, instead of using water as a working fluid, ORC uses a refrigerant with a boiling point lower than that of water, and enables recovery of heat from lower-temperature heat sources. The ORC offers reduced equipment size compared to the steam cycle. This equipment is at their best in air-cooled applications where the heat source is below approximately 400°F. The heat source for this application is the gas turbine exhaust, and is approximately 800 to 1,000 °F, 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 40°F (approximately 50% of the year) makes the system less efficient. Also, additional heat exchangers may be needed to preheat the ORC working fluid and the combustion air, which would increase the cost and complexity of the system. The Department does not consider ORC as a technically feasible technology for control of GHGs.

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

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

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

The Department's research did not identify CCS as a control technology used to control GHG emissions from turbines installed at any facility in the RBLC database. Additionally, the Department contacted the Alaska Department of Natural Resources (DNR) who stated that, as of July 1, 2022, "At this time, the state does not have the regulatory framework to permit the leasing of its lands for CCS projects." Thus there is no viable CCS facility within reasonable proximity for internment of CO_2 sequestration. Therefore, the Department finds that for the Liquefaction Plant, the installation of CCS to compress, transport, and inject CO_2 is not technologically feasible.

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

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

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

As explained in Step 1, CCS and ORC are not considered technologically feasible to control GHG emissions from combined cycle gas-fired turbines larger than 25 MW.

Aeroderivative turbine: the facility is currently designed to use four combined cycle turbines to generate power for the facility. Requiring the power generation turbines to be aeroderivative

models would fundamentally redefine the project, and is therefore not considered as an option in the BACT analysis.

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

(a) GCP and Clean Fuels (<40% Control)

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

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

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

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

(a) GHG emissions from EUs 7 – 10 shall be minimized by maintaining good combustion practices and burning clean fuels (natural gas) at all times the units are in operation; and
(b) GHG emissions from EUs 7 – 10 shall not exceed 117.1 lb/MMBtu averaged over a 3-hour period.

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

5.1 NOx
Possible NOx emission control technologies for limited use diesel engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17:110 to 17.190: Large Internal Combustion Engines (>500 hp) and 17:210: Small Fuel

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Oil-Fired Internal Combustion Engines (<500 hp). The search results for the engines greater than 500 hp and smaller than 500 hp are contained in Tables 5-1 and 5-2 respectively.

Table 5-1: NOx Controls for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Selective Catalytic Reduction	3	0.5 - 0.7
Other Add-On Control	1	1.0
Federal Emission Standards	13	3.0 - 6.9
Good Combustion Practices	31	3.0 - 13.5
No Control Specified	60	2.8 - 14.1

Table 5-2: NOx Controls for Small Diesel-Fired Engines

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

RBLC Review

A review of similar units in the RBLC indicates good combustion practices and Federal emissions standards are the principle NOx control technologies installed on diesel-fired engines. The lowest emission rate listed in the RBLC is 0.5 g/hp-hr for large diesel engines and 2.0 g/hp-hr for small diesel engines.

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

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

(a) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT Section 3.1 for the large combined cycle natural gas-fired combustion turbines and will not be repeated here. The Department considers SCR a technically feasible control technology for both the large and small diesel-fired engines.

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

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

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

(e) Federal Emission Standards
RBLC NOx determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 Subpart IIII, 40 C.F.R 63 Subpart ZZZZ, or EPA tier certifications. Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. The Department considers meeting the technology based New Source Performance Standards (NSPS) of Subpart IIII as a technically feasible control technology for both the large and small diesel-fired engines.

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

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

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

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

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

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

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

Applicant Proposal
AGDC provided an economic analysis of the topmost effective control technology SCR combined with limited operation of 500 hours per year assumed for the largest engine (EU 11), to demonstrate that the use of the most effective control (SCR) is not economically feasible for these limited use diesel engines. A summary of the analyses for the diesel firewater pump EU 11 can be found in Table 5-3.

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.06	0.84	$101,211	$67,554	$80,320
Capital Recovery Factor = 0.0944 (7% interest rate for a 20-year equipment life)					

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

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

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

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

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

Department Evaluation of BACT for NOx Emissions from Diesel-Fired Engines
The Department revised the cost analysis to reflect the equipment life revised to a 25-year lifespan, to account for differences in PTE, and adjusted the interest rate to the current bank prime interest rate of 4.75%. A summary of the analysis for the diesel firewater pump EU 11 can be found in Table 5-4.

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.08	1.1	$101,211	$64,950	$61,859
Capital Recovery Factor = 0.0692 (4.75% interest rate for a 25-year equipment life)					

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

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

(a) NOx emissions from the operation of the diesel engine EUs 11 and 12 shall be controlled by maintaining good combustion practices at all times the units are in operation and installing engines certified to meet NSPS Subpart IIII;

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

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

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

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

5.2 CO

Possible CO emission control technologies for limited use diesel engines were obtained from the

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

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

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

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

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

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

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

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

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

(c) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. As stated above in Section 5.0, all of the diesel-fired engines at the Liquefaction Plant are

considered limited use engines. The Department considers limited operation a technically feasible control technology for both the large and small diesel-fired engines.

(d) Federal Emission Standards
RBLC CO determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 Subpart IIII, 40 C.F.R 63 Subpart ZZZZ, or EPA tier certifications. Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. The Department considers meeting the technology based New Source Performance Standards of Subpart IIII as a technically feasible control technology for both the large and small diesel-fired engines.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Department Evaluation of BACT for CO Emissions from Diesel-Fired Engines

The Department revised the cost analyses to include the CO and VOC emissions removed into one cost calculation, to reflect the equipment life revised to a 25 year lifespan, to account for differences in PTE and greater reduction efficiency achievable with catalytic oxidation, and adjusted the interest rate to the current bank prime interest rate of 4.75%. A summary of the analyses for the diesel firewater pump engine EU 11 can be found in Table 5-9 and the auxiliary air compressor diesel engine EU 12 in Table 5-10.

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.22	0.87	$25,507	$6,214	$7,133
Capital Recovery Factor = 0.0692 (4.75% interest rate for a 25-year equipment life)					

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.11	0.46	$25,507	$6,214	$13,533
Capital Recovery Factor = 0.0692 (4.75% interest rate for a 25-year equipment life)					

The Department's economic analysis indicates the level of CO and VOC reduction does not justify the use of an oxidation catalyst as BACT for the auxiliary air compressor diesel engine EU 12. However, the Department finds that the removal cost of $7,113 per ton for the installation of an oxidation catalyst on the diesel firewater pump engine EU 11 is reasonable, and the RBLC does contain an example of a large diesel engine with oxidation catalyst used to control CO emissions.

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

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

(a) CO emissions from the operation of the diesel-fired engine EU 11 shall be controlled by operating and maintaining an oxidation catalyst at all times the unit is in operation and installing an engine certified to meet NSPS Subpart IIII;

(b) CO emissions from the operation of the diesel-fired engine EU 12 shall be controlled by maintaining good combustion practices at all times the unit is in operation and installing an engine certified to meet NSPS Subpart IIII;

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

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

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

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

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5.3 Particulates

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

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

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

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

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

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

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

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

(b) Diesel Oxidation Catalyst (DOC)
DOC can reportedly reduce PM-2.5 emissions by 30% and PM emissions by 50%. A DOC is a form of "bolt on" technology that uses a chemical process to reduce pollutants in the diesel exhaust into decreased concentrations. They replace mufflers on vehicles, and require no modifications. More specifically, this is a honeycomb type structure that has a large area coated with an active catalyst layer. As CO and other gaseous hydrocarbon particles travel along the catalyst, they are oxidized thus reducing pollution.

The Department considers DOC a technically feasible control technology for the diesel-fired engines.

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

The new EPA Nonroad emissions standards included steps to reduce emissions from the crankcase. Prior to the 2007 rulemaking, the EPA required that crankcase emissions be controlled only on naturally aspirated diesel engines. They had made an exception for turbocharged diesel engines (both highway and nonroad) because of concerns in the past about fouling that could occur by routing the diesel particulates (including engine oil) into the turbocharger and aftercooler. Given the available means to control crankcase emissions, the EPA eliminated this exception for nonroad diesel engines, as they did for highway engines in 2007. EPA anticipates that the diesel engine manufacturers will be able to control crankcase emissions through the use of closed crankcase filtration systems or by routing unfiltered blow-by gases directly into the exhaust system upstream of the emission-control equipment.[13] Therefore, the Department considers emissions from the crankcase as inherently controlled in all EPA Tier 4 Final engines.

(d) Low Sulfur Fuel
Low sulfur fuel has been known to reduce particulate matter emissions. The Department considers low sulfur fuel as a feasible control technology for the diesel-fired engines.

(e) Low Ash Diesel
Residual fuels and crude oil are known to contain ash forming components, while refined fuels are low ash. Fuels containing ash can cause excessive wear to equipment and foul engine components. The Department considers low ash diesel a technically feasible control technology for the diesel-fired engines.

(f) Federal Emission Standards
RBLC PM-2.5 determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 NSPS Subpart IIII, 40 C.F.R 63 Subpart ZZZZ, non-road engines (NREs), or EPA tier certifications. NSPS Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed

[13] EPA Final Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, May 2004; https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&cad=rja&uact=8&ved=2ahUKEwi33OLwgI34AhXmATQIHfTXB-MQFnoECAgQAQ&url=https%3A%2F%2Fwww.epa.gov%2Fregulations-emissions-vehicles-and-engines%2Fregulations-emissions-heavy-equipment-compression&usg=AOvVaw3JYCv-Y26tPtFQqdZmDLVp and 40 C.F.R. 1039.115(a).

after July 11, 2005. The Department considers NSPS Subpart IIII a technically feasible control technology for the diesel-fired engines.

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

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

Step 2 – Eliminate Technically Infeasible Particulate Control Options for Diesel-Fired Engines
All control technologies identified are technically feasible to control particulate emissions from the diesel engines.

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

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

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

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

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

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

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

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

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

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

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

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

Department Evaluation of BACT for Particulate Emissions from Diesel-Fired Engines
The Department revised the cost analysis to reflect the equipment life revised to a 25-year lifespan, to account for differences in PTE, and adjusted the interest rate to the current bank prime interest rate of 4.75%. A summary of the analyses for the diesel firewater pump EU 11 can be found in Table 5-14.

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

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
DPF	0.019	0.17	$43,770	$7,099	$41,955
Capital Recovery Factor = 0.0692 (4.75% interest rate for a 25-year equipment life)					

The Department's economic analysis indicates the level of particulate emissions reduction does not justify the use of a DPF as BACT for any of the limited use diesel engines at the Liquefaction Plant. The Department has already selected an oxidation catalyst control system to control CO and VOC emissions from EU 11 which is considered the next highest control for particulate emissions. For EU 12 the Department found that an oxidation catalyst was not cost effective in Table 5-10, the generators will already combust ULSD (the next highest particulate control) for SO_2 BACT, and emissions from the crankcase are considered inherently controlled by EPA Tier 4 engines which is required for this EU under NSPS Subpart IIII.

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

(a) Particulate emissions from the operation of the diesel engines EUs 11 and 12 shall be controlled by maintaining good combustion practices and installing engines certified to meet NSPS Subpart IIII ;

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

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

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

(e) Particulate emissions from EUs 11 and 12 shall not exceed 10 percent opacity averaged over any six consecutive minutes; and

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

5.4 SO_2
Possible SO_2 emission control technologies for limited use diesel-fired engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110 to 17:190: Large Internal Combustion Engines (>500 hp) and 17.210: Small Fuel Oil-Fired Internal Combustion Engines (<500 hp). The search results for the diesel engines greater than 500 hp and smaller than 500 hp are contained in Tables 5-15 and 5-16 respectively.

Table 5-15: SO_2 Controls for Large Diesel Engines

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

Table 5-16: SO_2 Controls for Small Diesel Engines

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

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

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

(b) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation a technically feasible control technology for the diesel-fired engines.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the CO BACT Section 3.2 for simple cycle turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the diesel-fired engines.

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

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

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

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

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

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

(a) SO_2 emissions from the operation of the diesel-fired engines EUs 11 and 12 shall be controlled by only combusting ULSD at all times the units are in operation;

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

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

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

5.5 VOC

Possible VOC emission control technologies for limited use diesel-fired engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110 to 17:190: Large Internal Combustion Engines (>500 hp) and 17.210: Small Fuel Oil-Fired Internal Combustion Engines (<500 hp). The search results for the diesel engines greater than 500 hp and smaller than 500 hp are contained in Tables 5-17 and 5-18 respectively.

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

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

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

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

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

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

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

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

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and clean fuel to be a technically feasible control technology for both the large and small sized diesel engines.

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

(d) Federal Emission Standards
RBLC VOC determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 Subpart IIII, 40 C.F.R 63 Subpart ZZZZ, or EPA tier certifications. Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. The Department considers meeting the technology based New Source Performance Standards (NSPS) of Subpart IIII as a technically feasible control technology for both the large and small diesel-fired engines.

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

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

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

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

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

Applicant Proposal
AGDC provided economic analyses of the most effective control technology oxidation catalyst with limited operation of 500 hours per year assumed for each engine to demonstrate that the use of an oxidation catalyst is not economically feasible for these limited use diesel engines to control CO emissions. A summary of the analyses for the diesel firewater pump engine EU 11 can be found in Table 5-19 and the auxiliary air compressor diesel engine EU 12 in Table 5-20.

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Table 5-19: AGDC Economic Analysis for Technically Feasible CO Controls (EU 11)

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

Table 5-20: AGDC Economic Analysis for Technically Feasible CO Controls (EU 12)

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

AGDC contends that the economic analysis indicates the level of CO reduction from an oxidation catalyst does not justify the use of an oxidation catalyst for the engine EUs 11 and 12 based on the excessive cost per ton of CO removed per year. Therefore, it will not be cost effective for lowering the smaller amount of VOC emissions from the engines.

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

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

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

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

Department Evaluation of BACT for VOC Emissions from Diesel-Fired Engines

The Department revised the cost analyses to include the CO and VOC emissions removed into one cost calculation, to reflect the equipment life revised to a 25-year lifespan, to account for differences in PTE and greater reduction efficiency achievable with catalytic oxidation and adjusted the interest rate to the current bank prime interest rate of 4.75%. A summary of the analyses for the diesel firewater pump engine EU 11 can be found in Table 5-21 and the auxiliary air compressor diesel engine EU 12 in Table 5-22.

Table 5-21: Department Economic Analysis for Technically Feasible VOC Controls (EU 11)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.22	0.87	$25,507	$6,214	$7,133
Capital Recovery Factor = 0.0692 (4.75% interest rate for a 25-year equipment life)					

Table 5-22: Department Economic Analysis for Technically Feasible VOC Controls (EU 12)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.11	0.46	$25,507	$6,214	$13,533
Capital Recovery Factor = 0.0692 (4.75% interest rate for a 25-year equipment life)					

The Department's economic analysis indicates the level of CO and VOC reduction does not justify the use of an oxidation catalyst as BACT for the auxiliary air compressor diesel engine EU 12. However, the Department finds that the removal cost of $7,113 per ton for the installation of an oxidation catalyst on the diesel firewater pump engine EU 11 is reasonable, and the RBLC does contain an example of a large diesel engine with oxidation catalyst used to control VOC emissions.

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

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

(a) VOC emissions from the operation of the diesel-fired engine EU 11 shall be controlled by operating and maintaining an oxidation catalyst at all times the unit is in operation and installing an engine certified to meet NSPS Subpart IIII;

(b) VOC emissions from the operation of the diesel-fired engine EU 12 shall be controlled by maintaining good combustion practices at all times the unit is in operation and installing an engine certified to meet NSPS Subpart IIII;

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

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

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

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

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5.6 GHG

Possible GHG emission control technologies for limited use diesel-fired engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110 to 17:190: Large Internal Combustion Engines (>500 hp) and 17.210: Small Fuel Oil-Fired Internal Combustion Engines (<500 hp). The search results for the diesel engines greater than 500 hp and smaller than 500 hp are contained in Tables 5-23 and 5-24 respectively.

Table 5-23: GHG Control for Large Diesel-Fired Engines

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

Table 5-24: GHG Control for Small Diesel-Fired Engines

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

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

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

(a) Carbon Capture and Storage
CCS was discussed in detail in the GHG BACT Section 3.6 for simple cycle turbines, and will not be repeated here. The Department's research did not identify CCS as a control technology used to control GHG emissions from diesel-fired engines or any other emission unit type installed at any facility in the RBLC database. Additionally, the Department contacted the Alaska Department of Natural Resources (DNR) who stated that, as of July 1, 2022, "At this time, the state does not have the regulatory framework to permit the leasing of its lands for CCS projects." Thus there is no viable CCS facility within reasonable proximity for internment of CO_2 sequestration. Therefore, the Department finds that for the Liquefaction Plant, the installation of CCS to compress, transport, and inject CO_2 is not technologically feasible.

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

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

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

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

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

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

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

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

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

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

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

6.1 NOx
Possible NOx emission control technologies for the thermal oxidizer were obtained from the RBLC. The RBLC was searched for all processes containing the word thermal oxidizer. The

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search results were then filtered to include only emissions units with thermal oxidizers. The search results for the thermal oxidizer are summarized in Table 6-1.

Table 6-1: NOx Controls for Thermal Oxidizers

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

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

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

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

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

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

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All control technologies identified are technically feasible for thermal oxidizers.

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

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

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

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

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

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

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

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

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6.2 CO

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

Table 6-2. CO Controls for Thermal Oxidizers

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

Step 1 – Identify CO Control Technologies for the Thermal Oxidizer

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

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

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

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

All control technologies identified are technically feasible for thermal oxidizers.

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

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

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

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

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

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

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

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

(b) CO emissions from EU 13 shall not exceed 0.082 lb/MMBtu averaged over a 3-hour period (AP-42, Table 1.4-1, CO emission rate for natural gas combustion in external combustion sources, referenced in Texas Commission on Environmental Quality (TCEQ) NSR Emission Calculations for Vapor Oxidizers guidance document[14]).

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

Table 6-3. Particulate Controls for Thermal Oxidizers

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

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

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

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

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

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

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

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

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

(a) Particulate emissions from EU 13 shall be minimized by good combustion practices and proper equipment design; and
(b) Particulate emissions from EU 13 shall not exceed 0.0075 lb/MMBtu averaged over a 3-hour period (AP-42, Table 1.4-2, PM (Total) emission rate for natural gas combustion in external combustion sources, referenced in TCEQ NSR Emission Calculations for Vapor Oxidizers guidance document[14]).

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

Table 6-4: SO_2 Controls for Thermal Oxidizer

Control Technology	Number of Determinations	Emission Limits

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

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

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

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

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

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

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

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

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

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

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6.5 VOC

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

Table 6-5: VOC Controls for Thermal Oxidizer

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

Step 1 – Identify VOC Control Technologies for the Thermal Oxidizer

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

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

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

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

All control technologies identified are technically feasible for thermal oxidizers.

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

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

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

Step 4 – Evaluate the Most Effective Controls

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

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

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

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

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

(b) VOC emissions from EU 13 shall not exceed 0.0054 lb/MMBtu averaged over a 3-hour period (AP-42, Table 1.4-2, VOC emission rate for natural gas combustion in external combustion sources, referenced in TCEQ NSR Emission Calculations for Vapor Oxidizers guidance document[14]).

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

Table 6-6. GHG Controls for Thermal Oxidizers

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

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

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

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

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

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

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

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

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

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

7.0 VENT GAS DISPOSAL (FLARES)

The Liquefaction Plant will utilize three flare gas systems (i.e., wet, dry, and low-pressure, EUs 14 - 20) to route relief vapors from separate sections of the plant into their respective flare collection headers. The wet flare gas system (EUs 15, 17, and 19) will control waste gas streams containing a significant concentration of water and heavier compounds. The dry flare gas system (EUs 14, 16, and 18) will be used for safe disposal of dry hydrocarbons streams discharged downstream of the dehydration unit. The low-pressure BOG flare gas system (EU 20) will be used for safe disposal of the low-pressure operational release from the LNG storage and loading

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system and intermittent maintenance purging of inert gas from LNG carriers. These flare systems prevent the direct relief to the atmosphere of vent gases that contain VOC and GHG (in the form of CH_4). The flares will emit CO, NOx, SO_2, particulates, VOC, and GHG. The following sections provide the BACT review for each of these pollutants.

7.1 NOx

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

Table 7-1: NOx Controls for Flares

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

Step 1 – Identify NOx Control Technologies for the Flares

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

(a) Thermal Oxidizer and Incinerators

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. Upon passing through the flame, the gas 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 gas mixture will ignite if its temperature is raised to a sufficiently high level. The gas 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 consist 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.

Thermal oxidizers can also be equipped with LNBs to reduce the formation of NOx through careful control of the fuel-air mixture during combustion, as discussed in Section 6.1.

Thermal oxidizers and incinerators are effective in combusting waste gas streams that are more continuous and predictable in nature. However, they are not designed for the efficient combustion of gases under emergency or intermittent conditions where gas flows and composition fluctuate significantly. Furthermore, the VOC destruction efficiency of a thermal oxidizer or incinerator may be compromised under these transient conditions. For example, incinerators are a poor choice for combusting gases under fluctuating conditions, as there is the potential for venting of uncombusted gases during high flow conditions. Likewise, thermal oxidizers are designed to efficiently combust gases within a specific range of flow rates and composition. If that composition varies, particularly during emergency or other intermittent or other events, the destruction efficiency of the burner system can be compromised. Therefore, due to the requirements of the vent gas disposal system, the Department considers thermal oxidizers and incinerators to be technologically infeasible for the Liquefaction Plant.

(b) Flare Gas Recovery

Flare gas recovery is designed to recover flare gases, rather than combust these streams of gas via a thermal oxidizer/incinerator or a flare. Flare gas recovery is the most-effective control technology because the combustion of the gases is reduced/avoided. This not only results in lower VOC and GHG emissions from the uncombusted gases, but also other emissions including NOx, CO, SO_2, particulate matter, and GHGs that would be emitted via the combustion process.

Flare gas recovery is most effective for general service flares. General service flares combust both continuous and intermittent flare gas streams. Continuous streams could be from vapor recovery systems and vent streams specifically directed to the flare on a continuous basis. Flare gas recovery fails as a control technology when it is employed for flares providing control for emergency or intermittent events. Additionally, flare gas recovery is infeasible for gases high in nitrogen, which can contaminate fuel gas sources. For intermittent and emergency events, flare gas recovery provides little to no emissions control. Flare gas recovery is not effective for emergency and intermittent flare gas systems because intermittent and emergency flows breach the water seal system that is necessary to create a closed system and back pressure for the flare gas recovery compressors to operate. During emergency and intermittent flaring, the water seal is breached and gases are safely directed to the flare for combustion.

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Since the Liquefaction Flares are not designed for continuous use as control devices, flare gas recovery provides very limited to no emissions control. Therefore, the Department considers flare gas recovery to be technologically infeasible for the Liquefaction Plant.

(c) 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.

(d) 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.

Step 2 – Eliminate Technically Infeasible NOx Control Options for the Flares
As explained in Step 1, thermal oxidizers/incinerators and flare gas recovery are not feasible to control NOx emissions from the flares.

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

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

Applicant Proposal
AGDC proposed to use good combustion practices, proper flare design, and provided a flare minimization plan for the flares EUs 14 – 20 as BACT for reducing NOx emissions. Additionally, the dry flares EUs 14, 16, and 18 will be limited to 1,000 hours of combined flaring per 12-month rolling period, the wet flares EUs 15, 17, and 19 will be limited to 1,000 hours of combined flaring per 12-month rolling period, and the low pressure flare EU 20 will be limited to 144 hours of flaring per 12-month rolling period. NOx emissions from EUs 14 – 20 will not exceed 0.068 lb/MMBtu.

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

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

(b) Limit the number of hours EUs 14, 16, and 18 flare during startup, shutdown, and maintenance events, to no more than 1,000 hours combined per 12 consecutive month period;[15]

(c) Limit the number of hours EUs 15, 17, and 19 flare during startup, shutdown, and maintenance events, to no more than 1,000 hours combined per 12 consecutive month period;[15]

(d) Limit the number of hours EU 20 flares during startup, shutdown, and maintenance events, to no more than 144 hours per 12 consecutive month period; [16] and

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

7.2 CO

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

Table 7-2. CO Controls for Flares

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

Step 1 – Identify CO Control Technologies for the Flares

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

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

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

(c) Thermal Oxidizer/Incinerators

[15] The 1,000-hour combined flaring limits do not include pilot and purge, emergency, or process upset flaring.
[16] The 144-hour flaring limit does not include pilot and purge, emergency, or process upset flaring.

Thermal oxidizers and incinerators were discussed in Section 7.1. As previously stated, the Department considers this technology technologically infeasible for the Liquefaction Plant.

(d) Flare Gas Recovery
Flare gas recovery was discussed in Section 7.1. As previously stated, the Department considers this technology technologically infeasible for the Liquefaction Plant.

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

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

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

Applicant Proposal
AGDC proposed to use good combustion practices, proper flare design, and provided a flare minimization plan for the flares EUs 14 – 20 as BACT for reducing CO emissions. Additionally, the dry flares EUs 14, 16, and 18 will be limited to 1,000 hours of combined flaring per 12-month rolling period, the wet flares EUs 15, 17, and 19 will be limited to 1,000 hours of combined flaring per 12-month rolling period, and the low pressure flare EU 20 will be limited to 144 hours of flaring per 12-month rolling period. CO emissions from EUs 14 – 20 will not exceed 0.31 lb/MMBtu.

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

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

(b) Limit the number of hours EUs 14, 16, and 18 flare during startup, shutdown, and maintenance events, to no more than 1,000 hours combined per 12 consecutive month period;[15]

(c) Limit the number of hours EUs 15, 17, and 19 flare during startup, shutdown, and maintenance events, to no more than 1,000 hours combined per 12 consecutive month period;[15]

(d) Limit the number of hours EU 20 flares during startup, shutdown, and maintenance events, to no more than 144 hours per 12 consecutive month period;[16] and

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

7.3 Particulates

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

Table 7-3: Particulate Controls for Flares

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

Step 1 – Identify Particulate Control Technologies for the Flares

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

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

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

(c) Thermal Oxidizer/Incinerators
Thermal oxidizers and incinerators were discussed in Section 7.1. As previously stated, the Department considers this technology technologically infeasible for the Liquefaction Plant.

(d) Flare Gas Recovery
Flare gas recovery was discussed in Section 7.1. As previously stated, the Department considers this technology technologically infeasible for the Liquefaction Plant.

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

As explained in Step 1, thermal oxidizers/incinerators and flare gas recovery are not feasible to control particulate emissions from the flares.

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

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

Applicant Proposal
AGDC proposed to use good combustion practices, proper flare design, and provided a flare minimization plan for the flares EUs 14 – 20 as BACT for reducing particulate emissions. Additionally, the dry flares EUs 14, 16, and 18 will be limited to 1,000 hours of combined flaring per 12-month rolling period, the wet flares EUs 15, 17, and 19 will be limited to 1,000 hours of combined flaring per 12-month rolling period, and the low pressure flare EU 20 will be limited to 144 hours of flaring per 12-month rolling period. Particulate emissions from EUs 14 – 20 will not exceed 40 µg/L (equivalent to 0.028 lb/MMBtu).

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

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

(b) Limit the number of hours EUs 14, 16, and 18 flare during startup, shutdown, and maintenance events, to no more than 1,000 hours combined per 12 consecutive month period;[15]

(c) Limit the number of hours EUs 15, 17, and 19 flare during startup, shutdown, and maintenance events, to no more than 1,000 hours combined per 12 consecutive month period;[15]

(d) Limit the number of hours EU 20 flares during startup, shutdown, and maintenance events, to no more than 144 hours per 12 consecutive month period;[16] and

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

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

Table 7-4: SO_2 Controls for Flares

Control Technology	Number of Determinations	Emission Limits
Flare Work Practice Requirements	3	0.0001 – 0.0008 lb/hr

Flaring Minimization Plan	1	13,023.6 lb/hr
GCP & Clean Fuel	3	34 – 1,000 ppmv H_2S in fuel
No Control Specified	4	0.01 – 1,303.99 lb/hr

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

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

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

(c) Thermal Oxidizer/Incinerators
Thermal oxidizers and incinerators were discussed in Section 7.1. As previously stated, the Department considers this technology technologically infeasible for the Liquefaction Plant.

(d) Flare Gas Recovery
Flare gas recovery was discussed in Section 7.1. As previously stated, the Department considers this technology technologically infeasible for the Liquefaction Plant.

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

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

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

Step 4 – Evaluate the Most Effective Controls

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

Applicant Proposal
AGDC proposed to use good combustion practices, proper flare design, and provided a flare minimization plan for the flares EUs 14 – 20 as BACT for reducing SO_2 emissions. Additionally, the dry flares EUs 14, 16, and 18 will be limited to 1,000 hours of combined flaring per 12-month rolling period, the wet flares EUs 15, 17, and 19 will be limited to 1,000 hours of combined flaring per 12-month rolling period, and the low pressure flare EU 20 will be limited to 144 hours of flaring per 12-month rolling period. AGDC will utilize only natural gas in the flares EUs 14 – 20 with a total sulfur content not to exceed 16 ppmv.

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

(a) SO_2 emissions from EUs 14 – 20 shall be minimized by burning natural gas with a total sulfur content not to exceed 16 ppmv, following proper flare work practice requirements and establishing a flaring minimization plan;

(b) Limit the number of hours EUs 14, 16, and 18 flare during startup, shutdown, and maintenance events, to no more than 1,000 hours combined per 12 consecutive month period;[15]

(c) Limit the number of hours EUs 15, 17, and 19 flare during startup, shutdown, and maintenance events, to no more than 1,000 hours combined per 12 consecutive month period;[15]

(d) Limit the number of hours EU 20 flares during startup, shutdown, and maintenance events, to no more than 144 hours per 12 consecutive month period;[16] and

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

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

Table 7-5: VOC Controls for Flares

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

Step 1 – Identify VOC Control Technologies for the Flares

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

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

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

(c) Thermal Oxidizer/Incinerators
Thermal oxidizers and incinerators were discussed in Section 7.1. As previously stated, the Department considers this technology technologically infeasible for the Liquefaction Plant.

(d) Flare Gas Recovery
Flare gas recovery was discussed in Section 7.1. As previously stated, the Department considers this technology technologically infeasible for the Liquefaction Plant.

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

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

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

Applicant Proposal
AGDC proposed to use good combustion practices, proper flare design, and provided a flare minimization plan for the flares EUs 14 – 20 as BACT for reducing VOC emissions. Additionally, the dry flares EUs 14, 16, and 18 will be limited to 1,000 hours of combined flaring per 12-month rolling period, the wet flares EUs 15, 17, and 19 will be limited to 1,000

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hours of combined flaring per 12-month rolling period, and the low pressure flare EU 20 will be limited to 144 hours of flaring per 12-month rolling period. VOC emissions from EUs 14 – 20 will not exceed 0.57 lb/MMBtu.

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

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

(b) Limit the number of hours EUs 14, 16, and 18 flare during startup, shutdown, and maintenance events, to no more than 1,000 hours combined per 12 consecutive month period;[15]

(c) Limit the number of hours EUs 15, 17, and 19 flare during startup, shutdown, and maintenance events, to no more than 1,000 hours combined per 12 consecutive month period;[15]

(d) Limit the number of hours EU 20 flares during startup, shutdown, and maintenance events, to no more than 144 hours per 12 consecutive month period;[16] and

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

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

Table 7-6: GHG Controls for Flares

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

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

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

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

(c) Thermal Oxidizer/Incinerators
Thermal oxidizers and incinerators were discussed in Section 7.1. As previously stated, the Department considers this technology technologically infeasible for the Liquefaction Plant.

(d) Flare Gas Recovery
Flare gas recovery was discussed in Section 7.1. As previously stated, the Department considers this technology technologically infeasible for the Liquefaction Plant.

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

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

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

Applicant Proposal
AGDC proposed to use good combustion practices, proper flare design, and provided a flare minimization plan for the flares EUs 14 – 20 as BACT for reducing GHG emissions. Additionally, the dry flares EUs 14, 16, and 18 will be limited to 1,000 hours of combined flaring per 12-month rolling period, the wet flares EUs 15, 17, and 19 will be limited to 1,000 hours of combined flaring per 12-month rolling period, and the low pressure flare EU 20 will be limited to 144 hours of flaring per 12-month rolling period. GHG emissions from EUs 14 – 20 will not exceed 117.1 lb/MMBtu, which is the CO_2e emissions rates for burning natural gas in 40 CFR Part 98: Mandatory Greenhouse Gas Reporting. The total CO_2e emissions rate is calculated with the equation $CO_2(1) + CH_4(25) + N_2O(298)$.

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

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

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(b) Limit the number of hours EUs 14, 16, and 18 flare during startup, shutdown, and maintenance events, to no more than 1,000 hours combined per 12 consecutive month period;[15]

(c) Limit the number of hours EUs 15, 17, and 19 flare during startup, shutdown, and maintenance events, to no more than 1,000 hours combined per 12 consecutive month period;[15]

(d) Limit the number of hours EU 20 flares during startup, shutdown, and maintenance events, to no more than 144 hours per 12 consecutive month period;[16] and

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

8.0 FUEL TANKS

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

8.1 VOC

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

Table 8-1. VOC Control for Fuel Tanks

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

Step 1 – Identify VOC Control Technologies for Fuel Tanks

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

(a) Floating Roof
Floating roof tanks contain a roof that floats on the surface of the liquid that will rise and fall with the liquid level in the level in the tank, creating no vapor space except for when tanks have low liquid levels. External floating roof tanks are designed with a roof consisting of a double deck or pontoon single deck which rests or floats on the liquid

being contained. An internal floating roof includes a fixed roof over the floating roof, to protect the floating roof from damage and deterioration. In general, the floating roof covers the entire liquid surface except for a small perimeter rim space. Under normal floating conditions, the roof floats essentially flat and is centered within the tank shell. The floating roof must be designed with perimeter seals (primary and secondary seals) which slide against the tank wall as the roof moves up and down. The use of perimeter seals minimizes emissions of VOCs from the tank. Sources of emissions from floating roof tanks include standing storage loss and withdrawal losses. Standing losses occur due to improper fits between tank seal and the tank shell. Withdrawal losses occur when liquid is removed from the tank, lowering the floating roof, revealing a liquid on the tank walls which vaporize. The Department considers floating roof tanks as a technically feasible control option for fuel tanks.

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

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

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

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

Step 2 – Eliminate Technically Infeasible VOC Control Options for Fuel Tanks
The largest of the diesel fuel tanks at the Liquefaction Plant is 3,520 gallons and is expected to be horizontal, square or rectangular in shape. This design is not conducive to a floating roof,

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which are found in larger round fuel tanks (greater than 20,000 gallons). While the condensate storage tanks are large in design, the vapor pressure of condensate can be quite high (i.e. exceed 11 psia) under certain temperature conditions. This highly volatile liquid would compromise the integrity of the seal systems on internal and external floating roof tanks. Therefore, a floating roof control system is eliminated from further consideration for both the diesel and condensate tanks.

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

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

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

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

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

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

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

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

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

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

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

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Appendix C: BACT Summary

Table C-1. NOx BACT Limits

EU ID	Description	BACT Limit	BACT Control
1 – 6	1,113 MMBtu/hr Simple Cycle Treated Gas Compressor Turbines	2 ppmvd at 15% O_2	Selective Catalytic Reduction; DLN Combustors; Good Combustion Practices
7 – 10	384 MMBtu/hr Combined Cycle Power Generation Combustion Turbines	2 ppmvd at 15% O_2	Selective Catalytic Reduction; DLN Combustors; Good Combustion Practices
11	575 hp Firewater Pump Engine (ULSD)	3.6 g/hp-hr	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
12	300 hp Auxiliary Air Compressor Engine (ULSD)	0.45 g/hp-hr	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
13	Vent Gas Disposal (Thermal Oxidizer) 6.0 MMBtu/hr	0.055 lb/MMBtu	Low NOx Burners; Proper Equipment Design; Good Combustion Practices
14 – 20	Vent Gas Disposal (Flares) 2.1 – 55,000 Mscf/hr	0.068 lb/MMBtu	Limited Operation; Flare Work Practices; Flaring Minimization Plan

Table C-2. CO BACT Limits

EU ID	Description	BACT Limit	BACT Control
1 – 6	1,113 MMBtu/hr Simple Cycle Treated Gas Compressor Turbines	5 ppmvd at 15% O_2	Oxidation Catalyst; Good Combustion Practices
7 – 10	384 MMBtu/hr Combined Cycle Power Generation Combustion Turbines	2 ppmvd at 15% O_2	Oxidation Catalyst; Good Combustion Practices
11	575 hp Firewater Pump Engine (ULSD)	3.3 g/hp-hr	Oxidation Catalyst; Limited Operation; 40 CFR 60 Subpart IIII
12	300 hp Auxiliary Air Compressor Engine (ULSD)	3.3 g/hp-hr	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
13	Vent Gas Disposal (Thermal Oxidizer) 6.0 MMBtu/hr	0.082 lb/MMBtu	Proper Equipment Design; Good Combustion Practices
14 – 20	Vent Gas Disposal (Flares) 2.1 – 55,000 Mscf/hr	0.31 lb/MMBtu	Limited Operation; Flare Work Practices; Flaring Minimization Plan

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Table C-3. Particulate BACT Limits

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

Table C-4. SO_2 BACT Limits

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

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C-5. VOC BACT Limits

EU ID	Description	BACT Limit	BACT Control
1 – 6	1,113 MMBtu/hr Simple Cycle Treated Gas Compressor Turbines	2 ppmvd at 15% O_2	Oxidation Catalyst; Good Combustion Practices
7 – 10	384 MMBtu/hr Combined Cycle Power Generation Combustion Turbines	2 ppmvd at 15% O_2	Oxidation Catalyst; Good Combustion Practices
11	575 hp Firewater Pump Engine (ULSD)	0.19 g/hp-hr	Oxidation Catalyst; Limited Operation; 40 CFR 60 Subpart IIII
12	300 hp Auxiliary Air Compressor Engine (ULSD)	0.22 g/hp-hr	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
13	Vent Gas Disposal (Thermal Oxidizer) 6.0 MMBtu/hr	0.0054 lb/MMBtu	Proper Equipment Design; Good Combustion Practices
14 – 20	Vent Gas Disposal (Flares) 2.1 – 55,000 Mscf/hr	0.66 lb/MMBtu	Limited Operation; Flare Work Practices; Flaring Minimization Plan
21 – 23	Gas Condensate Storage Tanks and Loading System (126,904 – 457,890 gallons)	N/A	Vapor Recovery and Routing to Thermal Oxidizer
23 – 25	Diesel Storage Tanks (342 – 3,520 gallons)	0.01 tpy	Submerged Fill

Table C-6. GHG BACT Limits

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

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Appendix D: Modeling Report

Alaska Department of Environmental Conservation
Air Permit Program

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

Construction Permit AQ1539CPT01
Revised: 7 July, 2022

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

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

2. PROJECT BACKGROUND

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

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

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2.1. Area Classification

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

2.2. Ambient Demonstration Requirements

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

- 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).

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

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

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

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

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

Tuxedni is located within the 100 km notification range. The Q/d ratio also exceeds 10 at both Tuexedni and Denali. The Department, therefore, notified5 the FWS and the NPS of the pending PSD application on 12 October, 2017.[6] The FWS responded the same day by saying they would like to kept informed and that they wanted to discuss the AQRV evaluation.[7] The NPS expressed their interest during a 24 October, 2017 teleconference with the FLMs.

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

2.3. Increments and Baseline Dates

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

2.4. Additional Comments Regarding Various Procedural Issues

2.4.1. Interface with the National Environmental Policy Act

AGDC conducted various air quality demonstrations under the National Environmental Policy Act (NEPA) prior to submitting their permit application for the Liquefaction Plant.[8] They therefore relied on these previous demonstrations, to the extent possible, for the ambient analyses required under PSD. This type of coordinated approach is

[5] The Department notified FLM stakeholders in accordance with 40 C.F.R. 52.21(p). They expressed interest in AGDC's characterization and estimation of impacts in both the Class I areas subject to review and expanded areas of concern. Salient FLM concerns are summarized in their public comment submission. See Section 7 for a relevant discussion of impacts addressed by AGDC.

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

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

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

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encouraged by EPA under 40 CFR 52.21(s). The Department has not adopted this citation by reference (since it has no control over the federal actions conducted under NEPA), but the Department nevertheless agrees that the analyses should be consistent where possible.

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

2.4.2. Modeling Protocol Submittal

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

2.4.3. Guideline on Air Quality Models

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

EPA has made a number of updates to the *Guideline on Air Quality Models* (Guideline) over time. The Department used the 2005 version of the Guideline for the Liquefaction Plant modeling review since that was the version adopted by reference in 18 AAC 50.040(f) at the time of the protocol review.[9] EPA had previously promulgated an update to the Guideline on 17 January, 2017, but they also provided a one year transition period for the permitting authorities to incorporate the update into their air permit programs. EPA further stated:

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

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

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

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2.4.4. Application Submittal

AGDC provided the Department with an application for their permit on 1 May, 2018. The Department requested additional information[10] on 29 June, 2018, 3 December, 2019, and 28 April, 2020. AGDC provided responses to these requests, including supplemental files, on 24 September, 2018, 10 January, 2020, and 5 May, 2020, respectively.

3. REPORT OUTLINE

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

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

4. PRE-CONSTRUCTION MONITORING DATA

40 CFR 52.21(m)(1) requires PSD applicants to submit ambient air monitoring data describing the air quality in the vicinity of the project, unless the existing concentration or the project impact is less than the applicable Significant Monitoring Concentration provided in 40 CFR 52.21(i)(5). The requirement only pertains to those pollutants that are subject to PSD review and have a National Ambient Air Quality Standard (NAAQS).[11] If monitoring is required, the data are to be collected prior to construction. Hence, these data are referred as "pre-construction monitoring" data. Ambient "background" data may also be needed to supplement the estimated ambient impact from the proposed project. AGDC's approach for meeting the pre-construction data requirement is discussed below. Their approach for meeting the "background" data needs is described in Section 5.14 (**Off-Site Impacts***)* of this report.

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

[11] 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.

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Pre-construction monitoring data must be collected at a location and in a manner that is consistent with the EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA-450/4-87-007), which the Department adopted by reference in 18 AAC 50.035(a)(5). In summary, the data must be collected at the location(s) of existing and proposed maximum impacts, the data must be current, and the data must meet PSD quality assurance requirements. The current quality assurance requirements are described in 18 AAC 50.215(a).

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

For their site-specific data collection effort, AGDC provided a Quality Assurance Project Plan (QAPP) for Department review and approval, in order to assure they had an acceptable approach for obtaining ambient data. They also submitted the subsequent data sets for review and approval. The Department requested additional information associated with the resultant data13 on 19 February, 2020. AGDC provided a response to this request on 4 March, 2020. The resulting periods with PSD quality data are listed by pollutant in Table 1. The AAAQS and maximum concentrations, as measured according to the form of the given AAAQS, are also provided. The Department is reporting the gaseous pollutants on a mass basis in micrograms per cubic meter ($\mu g/m^3$) which is the convention used in modeling, rather than on a volumetric basis in parts-per-million (ppm), which is the convention typically used in monitoring reports.

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

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

Table Notes:

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

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

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

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

Air Pollutant	Avg. Period	Monitoring Period	Max Conc (μg/m³)	AAAQS (μg/m³)	% of AAAQS
PM-10	24-hour	2013-2014	**49.0**	150	32.7
PM-2.5	24-hour		**24.0**	35	68.6
	Annual		**3.7**	12	30.8
O_3	8-hour		**100**	140	71.4

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

5. NEAR-FIELD SOURCE IMPACT ANALYSES

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

5.1. Approach

AGDC used a "normal operations" modeled scenario to provide a conservative estimate of the Liquefaction Plant ambient impacts. This scenario is generally characterized by the full-capacity operation of all three compression turbine trains and the associated power generation units, in addition to non-transient marine terminal emissions and the limited use of various emergency and intermittently used EUs. Additional information regarding this scenario is available in Section 4.1.1 of the Liquefaction Plant Modeling Report.[14] AGDC did not model other operational scenarios, e.g., plant start-up, early plant operations, and maintenance operations, under the assumption that these scenarios would have fewer emissions and, consequently, smaller ambient impacts. Similarly, they did not model the Liquefaction Plant construction phase for the reasons described in Section 5.6.3 of this report. AGDC's modeled approach emphasizing the "normal operations" scenario is reasonable.

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

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AGDC used a two-step approach for modeling the normal operations scenario. They first compared the ambient impact from just the Liquefaction Plant EUs, i.e., the project impacts, to the significant impact levels (SILs) listed in Table 5 of 18 AAC 50.215(d). Impacts less than the SIL are considered negligible. They then conducted a cumulative impact analysis for those pollutants and averaging periods with significant impacts. The cumulative impacts are compared to the AAAQS or increment, as applicable.

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

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

As subsequently discussed in Section 6 of this report, *Modeling Results and Discussion*, project impacts for the Liquefaction Plant exceed the SIL for most of the modeled pollutants and averaging periods. AGDC, therefore, included several off-site sources[15] in their cumulative impact analyses noting the likelihood for significant concentration gradients near the Liquefaction Plant. The following sub-sections provide additional details regarding AGDC's modeling analysis.

5.2. Model Selection

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

The AERMOD Modeling System consists of three major components: AERMAP, used to process terrain data and develop elevations for the receptor grid and EUs; AERMET, used to process the meteorological data; and the AERMOD dispersion model, used to estimate the

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

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ambient pollutant concentrations. EPA has also developed an AERMET support program, AERMINUTE, to calculate hourly average wind speeds and directions from one-minute Automated Surface Observing System (ASOS) data. AGDC used the versions of AERMAP, AERMINUTE, AERMET, and AERMOD that were current at the time that they conducted their NEPA analysis: AERMAP version 11103; AERMINUTE version 14337 (AERMINUTE 14337), AERMET version 15181 (AERMET 15181); and AERMOD version 15181 (AERMOD 15181).

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

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

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

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

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EPA made a number of changes to AERMOD and AERMET; but none of them would lead to an increased impact in the Liquefaction Plant modeling analysis. The Department nevertheless reran AGDC's 24-hour PM-2.5 and one-hour NO_2 sensitivity analyses using AERMET/AERMOD 18081 to further confirm that the AERMET/AERMOD versions used by AGDC remains acceptable. The Department's sensitivity analyses are further discussed below.

5.2.1. AERMOD Sensitivity Analyses

AGDC re-ran their one-hour NO_2 and 24-hour PM-2.5 cumulative impact AAAQS analyses observing the former as yielding worst-case estimated ambient impacts. They used AERMINUTE 15272, AERMET 16216 and AERMOD 16216r for these sensitivity analyses. AGDC relied upon the 2008 through 2012 meteorological dataset used in their underlying NEPA analyses; see Section 5.3 of this report for additional detail.[16]

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

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

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

Table 3. AERMOD Sensitivity Results (μg/m³)

Pollutant and Averaging Period	Modeled Design Concentration When Using AERMOD Version:		
	15181	16216r	18081
one-hour NO_2	149.47826	149.49961	149.57037

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

24-hour PM-2.5	6.38954	6.38955	6.35817

5.3. Meteorological Data

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

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

5.3.1. Tall Stack Considerations

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

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

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

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

5.3.1.1 Tall Tower Data Collection

Alaska LNG proposed a site in Nikiski for a 60-meter tower on 25 February, 2014 and submitted a slightly revised location on 6 June, 2014. The Department

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approved the revised location on 13 June, 2014. The Department approved the subsequently submitted Quality Assurance Project Plan on 20 April, 2015.

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

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

5.3.1.2 Analysis Criteria

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

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

5.3.1.3 Analysis and Review

AGDC provided a comparison of the observed winds, as well as a comparison of the modeled impacts. They compared the annual wind rose from the 30-m Nikiski data to the annual wind rose from the eight-m Kenai data for calendar year 2015. They correctly stated, "*In general, the wind roses are similar with a few notable differences, such as an apparent shift in the prevailing winds from southerly winds at Nikiski toward southwesterly winds at Kenai.*" They provided a reasonable discussion regarding the similarities and differences. They appropriately noted that

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annual frequency plots highlight general patterns, but they "*...are not generally useful for comparing winds over short-term averaging periods or for providing information on where maximum short-term pollutant concentrations will be predicted.*"

AGDC, then Alaska LNG, [17] conducted the AERMOD sensitivity analysis at the project impact level, rather than the cumulative impact level. They stated the nearby offsite sources were not included in the analysis "*...because (1) they were not the focus of the permitting, (2) they are generally comprised of sources with shorter stacks, and (3) [the Department] has approved modeling these sources with meteorological data collected at 10 meters or less.*" The Department agrees with AGDC's reasoning and approach.

AGDC included the full project EU inventory in the analysis, rather than just the EUs with tall stacks. They stated a culpability analysis showed little difference in results between a full inventory and tall stack inventory. Therefore, they used the full inventory for simplicity. The Department agrees with the full project inventory approach.

AGDC used AERMET/AERMOD version 15181 for the analysis. They compared the modeled one-hour NO_2, 24-hour PM-2.5, annual NO_2, and annual PM-2.5 impacts for the following three meteorological datasets:

1) eight-m Kenai data from 2015;
2) 30-m and 60-m Nikiski data from 2015; and
3) 30-m Nikiski data from 2015, i.e., without the 60 m data.

The modeled design concentrations[18] from the three datasets are similar, but not identical, as shown in Table 4. The dataset with the largest value varies by pollutant and averaging period. The Kenai data generally provided the largest concentration, but both the Nikiski datasets provided the largest 24-hour PM-2.5 values.

Table 4. Tall Tower Sensitivity Results (µg/m³)

Pollutant	Avg. Period	Modeled Design Concentration When Using the Following Meteorological Data:		
		Kenai (8-m Tower)	Nikiski (30- and 60-m Measurements)	Nikiski (30-m Measurements)
NO_2	one-hour	141.2	135.4	133.3
	Annual	8.56	7.63	7.41
PM-2.5	24-hour	3.72	4.14	4.06

[17] The Department will use "AGDC" as a simplification of "Alaska LNG/AGDC" from this point forward, rather than attempting to differentiate which party conducted which part of the tall tower sensitivity analysis/write-up.
[18] Design concentrations are discussed in Section 5.15 of this report.

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	Annual	0.42	0.42	0.36

The analytical results[19] of AGDC's sensitivity analyses suggest that meteorological measurements between the heights considered demonstrate little impact on the associated estimated model output. Their results further suggest that impacts at the Liquefaction Plant are driven by the emissions from stacks with release points above 20 m in height, rather than those with releases below this height. Based on a review of these results, the Department finds that AGDC's use of 10-m meteorological data is acceptable for modeling the proposed Liquefaction Plant stationary source, but notes that this conclusion cannot be generally applied to all stationary sources with tall stacks; see the associated discussion in the Modeling Report for AGDC's GTP stationary source for relevant detail.

5.3.2. Processing the NWS Data

As previously noted in Section 5.2 of this report, AGDC used AERMINUTE 14337 and AERMET 15181 to reprocess the 2008 – 2012 NWS data. AERMINUTE requires the user to provide the start-up date for the Ice Free Winds (IFW) setting, which is the date the NWS started using a sonic anemometer at that station. AGDC continued to use the 21 September, 2006 IFW commission date for the Kenai airport station.

AERMET requires the area surrounding the surface meteorological tower to be characterized with regard to the following three surface characteristics: noon-time albedo, Bowen ratio, and surface roughness length. AGDC continued to use the previously approved values, which are repeated below in Table 5.

Table 5. Approved AERMET Surface Parameters for Kenai NWS Data

Surface Parameter	Spring	Summer	Autumn	Winter
Albedo	0.143	0.145	0.152	0.406
Bowen Ratio	0.509	0.395	0.658	0.426
Surface Roughness Length (m)				
Sector 1 (30° - 60°)	0.071	0.112	0.071	0.005
Sector 2 (60° - 90°)	0.138	0.197	0.138	0.022
Sector 3 (90° - 120°)	0.140	0.176	0.140	0.045
Sector 4 (120° - 150°)	0.141	0.177	0.141	0.046
Sector 5 (150° - 180°)	0.073	0.109	0.073	0.008
Sector 6 (180° - 210°)	0.050	0.069	0.050	0.008
Sector 7 (210° - 240°)	0.036	0.060	0.036	0.002
Sector 8 (240° - 270°)	0.078	0.104	0.078	0.019
Sector 9 (270° - 330°)	0.034	0.050	0.034	0.004
Sector 10 (330° - 30°)	0.045	0.065	0.045	0.005

[19] Provided by AGDC to FERC as Attachment C: Attachment 3 of Resource Report 9

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Table Note: For purposes of the Kenai NWS AERMET surface parameters, spring is defined as April through May, summer is defined as June through August, autumn is defined as September through October, and winter is defined as November through March.

AGDC instructed AERMET to randomize the wind direction by ± 5 degrees. Randomization of the wind direction is a long-standing practice when using *hourly* NWS data since the data are recorded to the nearest 10 degrees. However, EPA clarified in a March of 2013 memorandum that the use of hourly-averaged wind directions from AERMINUTE, "*...eliminates the need to randomize the wind directions associated with standard NWS observations.*" [20] The Department ran two sensitivity analyses to see whether the use of randomized winds in AERMET significantly affects AGDC's modeling results. It does not. The Department reran the 24-hour PM-10 increment analysis for the worst-case meteorological data year (2010) using the same version of AERMET and AERMOD as used by AGDC (i.e, AERMET/AERMOD 15181), but without randomization of the wind direction. The high second-high (h2h) design concentration matched AGDC's value, as did the high first-high (h1h) concentration. The Department also reran the annual NO_2 increment analysis from AGDC's AERMET/AERMOD 16216 sensitivity analysis for the maximum impact receptor when using a MAR of 0.2; see Section 5.2.1 of this report.[21] The maximum impact was marginally smaller (12.52613 $\mu g/m^3$ instead of 12.53158 $\mu g/m^3$), which is inconsequential. The Department therefore accepts AGDC's AERMET settings for the Liquefaction analysis. ***However, the Department encourages AGDC to use the non-randomization setting in the future***. The Department used the non-randomization setting in all AERMET/AERMOD 18081 runs that it conducted as part of its review.

AERMET contains an option for adjusting the surface friction velocity (ADJ_u*) parameter. EPA developed this option to correct AERMOD's tendency to overpredict impacts under stable, low wind conditions. AGDC did not use the ADJ_u* option for the Liquefaction Plant modeling analyses.[22] Some of the modeled results may therefore be overstated.

5.4. Coordinate System

Air quality models need to know the relative location of the EUs, structures (if applicable), and receptors, in order to properly estimate ambient pollutant concentrations. Therefore, applicants must use a consistent coordinate system in their analysis.

AGDC used the Universal Transverse Mercator (UTM) grid for their coordinate system. This is the most commonly used approach in AERMOD assessments. The UTM system divides the world into 60 zones, extending north-south, and each zone is 6 degrees wide in

[20] EPA Memorandum from Tyler Fox to Regional Modeling Contacts, *Use of ASOS meteorological data in AERMOD dispersion modeling;* 8 March, 2013.

[21] The Department reran the annual NO_2 increment analysis for the worst-case meteorological data year (2010).

[22] The ADJ_u* option was considered as an alternative modeling technique when AGDC conducted their NEPA modeling analysis. Alternative modeling techniques require case-specific justification and Department/R10 approval under 18 AAC 50.215(c).

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longitude. The modeled EUs, structures, and receptors are all located in UTM Zone 5. AGDC used the North American Datum of 1983 reference for each UTM coordinate.

5.5. Terrain

Terrain features can influence plume dispersion and the resulting ambient concentration. Digitized terrain elevation data is therefore generally included in a modeling analysis. AERMOD's terrain preprocessor, AERMAP, utilizes the terrain data to obtain the base elevations for the modeled EUs, buildings, and receptors; and to calculate a "hill height scale" for each receptor.

AGDC used National Elevation Dataset (NED) files for their terrain dataset. NED is the current terrain elevation dataset provided by the United States Geological Survey. AGDC's use of NED data is therefore reasonable and appropriate.

5.6. EU Inventory

The modeled EU inventory for the Liquefaction Plant is described below, along with the off-site inventory that AGDC used in the cumulative impact analyses. The secondary emissions required in a cumulative impact analysis are also discussed.

5.6.1. Liquefaction Plant EU Inventory

AGDC modeled the Liquefaction Plant compressor and power generation turbines, air compression and firewater pump engines, dry and wet ground flares, low pressure flare, and thermal oxidizer as described in their modeling report[23] provided as Appendix D to Resource Report 9. They additionally modeled emissions from the assumed marine terminal operations during vessel maneuvering, cool-down, hoteling, loading, and purging as described in Section 4.1.1.2 of the appended report. The location of the modeled EUs is provided in Figure 5-5 of the aforementioned report. AGDC characterized all of the EUs as point sources; see the associated discussion in Section 5.7 of this modeling report for additional detail. AGDC conservatively assumed that all the modeled EUs operate concurrently.

5.6.2. Off-site EU Inventory

AGDC included a number of off-site sources in their cumulative impact analyses as broached at the end of Section 5.1 of this report. A summary and characterization of the modeled off-site EUs are listed in Section 10 of Appendix A to AGDC's Modeling Report, itself provided as Appendix D to Resource Report 9.

AGDC used relevant information from a recent permitting effort at the nearby Kenai Nitrogen Operations stationary source to develop their off-site inventory for AAAQS and PSD increment analyses; the former includes information germane to those EUs

[23] Specific detail on these modeled EUs are presented in Tables 4-1 through 4-3 of said report.

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that are increment consuming[24]. They also used 2011 information from the Department's point source inventory and National Emissions Inventory database to support their analyses. The off-site inventory varies by pollutant since the baseline date is pollutant-specific; additional detail is provided in Section 2.3 of this report. AGDC's characterization of the explicitly modeled off-site EUs offers a representative characterization of the associated sources. It is sufficient to estimate the impact from those sources anticipated to cause significant concentration gradients within the project area. The Department finds that the off-site inventory is appropriate for those pollutants and averaging periods considered.

5.6.3. Secondary Emissions Inventory

PSD applicants must include "secondary emissions" in their ambient demonstration, per 40 CFR 52.21(k)(1). EPA defines the term in 40 CFR 52.21(b)(18) as, "*emissions which would occur as a result of the construction or operation of a major stationary source… but do not come from the major stationary source…*" However, secondary emissions do not include "*any emissions which come directly from a mobile source*." Subsequent EPA guidance further clarifies that the definition in 40 CFR 52.21(b)(18) "*sets out four tests to be used in determining whether such emissions are to be included in air quality impact assessments for PSD purposes: the emissions must be specific, well defined, quantifiable, and impact the same general area*." [25]

The only secondary emissions that would occur due to the construction and operation of the Liquefaction Plant are the construction emissions that would occur within the local area. The emissions that would occur due to the remaining aspects of the AK LNG Project, including the construction/operation of the Pipeline Stations and the Gas Treatment Plant, are <u>not</u> secondary emissions for purposes of the Liquefaction Plant PSD review since they will not occur in the same general area as the Liquefaction Plant emissions.[26]

AGDC advanced a general discussion of their construction emissions in Section 4.1.3 of the Liquefaction Plant Modeling Report, provided as Appendix D to Resource Report 9; a more detailed discussion is provided in Appendix C to this report, *Emissions Associated with Project*. AGDC stated the Liquefaction Plant construction phase would last approximately eight years, beginning in the second year to follow the project authorization. They also indicate that construction of the Marine Terminal, while beginning contemporaneously, will span a four-year period. AGDC noted that the Liquefaction Plant construction efforts will be multifaceted and include differing time

[24] AGDC summarized the installation/modification date and increment consuming status of their off-site EUs in Appendix A of the Liquefaction Plant Modeling Report, itself provided as Appendix D to Resource Report 9.

[25] 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*; 17 March, 1981.

[26] The Gas Treatment Plant, and each of the Pipeline Stations, are separate stationary sources for air quality permitting purposes. The ambient impacts associated with each of those stationary sources will be assessed, as warranted, under the permit requirements for that stationary source.

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scales and site locations for the various activities. Their characterization of construction activities and the associated estimated emissions are anticipated to result in secondary emissions that are less than the operational emissions used in the modeling analysis.

Developing the parameters needed to correctly characterize and simulate constantly changing construction emissions, especially fugitive dust emissions, is challenging. In some cases, the resulting concentrations are questionable, if not overly conservative. The Department further notes that the modeling results generally lead to the imposition of fugitive dust control plans to minimize said impacts and/or requirements to install vertical, uncapped exhaust stacks on the construction camp engines to reduce the impacts from these combustion sources; see Sections 5.7.7 and 5.8.2 of this report for additional detail. The Department is, therefore, imposing its typical endpoint of the aforementioned reasoning, i.e. ambient air conditions, rather than requiring AGDC to develop the details needed to explicitly model their construction phase emissions. These construction phase conditions include:

- Fugitive dust control;
- A requirement to construct and maintain vertical, uncapped stacks on all temporary construction camp engines; and
- A requirement to install and operate PM-10 and PM-2.5 ambient air monitoring stations throughout the construction phase.

The ambient air monitoring provision includes an action plan that requires evaluation and possible further control of the dust-generating activities at set concentration levels.

5.7. Liquefaction Plant Emission Rates and Stack Parameters

The Department generally found the modeled emission rates to be consistent with the emissions information provided throughout their application. The modeled stack parameters are likewise generally reasonable. The exceptions, or items that otherwise warrant additional comment, are discussed below.

AGDC used the same EU inventory, emission rates, and stack parameters in the Class II increment analyses as used in the AAAQS demonstrations. This is an appropriate approach since the Liquefaction Plant EUs are increment consuming; see the associated discussion in Section 2.3 of this report.

5.7.1. Turbines

Six simple-cycle compression turbines (**EUs 1 through 6**) and four power generation turbines (**EUs 7 through 10**) will be installed and operated at the Liquefaction Plant. The power generation turbines will be equipped with Waste Heat Recovery Units (WHRUs) that are not designed with supplemental firing. For their WHRU-equipped turbines, AGDC's ambient demonstration appears to observe a regime of diminished exhaust temperature and momentum, relative manufacturer or vendor data for similar

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units, assuming a WHRU-diverted exhaust stream. For all modeled turbines, AGDC used exhaust parameters that reflected the anticipated worst-case loads and ambient temperatures to conservatively estimate both short-term and annualized ambient impacts; they assumed the full-time operation of all turbines. A detailed discussion of ADGC's turbine modeling approach, including the specific release parameters, is detailed in their Modeling Report provided as Appendix D to Resource Report 9.

5.7.2. Thermal Oxidizer

A thermal oxidizer (**EU 13**) will be operated at the Liquefaction Plant for the destruction of VOCs. AGDC modeled this unit assuming a consistent flow of input gas across the year, i.e. 8,760 hr/yr. This characterization is appropriate for both annual and short-term AAAQS/increment demonstrations at the Liquefaction Plant.

5.7.3. Flares

Six ground flares (**EUs 14 through 19**), three dry three wet, will be installed and intermittently operated at the Liquefaction Plant as safety devices during relief, maintenance, and upset conditions. An elevated low-pressure flare (**EU 20**) will also be operated for various facility and Marine Terminal operations under similar episodic conditions. All flares are generally modeled using an assumption of continuous operation under their pilot/purge gas operational regimes, which is discrete from intermittent operation subject to relief, maintenance, and upset conditions. Operation during these conditions is reflected in AGDC's ambient demonstration with of 500 hr/yr of maximum impact flaring, each, for the ground flares and 144 hr/yr for the elevated low-pressure flare. While the latter scenarios are generally characterized as unplanned and/or episodic, intermittent flaring emissions are accounted for in the modeling by superposition of emission rates in both annual and short-term AAAQS/increment analyses; see the Department's Modeling Report for the GTP stationary source for a related discussion regarding AGDC's modeled short-term flaring assumptions. AGDC used the rated capacity of the flares to calculate the emissions and plume characteristics during their assumed flaring events.

Flares can typically be treated as point sources, but they require special handling since the emissions are generated outside of the flare stack. Most applicants use the approach described in Section 2.1.2 of EPA's AERSCREEN User's Guide, whereby the exhaust temperature is set to 1273K, the exit velocity is set to 20 meters per second (m/s), the stack height is the physical height plus flame length, and the stack diameter is based on the heat release rate. AGDC used the AERSCREEN approach for characterizing the pilot/purge conditions as well as the flaring events.

The maximum impact from episodic flaring events generally occurs well beyond the area of a stationary source's total maximum impact in the absence of significant complex terrain. This trend is especially salient in the case of the Liquefaction Plant due to large assumed flare plume heights given an extremely buoyant exhaust during flaring events and, in the case of the elevated low-pressure flare, a tall physical stack height;

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see Section 5.7.6 of this report for additional detail. As such, large effective stack heights of up to up to 172.8 m above base elevation, in the case of the ground flares, are used in AGDC's model inputs. These modeled stack heights, along with the additional plume rise from the high temperature release, lead to relatively large travel distances prior to plume touchdown.

An increased travel distance of flaring emissions from the Liquefaction Plant allows for increased dispersion of the associated ambient impacts. Consequently, the resulting impact from flaring is anticipated to be substantially smaller than the maximum total impact. Therefore, there is no need to incorporate AGDC's short-term flaring assumptions as permit conditions to protect ambient air quality.

5.7.4. Reciprocating Engines

AGDC intends to operate two reciprocating internal combustion engine (RICE) at the Liquefaction Plant, an emergency firewater pump (**EU 11**) and auxiliary air compressor (**EU 12**). For their ambient demonstration, AGDC assumed each RICE EU operates for only 500 hours-per-year (hr/yr). AGDC used this assumption to derive the emission rates used in the annual AAAQS/increment demonstrations and one-hour NO_2 and SO_2 AAAQS demonstrations. The annual emission rate may be used to characterize intermittently operated EUs in the one-hour NO_2 and SO_2 AAAQS demonstrations per EPA policy.[27] The Department is imposing AGDC's 500 hr/yr assumption as an ambient condition to protect the annual AAAQS/increments, as well as the one-hour NO_2 and SO_2 AAAQS.

5.7.5. Sulfur Compound Emissions

SO_2 emissions are directly related to the sulfur content of the fuels fired. AGDC assumed their liquid fuel-fired EUs fire fuel with a sulfur content of 15 parts-per-million by weight (ppmw). They assumed their fuel gas-fired EUs fire fuel with a total sulfur content of 16 parts-per-million by volume (ppmv). The Department is imposing these assumptions as permit conditions to protect the SO_2 AAAQS/increments

5.7.6. Stack Heights

The compression turbine (**EUs 1 through 6**) stacks and the elevated low-pressure flare (**EU 20**) release will be taller than the exhaust stacks used at the other Nikiski-area stationary sources. Moreover, the assumed stack heights for the power generation turbines (**EUs 7 through 10**), while comparable to those from select nearby sources[28], are significant enough to spatially influence ambient impacts from the Liquefaction Plant. The release heights used in the modeling analysis comply with the stack height requirements listed in 40 CFR 52.21(h) and 18 AAC 50.045(e) – (f), but they are,

[27] EPA Memorandum from Tyler Fox to Regional Air Division Directors, *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard;* 1 March, 2011.

[28] E.g. Tesoro's Kenai Refinery and the Agrium/Nutrien Kenai Nitrogen Plant.

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nevertheless, noteworthy in terms of pollutant transport and building downwash impacts; see the related discussion in Section 5.11 of this report with regard to the latter.

AGDC assumed a physical release height of 63.4 m for the low-pressure flare, which is generally taller than that for comparable units and influential in terms of its diminished interface of the exhaust plume with nearby structures. Similarly, they used modeled stack heights of 64.0 m and 45.7 m for the compression turbines and power generation turbines, respectively. While significant, these assumptions are consistent with the Good Engineering Practice (GEP) requirements in 40 CFR 52.21(h)(1)(i) and 18 AAC 50.045(f)(1).

The Department is imposing the assumed stack heights for the EUs described above as a minimum height requirement to protect the AAAQS and increments. The modeled stack heights are reiterated below in Table 6. The assumed stack heights for the remaining EUs are either within expectations or anticipated to have designs that would maximize downwash, thus obviating the need for explicit stack height conditions.

Table 6. Minimum Stack Height Requirements

EU	Model ID	Description	Min. Stack Height (m)
1 - 6	TURB1 TURB2 TURB3 TURB4 TURB5 TURB6	Treated Gas Compressor Turbines	64.0
7 - 10	TRB_GEN1 TRB_GEN2 TRB_GEN3 TRB_GEN4	Power Generation Turbines	45.7
20	LP_FLARE LP_MAX	Elevated Low-pressure Flare	63.4

5.7.7. Horizontal/Capped Stacks

Capped stacks or horizontal releases generally lead to higher impacts in the immediate near-field than what would occur from uncapped, vertical releases. The presence of non-vertical stacks or stacks with rain caps therefore requires special handling in an AERMOD analysis; see the related discussion in Section 5.8.2 of this report.

AGDC characterized all of the Liquefaction Plant EUs as having uncapped, vertical releases. This is a typical stack design for combustion turbines, however, RICE units, such as AGDC's emergency firewater pump (**EU 11**) and auxiliary air compressor (**EU 12**), can have horizontal releases. Since the impacts from horizontal stacks are typically greater than the impacts from stacks with vertical, uncapped discharges, the Department

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is imposing AGDC's vertical, uncapped assumption for the two RICE, EUs 11 and 12, as an ambient air condition.

5.8. Off-Site Emissions and Stack Parameters

AGDC explicitly modeled the following off-site sources in their cumulative AAAQS/increment analyses:

- Nutrien/Agrium Kenai Nitrogen Operations Plant and Loading Terminal;
- Conoco Phillips Kenai LNG Facility;
- Homer Electric Association Bernice Lake Power Plant;
- Homer Electric Association Nikiski Generation Plant;
- Tesoro Kenai Pipeline Marine Loading Terminal; and
- Tesoro Refinery

They used relevant information from a separate application for a PSD Construction Permit[29] and the Department's 2011 emissions inventory to develop their off-site emission rates and stack parameters for the Liquefaction Plant cumulative impact analyses. For the associated marine vessels, also included in said cumulative analyses, AGDC relied upon Cook Inlet inventory data from 2010, scaled upward for area development, and release parameters assumed to match those of the Liquefaction Plant Marine Terminal vessels. AGDC used the actual emission rates allowed under the Guideline in the annual assessments. The modeled short-term emission rates, along with the characterization of several horizontal/capped stacks, warrants discussion.

5.8.1. Short-Term Emission Rates

Some off-site EUs are authorized to operate continuously on an annual basis. As such, AGDC characterized these EUs with unrestricted emission rates in their ambient demonstrations with one-hour, three-hour, and 24-hour averaging periods. This approach is consistent with Table 8-2 of the 2005 Guideline.

In contrast to the former, however, select off-site units operate intermittently, such as emergency generators and fire water pumps. These units typically have annual operating limits measured in the hundreds-of-hours. The annual emission rates may, therefore, be used to characterize these EUs in the one-hour NO_2 and one-hour SO_2 AAAQS demonstrations per EPA guidance; see Section 5.7.4 of this report. AGDC appropriately used this approach in their one-hour NO_2 and one-hour SO_2 AAAQS demonstrations.

The Department notes that it does not have a written policy germane to the characterization of intermittently operated EUs within an off-site inventory. This lack of policy presents an especially salient challenge when reviewing the modeled characterization of intermittently operated units during short-term averaging periods for

[29] Submitted in support of the Nutrien/Agrium Kenai Nitrogen Operations facility.

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which no EPA guidance exists[30]. The Department understands that AGDC did not want to use an overly conservative characterization of those units subject to restricted operation. However, employing a scaled annual emission rate to characterize short-term AAAQS/increment demonstration units may understate what occurs during those averaging periods. For example, an annual limit of 100 hr/yr, such as that assumed for units subject to a periodic reliability check, is equivalent to a scaled emission rate of about 16 minutes of operation per-day; it is likely such a check would entail greater daily operation in practice.

To generally address the former concerns, the Department more closely examined the reported emissions inventory information for select intermittently operated off-site EUs. It noted that reported information may suggest a more conservative approach exists to characterize the emissions from these EUs during short-term AAAQS/increment demonstrations. However, this difference is sufficiently small such that it is reasonable to anticipate no meaningful impact to the estimated ambient impacts would occur. See the Department's associated findings in the Modeling Report for AGDC's GTP stationary source for detail relevant to this topic.

5.8.2. Characterization of Off-site Horizontal Stacks

As noted in Section 5.7.7 of this report, the presence of non-vertical stacks or stacks with rain caps requires special handling in an AERMOD analysis. While all of the Liquefaction Plant EUs have uncapped, vertical releases, several of the off-site EUs have either horizontal or capped releases.

EPA describes the proper approach for characterizing capped and horizontal stacks in their *AERMOD Implementation Guide*.[31] EPA has also developed an option in AERMOD that will revise the release parameters according to their guidance for any stack identified as horizontal (using the POINTHOR keyword) or capped (using the POINTCAP keyword).

AGDC used the POINTHOR and POINTCAP options to characterize the off-site EUs with horizontal/capped stacks. The option is an approved modeling technique under the 2016 version of the Guideline, but it is considered as an alternative technique under the 2005 version that the Department used for its review; see Section 2.4.3 of this report. AGDC's use of the POINTHOR option therefore requires case-specific approval under 18 AAC 50.215(c).

5.8.2.1 Technical Justification

18 AAC 50.215(c)(1) requires a demonstration that the alternative approach is more appropriate than the preferred air quality model. EPA provided the required demonstration when they promulgated the 2016 version of the Guideline. A

[30] E.g. the probabilistic 24-hour PM-2.5 standard and other short-term deterministic AAAQS/increments.
[31] *AERMOD Implementation Guide* (EPA-454/B-18-003); April 2018.

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summary of this demonstration may be found in the 17 January, 2017 Federal Register notice of the 2016 Guideline (see 82 FR 5182).

5.8.2.2 EPA and Department Approval

18 AAC 50.215(c)(2) requires approval of an alternative modeling technique from the EPA Regional Administrator and the Commissioner's designee. The Commissioner delegated the responsibility for approving alternative modeling methods to the Air Permits Program (APP) Manager on 3 June, 2008.

AGDC noted their desire to use the POINTHOR and POINTCAP options for the cumulative impact analyses in their PSD modeling protocol. The APP Manager approved AGDC's request on 17 November, 2017. R10 approved the request on 12 December, 2017.

5.8.2.3 Public Comment

In addition to complying with the Department's modeling requirements in 18 AAC 50.215(c), PSD applicants must also comply with the PSD modeling requirements in 40 CFR 52.21(l). 40 CFR 52.21(l)(2) says the use of a non-Guideline modeling technique, "*must be subject to notice and opportunity for public comment*." Therefore, the Department is soliciting public comment regarding AGDC's use of the POINTHOR and POINTCAP algorithms in the public notice of the preliminary construction permit.

5.9. Shoreline Fumigation Analysis

Section 7.2.8 of the Guideline describes various complex wind scenarios that may need to be addressed in an air quality modeling analysis. One of those scenarios, shoreline fumigation, warranted assessment in the Liquefaction Plant analysis.

Fumigation "*…occurs when a plume that was originally emitted into a stable layer is mixed rapidly to ground-level when unstable air below the plume reaches plume level*." [32] The phenomena can cause high ground-level concentrations. In coastal areas, fumigation can occur when a plume that is emitted from a tall stack interacts with the "*thermal internal boundary layer*" (TIBL) at some downwind distance. The phenomena is illustrated in Figure 5-6 of Modeling Report, provided as Appendix D to Resource Report 9.

The Liquefaction Plant stationary source will be located on the eastern shore of Cook Inlet. The physical release heights of select EUs at the source, and exhaust plumes in the case of flaring, approach 100 m in height when both the stack and base elevations are considered. The aforementioned factors, therefore, warrant a shoreline fumigation analysis.

[32] Section 4.5.3 of EPA's *Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised* (EPA-454/R-92-019)

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AGDC used the Shoreline Dispersion Model (SDM) to evaluate the impacts of fumigation from the Liquefaction Plant's tall stacks on air quality. Their approach generally entailed an additive process by which SDM-predicted results were combined with their AERMOD output; additional detail on their approach is included in Section 5.8 of AGDC's Modeling Report, provided as Appendix D to Resource Report 9. The Department finds that the potential overstatement of ambient impacts inherent in this approach offers a conservative basis to estimate the aggregate of both in the case of the Liquefaction Plant stationary source. The Department notes that, while the SDM would typically require approval for use as an alternative model under the Guideline, AGDC's use of the tool did not. The reasoning for this is predicated upon its use as a supplement to AERMOD rather than a replacement as discussed in an e-mail[33] between EPA Region 10 and the Department.

5.10. Pollutant Specific Considerations

The following pollutants warrant additional discussion.

5.10.1. Ambient NO_2 Modeling

The NOx emissions from combustion sources are partly nitric oxide (NO) and partly NO_2. After the combustion gas exits the stack, additional NO_2 can be created due to atmospheric reactions. Section 5.2.4 of the Guideline describes a tiered approach for estimating the resulting annual average NO_2 concentration, ranging from the simplest but very conservative assumption that 100 percent of the NO is converted to NO_2, to other more complex methods. These approaches are also generally applicable in modeling the one-hour NO_2 impacts.

AGDC used ARM2 to estimate their ambient NO_2 concentrations, as previously noted in Section 5.2.1 of this report. ARM2 is an EPA-approved modeling technique under the 2016 version of the Guideline, but it is considered as an alternative technique under the 2005 version; see Section 2.4.3 of this report. ARM2, therefore, requires case-specific approval under 18 AAC 50.215(c). Applicants also have the option of using a non-default MAR. Each of these aspects is further discussed below.

5.10.1.1 Procedural Requirements

As previously discussed in Section 5.8.2.1 of this report, 18 AAC 50.215(c)(1) requires a demonstration that the alternative approach is more appropriate than the preferred air quality model. EPA provided the required demonstration when they promulgated the 2016 version of the Guideline (see 82 FR 5182).

18 AAC 50.215(c)(2) requires EPA Region 10 and Department approval of the alternative modeling technique. The Air Permits Program Manager approved AGDC's request to use ARM2 on 20 November, 2017, and Region 10 approved the request on 12 December, 2017.

[33] Email from Jay McAlpine (EPA R10) to Alan Schuler (Department) and George Bridgers (EPA), *RE: Quick update on our status for Alaska LNG*; 6 December, 2017.

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5.10.1.2 Minimum Ambient Ratio

ARM2 uses empirically derived ambient ratios of NO_2/NOx conversion in its application of a ratio for modeled NOx concentrations. The default upper- and lower-bounds for this applied ratio in a model are 0.9 and 0.2, respectively.

AGDC used the default lower-bound of 0.2 in their analysis. Their basis for the use of this ratio is predicated upon the assertion it is representative of in-stack conversion for the EUs dominating impacts at the Liquefaction Plant. They further assert that, while select units may be characterized by higher conversion ratios, those most culpable for one-hour NO_2 impacts are likely to possess sub-0.2 ratios. In further support of their use of the minimum ratio, AGDC cites EPA guidance[34] indicating that full-conversion results within 150 to 200 parts-per-billion by volume (ppbv) are anticipated to be conservative when using ARM2, irrespective of the assumed ratio. AGDC's Tier 1 results, as reported in their application, offer a full-conversion NO_2 impact of approximately 134 ppbv.

The Department is aware of source test data that suggest turbines, flares, and RICE equipped with catalyzed diesel particulate filters may possess in-stack ratios above 0.2. Moreover, AGDC's modeling assumptions for the GTP stationary source, which employ the Plume Volume Molar Ratio Method (PVMRM) to estimate ambient NO_2 impacts, reflect a generally higher set of conversion ratios for similar EUs. A Departmental review of source-group categorized impacts and model outputs, however, alongside the relative conservatism of ARM2 vs PVMRM estimated impacts, is sufficient to find AGDC's use of ARM2 and its assumed default ratios appropriate on a case-specific basis for the Liquefaction Plant stationary source.

5.10.2. PM-2.5

PM-2.5 is either directly emitted from a source or formed through chemical reactions in the atmosphere (secondary formation) from other pollutants (NOx and SO_2).[35] AERMOD is an acceptable model for performing near-field analyses of the direct emissions, but EPA has not developed a near-field model that includes the necessary chemistry algorithms for estimating the secondary impacts. They instead issued guidance as to how secondary formation could be accounted for under the 2005 version of the Guideline.[36]

EPA noted that the maximum direct impacts and the maximum secondary impacts from a stationary source "*...are not likely well-correlated in time or space*", i.e., they will likely occur in different locations and at different times. This difference occurs because

[34] EPA Memorandum from OAQPS, *Clarification on the Use of AERMOD Dispersion Modeling for Demonstrating Compliance with the NO2 National Ambient Air Quality Standard*; 30 September, 2014.
[35] The NOx and SO_2 emissions are also referred as "precursor emissions" in a PM-2.5 assessment.
[36] *Guidance for $PM_{2.5}$ Permit Modeling* (EPA-454/B-14-001); May 2014.

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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 Liquefaction Plant EUs occur.

AGDC used representative ambient monitoring data to address their near-field secondary PM-2.5 formation from off-site sources in comport with EPA guidance; see the associated discussion in the Department's Modeling Report for the GTP stationary source for relevant detail. In supplemental support of the former approach, AGDC also evaluated the potential impact from secondary PM-2.5 formation using the CALPUFF model and its POSTUTIL post-processor. The analytical methodology of this approach generally entails an examination of precursor emissions and their anticipated PM-2.5 impacts. A more detailed discussion of this approach is presented in Section 8.5 of AGDC's Modeling Report, provided as Appendix D to Resource Report 9. The Department finds that this approach is appropriate to generally characterize the impact of secondary PM-2.5 formation at the Liquefaction Plant stationary source.

5.11. Downwash

Downwash refers to the situation where local structures influence the plume from an exhaust stack. Downwash can occur when a stack height is less than GEP, which is defined in 18 AAC 50.990(42). It is a consideration when there are receptors relatively near the applicant's structures and exhaust stacks.

EPA developed the "Building Profile Input Program – PRIME" (BPIPPRM) program to determine which stacks could be influenced by nearby structures and to generate the cross-sectional profiles needed by AERMOD to determine the resulting downwash. AGDC used the current version of BPIPPRM, version 04274, to determine the building profiles needed by AERMOD for the Liquefaction Plant EUs.

The Department used a proprietary 3-D visualization program to review AGDC's modeled characterization of the exhaust stacks and structures. Their characterization of the Liquefaction Plant EUs are representative of the layout shown in Figure 5-5 of Appendix D to Resource Report 9. AGDC's characterization of the off-site sources and/or building configurations also appear to represent the facility layouts on file from previous submissions. BPIPPRM indicated that the GTP exhaust stacks are within the GEP stack height requirements.

5.12. Ambient Air Boundary

The AAAQS and increments only apply in *ambient air* locations, which has been defined by EPA as, "*…that portion of the atmosphere, external to buildings, to which the general public has access*." [37] Applicants may, therefore, exclude areas that they own or lease from

[37] The term "ambient air" is defined in 40 CFR 50.1. The Alaska Legislature has also adopted the definition by reference in AS 46.14.90(2).

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their ambient demonstration if public access is "*precluded by a fence or other physical barrier*." [38]

AGDC used the proposed fenced perimeter around the Liquefaction Plant as an ambient air quality boundary for the on-shore facility area. They also excluded the marine vessel loading berths and trestle areas from ambient air assuming a 500-foot stand-off distance predicated upon reasonable and enforceable safety requirements. The former element of AGDC's approach offers a clear means to preclude the public from ambient air. The latter element of this approach, while not supported by explicit and quantifiable air quality guidance, is rooted in practical precedent. The Department's discussion in the Ambient Boundary section of its Modeling Report for PacRim Coal, LLC's Chuitna Project, Minor Permit AQ0957MSS03, offers relevant detail regarding the exclusion of vessel loading activities from ambient air. AGDC's approach to exclude select areas from ambient air is appropriate for the Liquefaction Plant ambient analysis.

5.13. Receptor Grid

A dispersion model will calculate the concentration of the modeled pollutant at locations defined by the user. These locations are called receptors. Designated patterns of receptors are called receptor grids.

AGDC described their receptor grid in Section 5.4 of Appendix D to Resource Report 9. In summary, AGDC used a Cartesian receptor grid of decreasing resolution with distance from the ambient boundary for their project impact analysis. The modeled receptor resolutions are:

- 25 m resolution along both the Liquefaction Plant fence line and off-site facility fence lines;
- 25 m resolution along the edge of AGDC's 500 foot marine vessel and trestle exclusion zone;
- 25 m resolution from the previous boundaries to a outward distance of 200 m;
- 50 m resolution from 200 m to an outward distance of 500 m;
- 100 m resolution from 500 m to an outward distance of 1 km;
- 250 m resolution from 1 km to an outward distance of 2.5 km;
- 500 m resolution from 2.5 km to an outward distance of 5 km;
- 1 km resolution from 5 km to an outward distance of 10 km; and
- 2 km resolution from 10 km to an outward distance of 20 km.

[38] EPA has written a number of guidance documents regarding ambient air issues which may be found in their Modeling Clearinghouse Information Storage and Retrieval System (http://cfpub.epa.gov/oarweb/MCHISRS/). The documents routinely use the phrase "fence or other physical barrier" when discussing an acceptable means for precluding public access at onshore locations. The phrase originated in a December 19, 1980 letter from EPA Administrator Douglas Costle to Senator Jennings Randolph.

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AGDC's receptor grid has sufficient resolution and coverage to determine the maximum impacts. The maximum impacts generally occur near the Liquefaction Plant facility.

5.14. Off-Site Impacts

The air quality impact from natural and regional sources, along with long-range transport from far away sources, must be accounted for in a cumulative AAAQS demonstration. The increment consuming impact from nearby off-site anthropogenic sources must likewise be accounted for in a cumulative increment demonstration. The approach for incorporating these impacts must be evaluated on a case-specific basis for each type of assessment and for each pollutant.

The off-site facilities enumerated Sections 5.1 and 5.8 of this report are close enough to have significant concentration gradients in the vicinity of the Liquefaction Plant. AGDC, therefore, included these sources in their cumulative AAAQS/increment analyses. They used ambient NO_2, SO_2, and CO data collected during their pre-construction monitoring effort, and PM-10, PM-2.5, and O_3 data collected by Nutrien/Agrium for the nearby Kenai Nitrogen Operation stationary source, to represent the impacts from all other sources in their cumulative analyses not explicitly modeled; see Section 4 of this report for details of these data collection efforts. In summary, AGDC's selection of off-site sources, and the contemporaneous superposition of PSD-quality background data, are sufficient to represent the air quality impacts from natural and anthropogenic sources in the project area.

5.15. Modeled Design Concentrations

EPA allows applicants to use modeled concentrations that are consistent with the form of the given standard or increment as their design concentrations. The highest concentrations must generally be used when comparing the modeled impacts to the SILs. However, the multi-year average of the highest concentrations may be used when comparing the one-hour NO_2, one-hour SO_2, 24-hour PM-2.5, and annual PM-2.5 impacts to the SILs – for purposes of demonstrating compliance with the AAAQS.[39] AGDC used the modeled concentrations that are consistent with the above description. The design concentrations used in AGDC's cumulative modeling analyses to demonstrate compliance with the AAAQS and Class II increments are summarized in Table 7.

Table 7. AGDC's Approach for Determining the Modeled Design Concentrations

Pollutant	Avg. Period	AAAQS	Class II Increment
NO_2	one-hour	h8h	--
	Annual	HY	HY
PM-10	24-hour	h6h	h2h
	Annual	--	HY

[39] The maximum value from any year must be used for the other pollutants and averaging periods, and when comparing the 24-hour PM-2.5 and annual PM-2.5 impacts to the SILs for purposes of demonstrating compliance with the Class II increments.

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PM-2.5	24-hour	h8h	h2h
	Annual	MA	HY
SO_2	one-hour	h4h	--
	three-hour	h2h	h2h
	24-hour	h2h	h2h
	Annual	HY	HY
CO	one-hour	h2h	--
	eight-hour	h2h	--

Table Notes:

h2h = the maximum high second-high concentration from any year.

h4h = the multi-year average of the high fourth-high daily maximum one-hour concentrations.

h6h = the high sixth-high 24-hour concentration over five years.

h8h = high eighth-high. For purposes of one-hour NO_2, the h8h is the five-year average of the high, eighth-high of the daily maximum one-hour NO_2 concentrations. For purposes of 24-hour PM-2.5, the h8h is the five-year average of the high, eighth-high of the 24-hour PM-2.5 concentrations.

HY = highest annual average from any year.

MA = highest multi-year average of the annual concentrations at a given receptor.

-- = there is no AAAQS/increment (as applicable) for this pollutant/averaging period.

6. NEAR-FIELD MODELING RESULTS AND DISCUSSION

The maximum project impacts are presented in Table 8. The SIL for each pollutant and averaging period is also presented for comparison. The maximum impacts exceed the applicable SIL for most pollutants and averaging periods; the annual SO_2 is the exception. Therefore, the Liquefaction Plant emissions will not cause or contribute to a violation of the annual SO_2 AAAQS or Class II increments.

Table 8. Maximum Project Impacts Compared to the SILs

Pollutant	Avg. Period	Max. Modeled Conc. ($\mu g/m^3$)	SIL ($\mu g/m^3$)
NO_2	one-hour	140.1	8
	Annual	8.4	1
SO_2	one-hour	57.5	8
	three-hour	39.6	25
	24-hour	17.1	5
	Annual	0.11	1
PM-2.5 (multi-year avg.)	24-hour	3.6	1.2
	Annual	0.38	0.3

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PM-2.5 (max. impact from any year)	24-hour	4.8	1.2
	Annual	0.43	0.3
PM-10	24-hour	24.7	5
	Annual	2.7	1
CO	one-hour	2,721	2,000
	eight-hour	1,071	500

Table Note: The multi-year average of the maximum PM-2.5 impacts may be compared to the PM-2.5 SILs for purposes of demonstrating compliance with the PM-2.5 AAAQS. However, the maximum PM-2.5 impact from any year must be compared to the PM-2.5 SILs for purposes of demonstrating compliance with the PM-2.5 increments. (See Section 5.15 of this report.)

The results from the cumulative AAAQS analyses are presented in Table 9. The background concentrations, total impact, and AAAQS are also shown. All of the total impacts are less than the AAAQS.

Table 9. Maximum Impacts Compared to the AAAQS

Pollutant	Avg Period	Modeled Design Conc. (μg/m³)	Max. one-hour Fumigation Conc. (μg/m³)	Bkgd Conc. (μg/m³)	Total Impact (μg/m³)	AAAQS (μg/m³)
NO_2	one-hour	149.5	Included	32.3	**181.8**	188
	Annual	20.4	34.1	2.6	**57.1**	100
PM-10	24-hour	23.9	5.0	40	**68.9**	150
PM-2.5	24-hour	6.4	5.0	12	**23.4**	35
	Annual	2.8	5.0	3.7	**11.4**	12
CO	one-hour	2,721	78.3	1,145	**3,945**	40,000
	eight-hour	1,071	78.3	1,145	**2,294**	10,000
SO_2	one-hour	63.4	5.7	5.0	**74.1**	196
	three-hour	50.6	5.7	5.0	**61.3**	1,300
	24-hour	32.0	5.7	2.4	**40.1**	365

Table Note: The one-hour NO_2 background concentration is included in the modeled concentration.

The results from the cumulative Class II increment analysis are presented in Table 10. The modeled design concentrations are less than the Class II increment for all pollutants and averaging periods.

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Table 10. Maximum Modeled Impacts Compared to the Class II Increments

Pollutant	Avg. Period	Modeled Design Conc. (μg/m³)	Max. one-hour Fumigation Conc. (μg/m³)	Total Impact (μg/m³)	Class II Increment (μg/m³)
NO_2	Annual	12.5	Included	12.5	25
PM-10	24-hour	24.7	5.0	29.7	30
	annual	2.7	5.0	7.7	17
PM-2.5	24-hour	8.7	Included	8.7	9
	Annual	1.3	Included	1.3	4
SO_2	three-hour	39.6	5.7	45.4	512
	24-hour	17.5	5.7	23.3	91

7. CLASS I ANALYSES

In accordance with 40 CFR 52.21(p), PSD applicants must perform a Class I Impact Analysis, for stationary sources that may affect a Class I area. As broached in Section 2.1, the Class I areas nearest the Liquefaction Plant are Tuxedni, managed by the US FWS, and Denali, managed by the NPS. Tuxedni is located 86 km to the south, and Denali approximately 183 km to the north. The following describes AGDC's approach with regard to the Class I increment and AQRV.

7.1. Class I Increment Analysis

There are no Class I areas within 50 km of the Liquefaction Plant. The nearest Class II Sensitive area, Kenai National Wildlife Refuge (Kenai NWR), however, is situated approximately 10 km distant. AGDC, nevertheless, performed near-field analyses of their increment impacts using AERMOD. The source-only and cumulative results, provided previously in this report, do not suggest meaningful ambient concentration gradients attributable to the Liquefaction Plant exist beyond the immediate near-field of the stationary source. Moreover, all results indicate estimated ambient concentrations within the modeled areas of concern fall below the respective increments.

AGDC used the EPA's approved CALPUFF model, along with its associated pre- and post-processing tools, to evaluate their far-field impacts at the Tuxedni and Denali Class I areas. They additionally evaluated impacts at several Class II Sensitive areas[40] within their modeled domain. A detailed discussion germane to AGDC's selection and development of far-field model inputs and outputs is provided in Section 6 of their Modeling Report, included as Appendix D to Resource Report 9. AGDC's far-field model results, both source-only and cumulative, indicate estimated ambient concentrations within the modeled areas of

[40] The Class II Sensitive areas subject to evaluation include the Kenai NWR, Chugach National Forest, Lake Clark National Park and Preserve, Kenai Fjords, and Kodiak National Wildlife Refuge.

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concern fall below the respective increments; no violations of the NAAQS/AAAQS are seen.

7.2. Class I AQRV Analysis

AGDC performed a near-field assessment, to evaluate the impact of non-collocated plumes as compared to background viewing, and a far-field assessment, with regard to impacts to regional views.

There are no Class I areas within 50 km of the Liquefaction Plant. AGDC, nevertheless, evaluated plume visibility at the Kenai NWE[41], which is situated within 50 km, using EPA's VISCREEN model, a screening-level plume visibility tool. The VISCREEN model, drawing upon user-provided environmental variables, provides an analytical estimation of visual impairment through both the plume contrast and plume perceptibility parameters. Details of AGDC's assumed near-field model variables and VISCREEN-observed EU plume combinations is provided in Sections 6.6 and 7.2.4.1 of their Modeling Report, included as Appendix D to Resource Report 9. The results of AGDC's VISCREEN analysis at the Kenai NWR indicate that nearly all modeled visibility parameters fall below their associated criteria. The exceptions include:

- A slight deviation from both criteria for the compressor turbine plumes, subject to sky background and backward scatter, at the closest park boundary observer location; and
- An increase in the perceptibility criteria for the compressor turbine plumes, subject to terrain background and forward scatter, at both the closest park boundary and Skilak Lake observer locations.

It is reasonable to consider the former deviances negligible given representative-to-conservative model inputs and the level of uncertainty inherent at this resolution of modeled result. Moreover, the relative isolation of these estimated deviances at a Class II Sensitive area is not sufficient to warrant further regulatory inquiry, *ceteris paribus*. Therefore, the Department finds AGDC's modeled results sufficient to provide a reasonable estimation of immaterial near-field visibility impacts.

AGDC used the EPA's approved CALPUFF model, along with its associated pre- and post-processing tools, to evaluate their far-field impacts at the nearest Class I areas. They also included impacts at several Class II Sensitive areas situated within their modeling domain. Their CALPUFF evaluation included assessments of ambient concentration, visibility, and acidic deposition. A detailed discussion germane to AGDC's selection and development of far-field model inputs and outputs is provided in Sections 6, 7.2.4.2, and 7.2.4.3 of their Modeling Report, included as Appendix D to Resource Report 9.

AGDC's model-estimated source-only impacts to both Class I and Class II Sensitive areas, in terms of regional haze and visibility degradation, fall below the five-percent extinction

[41] The Kenai NWR is designated as a Class II Sensitive area for the purposes of air quality assessments.

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threshold at all areas evaluated, save slight exceedances at Lake Clark National Park in model years 2003 and 2004. When considering a cumulative analysis, however, the model predicts exceedances of the 10-percent extinction criteria at all locations. The Department understands that these cumulative values may be compelling when considered in the absence of additional information. However, AGDC's source-only results suggest there is no cause for regulatory concern at the former areas with regard to significant visibility impairment attributable to operation of the Liquefaction Plant as proposed. Furthermore, mode uncertainty and conservative operational assumptions suggest estimated impacts attributable to the Liquefaction Plant may be overstated. Therefore, the Department finds AGDC's modeled results sufficient to provide a reasonable estimation of immaterial far-field visibility impacts.

AGDC's source-only deposition analysis indicates sulfur and nitrogen flux results above the respective deposition analysis thresholds (DATs) at several locations; Denali is the only Class I area among the former. Their cumulative deposition analysis yield results below the DAT at all locations. The Department notes that among those locations with higher source-attributable estimated deposition impacts, only sulfur appears to boast impacts that are meaningfully above the DATs while nitrogen remains marginally above said thresholds. The Department notes that AGDC's position regarding an in-situ potential for "sweeter" than modeled pipeline-quality fuel gas and conservative operational assumptions would likely obviate the sulfur deposition concerns at the Class II Sensitive areas modeled. It further notes that said conservativism of operational assumptions, largely predicated upon AGDC's greater than anticipated 'normal' modeled operational scenario, would similarly mitigate their source-attributable nitrogen deposition impacts. Therefore, the Department finds AGDC's modeled results sufficient to provide a reasonable estimation of immaterial acidic deposition impacts.

8. OZONE IMPACTS

As discussed in Section 1 of this report, VOC is a triggered PSD-pollutant for the Liquefaction Plant project. There is AAAQS for VOC, but its emissions, and those of NOx, can form O_3, which does have an AAAQS. AGDC was, therefore, required to demonstrate compliance with the O_3 AAAQS per 40 CFR 52.21(k).

O_3 is not usually emitted directly into the air. It is instead created in the atmosphere through chemical reactions between NOx and VOC in the presence of sunlight. It is inherently a regional pollutant, the result of chemical reactions between emissions from many NOx and VOC sources over a period of hours or days, and over a large area.

The 2005 version of the Guideline does not list a recommended model for assessing the O_3 impact from an individual stationary source. Qualitative approaches are instead generally used to meet the 40 CFR 52.21(k) ambient demonstration requirement.

AGDC provided a background discussion regarding O_3 formation in Section 8 of the Liquefaction Plant Modeling Report, provided as Appendix D to Resource Report 9. The

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discussion includes a trajectory analysis for days with "elevated" ozone concentrations using the HYSPLIT model. They also discussed several lower-48 Photochemical Grid Model (PGM) ozone analyses, and what the findings could mean with respect to the Liquefaction Plant project.

The Department did not take the time to review AGDC's trajectory analysis or PGM discussion noting the following aspect of their O_3 demonstration. AGDC provided an analytical discussion and tabular data in their response to the Department's 17 January, 2018 Modeling Protocol approval. This information is provided in Attachment 3 to Resource Report 9. The discussion and data, in conjunction with the associated conceptual methodology observed by the Department in its Modeling Report for GTP, suggest the Liquefaction Plant project is not anticipated to cause or contribute to a violation of the eight-hour O_3 AAAQS.

9. ADDITIONAL IMPACT ANALYSES

PSD applicants must assess the impact from the proposed project and associated growth on visibility, soils, and vegetation, per 40 CFR 52.21(o) – *Additional Impact Analyses*. AGDC provided their additional impact analyses in Attachment 10 to Resource Report 9. The Department's findings regarding their analyses are reported below.

9.1. Associated Growth Analysis

40 CFR 52.21(o)(2) requires PSD applicants to "*provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source or modification*." AGDC does not expect industrial or commercial growth in the immediate vicinity of the Liquefaction Plant as it is planned to fit within the current area infrastructure. With respect to employment, AGDC stated that they anticipate the eventual creation of 300 jobs. While this would lead to some residential growth, the number represents approximately two-percent of the current area population based upon 2010 U.S. Census figures. As such, the concomitant increase in emissions associated with residential growth would likely yield insignificant impacts on soils, vegetation, and visibility. The Department, therefore, finds AGDC's assessment reasonable for the Liquefaction Plant.[42]

9.2. Visibility Impacts

PSD applicants must assess whether the emissions from their stationary source, including associated growth, will impair visibility. Visibility impairment means any humanly perceptible change in visibility, such as visual range, contrast, or coloration, from that which would have existed under natural conditions. Visibility impacts can occur as visible plumes, i.e., "plume blight," or in a general, area-wide reduction in visibility, also known as "regional haze". Alaska does not have standards for plume blight. For Class I areas, the

[42] AGDC did not include the Pipeline Stations and Gas Treatment Plant in their Associated Growth Analyses since those stationary sources will not be located in the same area as the Liquefaction Plant. As previously noted in Section 5.6.3 of this report, the ambient impacts associated with each of those stationary sources will be assessed, as warranted, under the permit requirements for that stationary source.

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Federal Land Manager provides the desired thresholds. There are no established thresholds for Class II areas. The typical tool for assessing plume blight is EPA's VISCREEN model.

The maximum range of VISCREEN is 50 km. When Class I areas lie beyond that range, as in the case at hand, the Department recommends that the applicant use the 50 km maximum range as the source to observer distance. This approach provides the upper bound of the potential plume blight impacts at more distance locations. This same distance (50 km) would also be used as the "nearest" source to boundary distance per page 24 of EPA's *Workbook for Plume Visual Impact Screening and Analysis (Revised).*[43]

Since there are no Class II visibility thresholds, VISCREEN compares the visibility impacts to the Class I thresholds. VISCREEN provides results for impacts located inside a Class I area and for impacts located outside a Class I area. The latter is used in situations where there is an "integral vista." In situations where there are no integral vistas, applicants only need to use the results for impacts located inside a Class I area. Alaska only has two integral vistas, both of which are associated with Denali National Park. Since the integral vistas are well beyond the 50 km range of VISCREEN, the Department informed AGDC that they only needed to report the "inside" results. A discussion regarding AGDC's visibility analysis is presented in Section 7.2 of this report. The Department did not require AGDC to conduct a more rigorous visibility analysis since there are no plume blight thresholds for Class II areas.

9.3. Soil and Vegetation Impacts

The ambient demonstration provided by applicants is typically adequate for showing that their air emissions will not cause adverse soil or vegetation impacts. Congress established "primary" NAAQS and "secondary" NAAQS in Section 109(b) of the Clean Air Act. The primary NAAQS protect public health, while the secondary NAAQS protect public welfare. Congress further stated in Section 302(h) of the CAA, "*All language referring to the effects of **welfare** includes, but is not limited to, effects on **soils**, water, crops, **vegetation**, ...*" (emphasis added).The AAAQS and primary NAAQS are identical for each of the modeled pollutants. However, the annual PM-2.5 secondary NAAQS (15 $\mu g/m^3$) is less stringent than the annual PM-2.5 primary NAAQS/AAAQS (12 $\mu g/m^3$). Therefore, a modeling analysis that demonstrates compliance with the AAAQS also demonstrates compliance with the secondary NAAQS.

AGDC demonstrated that they can comply with the primary AAAQS. They summarized this information in Table 1 of Attachment 10 to Resource Report 9. Therefore, their ambient analysis generally demonstrates that they will not have adverse soil or vegetation impacts.

10. CONCLUSIONS

The Department concludes the following based on its review of AGDC's permit application and ambient demonstrations:

[43] *Workbook for Plume Visual Impact Screening and Analysis (Revised),* (EPA-454/R-92-023); October 1992.

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1. AGDC's characterizations of the proposed exhaust stacks comply with the stack height and dispersion requirements described in 40 CFR 52.21(h) ***Stack Heights***.
2. AGDC's ambient demonstration satisfies the ***Source Impact Analysis*** requirements of 40 CFR 52.21(k). AGDC demonstrated that the NOx, SO_2, PM-10, PM-2.5, CO, and VOC emissions associated with operating the stationary source, within the restrictions listed in this report, will not cause or contribute to a violation of the NO_2, SO_2, PM-10, PM-2.5, CO, and O_3 AAAQS. They also demonstrated that the emissions will not cause or contribute to a violation of the NO_2, SO_2, PM-10, and PM-2.5 Class I or II increments.
3. AGDC appropriately used the models and methods required under 40 CFR 52.21(l) ***Air Quality Models***.
4. AGDC conducted their modeling analysis in a manner consistent with the Guideline, as required under 18 AAC 50.215(b)(1).
5. The 2018 to 2019 ambient pollutant data collected by AGDC at the project site, and 2013 to 2014 data collected by Nutrien/Agrium for the nearby Kenai Nitrogen Operation project, satisfies the ***Preapplication Analysis*** requirements of 40 CFR 52.21(m)(1).
6. AGDC provided the ***Additional Impact Analyses*** required under 40 CFR 52.21(o).

The Department developed permit conditions in Construction Permit AQ1539CPT01 to ensure AGDC complies with the AAAQS and Class II increments. These conditions are *summarized* as follows:

- To protect the NO_2, CO, PM-10, PM-2.5, and SO_2 AAAQS, and the NO_2, PM-10 and PM-2.5 Class II increments:

  Stack Configuration

  - Construct and maintain vertical, uncapped exhaust stacks for **EUs 11 – 12** and on all temporary construction RICE EUs. AGDC may use flapper-style rain covers, or other similar designs, that do not hinder the vertical momentum of the exhaust plume.

  Stack Heights

  - Construct and maintain exhaust stacks with release points above the base elevation that equals or exceeds the minimum height listed in Table 6 for that EU.

- To protect the one-hour and annual NO_2 AAAQS, the one-hour and annual SO_2 AAAQS, the annual PM-2.5 AAAQS, the annual NO_2 Class II increment, the annual SO_2 Class II increment, the annual PM-10 Class II increment, and the annual PM-2.5 Class II increment:
  - Limit the operation of **EUs 11 and 12** to 500 hr/yr.
- To protect the 24-hour PM-10 AAAQS, the 24-hour PM-2.5 AAAQS, and the annual PM-2.5 AAAQS during the construction phase:

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- Use the best management practices described in the permit to minimize the fugitve dust emissions from construction activities.
- Install and operate one or more air quality monitoring stations to measure the actual PM-2.5 and PM-10 ambient concentrations. Take additional actions to reduce the fugitive dust emissions if the AAAQS become threatened.

- To protect the one-hour, three-hour, 24-hour, and annual SO_2 AAAQS; and the three-hour, 24-hour, and annual SO_2 Class II increments:
  - Limit the sulfur content of the liquid fuels fired to no greater than 15 ppmw; and
  - Limit the total sulfur content of the fuel gas fired to no greater than 16 ppmv.

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DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY CONSTRUCTION PERMIT
RESPONSE TO COMMENTS

Owner Name: Alaska Gasline Development Corporation
Permit No.: AQ1539CPT01
Public Comment Closing Date: December 10, 2020
Source Name: Liquefaction Plant

Prepared by Dave Jones on July 7, 2022

This document provides the Alaska Department of Environmental Conservation's (Department's) response to all public comments on its preliminary decision to issue Air Quality Control Construction Permit AQ1539CPT01 to Alaska Gasline Development Corporation (AGDC) for the Liquefaction Plant. The Department provided an opportunity for public comment on its preliminary decision beginning September 11, 2020 and ending December 10, 2020.

The Department received numerous public comments on the preliminary permit decision, the majority of which were submitted by Sara Laumann on behalf of the National Parks Conservation Association, Center for Biological Diversity, and Northern Alaska Environmental Center (collectively referred to as NPCA in this document). Additional comments were received from EPA Region 10 (EPA), National Park Service (NPS), Chickaloon Village Traditional Council (Chickaloon), and AGDC. The substantial number of comments are similar enough in scope that the Department has chosen to organize this Response to Comments document by topic, rather than commenter.

The table of contents presents each topic under general categories to make them easier to find. This organizational structure for the comments does not necessarily mean sub-categories are related. Air quality is a complex topic and the various sub-categories do affect one another.

All of the comments in the document are verbatim, except for the comments received from NPCA and NPS which were in a narrative form and too substantial to include in their entirety. The Department has therefore summarized the NPCA and NPS comments and uses quotation marks to indicate any direct quotes. The primary NPCA and NPS comment documents are also attached to the end of this Response to Comments document as Attachments A and B respectively.

The **categories** are designated by **14-point bold font**. The **topics** are designated by **12-point bold font**. The comments are in regular 12-point font. The Department's *responses are in 12-point italics.*

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1. Regulatory Basis for Approving a Construction Permit

The regulatory standard for approval or denial of a construction permit is based on whether the permit meets the regulatory provisions in Title 18 of the Alaska Administrative Code – Chapter 50 (18 AAC 50). The Department has confined this response to comment document to those comments that are related to whether the applicant and the Department has or has not complied with the air quality permitting requirements contained in 18 AAC 50.

2. Comments on NOx BACT Analyses for Gas-Fired Turbines

The Department received comments on the following aspects of the NOx Best Available Control Technology (BACT) analysis for the gas-fired turbines.

2.1. Several commenters recommend that the Department reconsider the AKLNG NOx BACT determination for the combustion turbines in light of: modeled nitrogen deposition, other facilities nearby equipped with SCR, other states setting BACT cost thresholds lower than those in the preliminary permit, and updated cost analyses re-

calculated using the 7th edition of the EPA Control Cost Manual, and commonly selected NOx BACT emission rates for similar units. These comments also provide information related to interest rates, reagent costs, cost year, electricity costs, SCR inlet temperatures and several other considerations

Department Response: On April 13, 2022, AGDC provided the Department with an application addendum revising their NOx BACT proposal for the gas fired turbines EUs 1 – 10. The new proposal recommends the top NOx emissions control of Selective Catalytic Reduction (SCR) with an emission limit of 2 ppmv at 15% O_2. Therefore, the Department revised the NOx BACT requirements for EUs 1 – 10 in the permit and TAR to require SCR with an emissions limit of 2 ppmv at 15% O_2. Now that the Permittee has recommended, and the Department has selected the top NOx emissions control of SCR as BACT, the Department has removed the economic analyses for SCR from the TAR.

2.2. NPCA Commented – "The BACT analyses for the six compressor turbines and the four power turbines are flawed because the draft permit fails to identify the make and model of each turbine to be installed, which is necessary to know achievable emission rates for several pollutants including greenhouse gases and NOx.[1]"

Department Response: The Liquefaction Plant is still multiple years away from commencing construction and the Permittee has not yet selected the make and model of turbines to be installed at the stationary source. However, this does not preclude the Department from issuing a PSD permit and selecting BACT emissions rates for emissions units based upon what is commercially available and installed at other stationary sources around the country. It must also be noted that under the current definition of "begin actual construction" (40 CFR 52.21(b)(8), (9) & (11)), the owner or operator needs to have permits in-hand (9) prior to commencing a continuous program of actual on-site construction including ((9)(ii)) "binding agreements or contractual obligations" such as ordering major components of emissions units such as turbines.

The footnote to this comment references that switching to another fuel or raw material would distort a prior air quality assessment, however the Department notes that there will be no switching to another fuel type and that the BACT determination requires the turbines at the stationary source to exclusively combust natural gas.

The comment also goes on to state that for the combined cycle turbines, the heat input should be stated if duct firing is included with the heat recovery steam

[1] A policy reason for requiring PSD review, in addition to those discussed in preceding sections, is that subsequent PSD permits to other sources are premised on stability - and accuracy in determining - of the level of emissions from existing sources (in another context, the preamble to the 1980 PSD regulations explained the need for such accuracy and stability "[i]n EPA's view, any switch to another fuel or raw material that would distort a prior assessment of a source's air quality impact should have to undergo [PSD] scrutiny." 45 Fed. Reg. 52,676, 52,704 (1980).

generator. The Department notes that there is no supplemental duct firing burners included with the heat recovery steam generator in the combined cycle turbines.

3. Greenhouse Gas BACT Analyses for Carbon Capture and Storage (CCS)

3.1. Several Commenters provided comments indicating that the Department improperly eliminated CCS from its greenhouse gas BACT findings.

Department Response: The Department contacted the Alaska Department of Natural Resources (DNR) who stated that, as of July 1, 2022, "At this time, the state does not have the regulatory framework to permit the leasing of its lands for CCUS projects." *Thus there is no viable commercially-operating CCUS facility within reasonable geographic proximity for internment of CO_2 sequestration in underground storage.*

It should be noted that no LNG plant has been required to install CCUS as part of a PSD BACT determination and no currently operating LNG plant utilizes CCUS. Currently, there is no available resource for CCUS projects available in Alaska. There is no existing infrastructure, and to expect the stationary source to propose, license and construct such a facility is redefining the source. In addition to the regulatory framework, there is still a great deal of work remaining to delineate the CCUS potential of the state, particularly in the Cook Inlet. Therefore, the Department finds that installation of CCUS is not technically feasible to compress, transport, and inject CO_2 at any location accessible to the GLF stationary source.

4. Other BACT Comments

4.1. EPA Commented – **Reliance on the RBLC.** Review of Review of the documents indicates both ADEC and the proponent relied exclusively on the EPA RACT-BACT-LAER Clearinghouse (RBLC) in their efforts to identify "available" control technologies for many emission units and pollutants. Region 10 would like to note that due to several factors, including incomplete data entry, the RBLC cannot be considered a comprehensive database for all available control technologies. Proponents and reviewing agencies should expand their review and consider a wider search approach for available technologies beyond those listed in the RBLC, particularly including those implemented on similar emission units that may be identified via state BACT information, contact with control equipment vendors, or other web research.

Department Response: The Department did extensive research related to potential control equipment that includes sources other than the RBLC to determine technically feasible control equipment for the Liquefaction Plant. This includes several recent PSD permits from around the country, research related to positive crankcase ventilation, CCS options, as well as broad variety of search methods. It notes that future PSD BACT evaluations will continue to use a wide variety of search approaches to find the most relevant and available technologies beyond those listed

in the RBLC. The Department has also recommended that EPA create a greenhouse gas chapter in the cost control manual for additional informational related to up-and-coming control options.

4.2. EPA Commented – **Opacity BACT.** ADEC should consider imposing a five or ten percent opacity limit on all emission units as part of the BACT particulate matter requirements. The state regulation twenty percent opacity standard is so high as to be ineffective as an indicator of excess emissions (above BACT emission limits).

Department Response: The Department has included requirements to limit opacity from the gas-fired turbines and diesel-fired engines to no more than 10 percent opacity for 6-minutes in any one hour to ensure continued compliance with the particulate matter BACT limits. The 10 percent limit has been demonstrated in practice as a reasonable surrogate for demonstrating compliance with particulate matter emissions in existing PSD permits (See Operating Permit No. AQ0181TVP02 and others) for gas-fired emission units. The Department notes that the gas-fired turbines (EUs 1 -10), the ULSD burning EPA Tier 3 diesel engine with an oxidation catalyst requirement (EU 11) and the ULSD burning EPA Tier 4 Final diesel engine all have inherently low opacity.

4.3. EPA Commented – **Combustion Turbine Type.** The proposal indicates that evaluation of more efficient types of combustion turbines were not considered, since ADEC asserts that this would constitute redefining the source. Region 10 suggests that ADEC consider requiring the proponent to evaluate more efficient combustion turbines, for example whether combined cycle turbines could be used in place of the proposed simple cycle turbines, or alternatively, provide an explanation regarding why more efficient turbines are not technically feasible. Use of more efficient turbines would reduce emissions of all pollutants and make use of the high temperature exhaust in producing heat and power for use at the facility.

Department Response: The Department evaluated the information located in the permit application and BACT analysis related to the combustion turbine type and subsequently requested additional information related to NOx and CO emission rates.

The combined cycle power generation combustion turbines are used to generate power at the LNG plant. It is the Department's understanding that the four combined cycle turbines provide sufficient heat for the plant and therefore selecting combined cycle turbines for the compressor turbines is not appropriate since there would be more capacity than necessary and subsequently waste heat that would be unavailable for the three process trains. It should also be noted that AGDC selected the turbine types as appropriate for their proposed operation and requiring them to install combined cycle rather than simple cycle would be considered fundamentally redefining the source. The NOx and CO emission rates have decreased since the

preliminary permit went out for public comment and are now 2 ppmv NOx for both sets of turbines, 2 ppmv CO for the combined cycle turbines, and 5 ppmv for the simple cycle turbines.

4.4. EPA Commented – **Engines DOC and PCV.** In the analysis for the diesel engines, both diesel oxidation catalyst (DOC) and positive crankcase ventilation (PCV) are determined to be technically feasible, but no cost analysis appears to have been conducted. Therefore, the analysis should explain the basis for rejection of these control technologies as BACT.

Department Response: The Department has updated the diesel engine BACT section for particulates to include a more detailed analysis. For EU 11, an oxidation catalyst has been found to be BACT in order to control CO and VOC emissions, which will also offer some level of particulate control. For EU 12, the section has been updated to explain that an oxidation catalyst was found to be cost ineffective and Tier 4 Final engines have inherent designs to control for emissions from the crankcase.[2]

4.5. EPA Commented – **EU 11 DOC.** Given that the analysis for the diesel firewater pump engine determined that DOC is both technically feasible and cost effective, Region 10 does not see a reason for rejecting this control technology under the BACT process. The fact that the unit has hourly limits is irrelevant to the BACT determination, other than as a factor in determining the emission reduction.

Department Response: The Department has modified the BACT finding for EU 11 to require an oxidation catalyst to control CO and VOC emissions.

4.6. EPA Commented – **BACT Emission Limits.** Many of the numeric emission limits proposed in the draft permit are simple arithmetic averages of emission limits from all relevant BACT determinations found in the RBLC in the past ten years. The BACT emission limit should reflect the "best" available control technology, not the average. Region 10 recommends that rigorous technical justification be included on an emission-unit-specific basis to provide the specific reasoning describing why lower emission rates, established as BACT at other similar emission units, are not achievable as BACT for the proposed emission units.

Department Response: Preliminary Construction Permit AQ1539CPT01 relied on averaging of BACT determinations from the RBLC to set CO emission factors for both sets of gas-fired turbines. The Department also notes that the preliminary permit also used the AP-42 emission factor for uncontrolled gas-fired turbines for VOC emissions. The make and model of gas-fired turbines have not been identified

[2] EPA Final Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, May 2004; https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&cad=rja&uact=8&ved=2ahUKEwi33OLwgI34AhXmATQIHfTXB-MQFnoECAgQAQ&url=https%3A%2F%2Fwww.epa.gov%2Fregulations-emissions-vehicles-and-engines%2Fregulations-emissions-heavy-equipment-compression&usg=AOvVaw3JYCv-Y26tPtFQqdZmDLVp and 40 C.F.R. 1039.115(a).

by AGDC. Therefore, the Department needs to set the most conservative emission rates that can actually be achieved for each EU based on the control technology selected.

The Department submitted an information request to AGDC on May 27, 2022, requesting updated CO and VOC BACT emission rates for the turbines. AGDC responded on June 6, 2022, recommending the Department keep the preliminary CO BACT emissions rate of 5 ppmvd at 15% O_2 and selected a new VOC emissions rate of 2 ppmvd @ 15% O_2 for both sets of turbines. The Department concurs that the new proposed VOC emissions rate of 2 ppmvd at 15% O_2 is BACT for both sets of turbines. The RBLC results for simple cycle turbines equipped with oxidation catalysts contains VOC emissions limits ranging from 2 to 3 ppmvd at 15% O_2. The RBLC results for combined cycle turbines equipped with oxidation catalysts contains VOC emissions limits ranging from 0.7 to 5 ppmvd at 15% O_2 with a median and mode of 2 ppmvd at 15% O_2. All the determinations in the RBLC search results for the combined cycle turbines below 2 ppmvd at 15% O_2 were located in the Lower 48 States. The Department intends to set a BACT limit that is achievable by the Permittee and taking into account the harsher and colder environment in Alaska, we did not feel that a VOC limit lower than 2 ppmvd at 15% O_2 would be achievable for the Liquefaction Plant's turbines.

The Department also concurs with the CO BACT emissions limit for the simple cycle turbines EUs 1 through 6 of 5 ppmvd at 15% O_2. The Department chose this limit after examining emission limits in the RBLC for all large simple cycle turbines using oxidation catalysts. This RBLC search returned results ranging from 1.5 ppmvd at 15% O_2 to 10 ppmvd at 15% O_2 with a median and mode of 6 ppmvd at 15% O_2. The case of the 1.5 ppmvd at 15% O_2 determination was for turbines that were also meeting a Least Achievable Control Technology (LAER) limit for VOCs and was located in Maryland. There were two cases of turbines at power generating facilities in Maryland and New York that had CO limits of 2 ppmvd at 15% O_2. However, the simple cycle turbines at the Liquefaction Plant will drive refrigeration compressors and operate over a wider range of operating conditions than the steady-state power generation turbines in the RBLC. Therefore, the Department agrees that slightly higher CO limits are justified given the cyclical nature of the operating conditions and harsher and colder environment in Alaska.

For the combined cycle power generation turbines EUs 7 through 10 the Department has rejected AGDC's recommendation of a CO BACT limit of 5 ppmvd at 15% O_2 and chosen to implement a more stringent limit of 2 ppmvd at 15% O_2. The Department chose this limit after examining emission limits in the RBLC for all large combined cycle turbines using oxidation catalysts. This RBLC search returned results ranging from 0.9 ppmvd at 15% O_2 to 15 ppmvd at 15% O_2, with the majority of the determinations being 2 ppmvd at 15% O_2. All the determinations on the lower end of the RBLC search results were located in the Lower 48 States. The Department intends to set a BACT limit that is achievable by the Permittee and taking into

account the harsher and colder environment in Alaska did not feel that a CO limit lower than 2 ppmvd at 15% O_2 would be achievable for the Liquefaction Plant's combined cycle turbines.

4.7. NPCA Commented – "**BACT Emission Limits for CO.** ADEC Fails to Follow the Regulatory Requirements in Proposing BACT for Carbon Monoxide (CO) for the Natural Gas-fired Compressor Turbines and the Power Turbines. As outlined in Ms. Stamper's Report, AGDC's proposed CO BACT limit at both the compressor turbines and at the power turbines reflects the *least* stringent emission limit that has been required as BACT for CO with oxidation catalyst at gas-fired turbines in the EPA's RACT/BACT/LAER Clearinghouse.[276] While ADEC proposed a lower CO limit, rather than follow the proper BACT methodology and evaluate the lowest CO limit achievable with catalytic oxidation at gas-fired turbines, ADEC simply took the average of the CO emission limits required for this control at gas turbines and proposed a CO BACT emission based on an average for both the compressor turbines and the power turbines.[277] This approach, and the others presented in Ms. Stamper's Report is inconsistent BACT regulation because it is not based on the maximum degree of emission reduction that can be achieved considering the costs of controls and other environmental and energy factors. The goal of the BACT analysis is to be technology forcing and ensure the maximum degree of emission reduction is achieved, and this is best achieved through the top-down BACT review. ADEC must follow the regulatory process and impose a CO BACT limit reflective of the maximum degree of CO emission reduction achievable at the Liquefaction plant compressor turbines and at the power turbines."

Department Response: The Department has reviewed the CO emission limits for the compressor and power turbines and has selected 2 ppmvd for the combined cycle turbines and 5 ppmvd for the single cycle turbines. The Department finds this to represent the maximum level of CO control for these types of emission units at the Liquefaction Plant. See the Department's response to Comment 4.7 for a more detailed rationale for why we chose these limits.

4.8. NPS Commented – "We recommend that the draft permit be revised to include annual emission limitations (in tons per year) for all criteria pollutants."

Department Response: The Department did not revise the permit to include annual emissions limitations in tons per year for all criteria pollutants. The BACT limits already established in the permit are based on concentrations of pollutants in the exhaust (e.g. ppmv), concentrations of sulfur in the fuel (e.g. ppmv and ppmw), and amount of pollutant per energy input (e.g. lb/MMBtu and lb/hp-hr). The Department believes these methods of setting short term emission limits are a more meaningful way of setting BACT pollutant limits compared to annual tpy limits and are adequate in satisfying the requirements contained in 40 C.F.R. 52.21.

4.9. NPCA Commented – "**ADEC's BACT for the Diesel-Fired Engines (EUs 11 and 12) is Unlawful**. The Liquefaction plant will have two diesel-fired engines- a 575 horsepower diesel fire pump (EU 11) and a 300 horsepower diesel-fired auxiliary air compressor engines (EG 12). The Draft Permit limits operations of these engines to 500 hours per year each. These engines are of a source category regulated under the EPA's New Source Performance Standards (NSPS) at 40 C.F.R. Part 60, Subpart IIII (Standards of Performance for Stationary Internal Combustion Engines). Therefore, as discussed in detail earlier in our comments, BACT can be no less stringent than the applicable NSPS standards. As presented in detail in Ms. Stamper's Report, ADEC has proposed BACT limits for these engines that are less stringent than the NSPS BACT floor.

Given that BACT is supposed to be based on the maximum degree of emission reduction achievable and the fact that this is a new Liquefaction plant, ADEC should require that both diesel engines meet Tier 4 emission standards as BACT limits. Tier 4 engines are readily available and, given that Tier 4 engines achieve the lowest emission rates of NOx, PM and CO, such engines should be considered BACT for the firewater pump (EU 12) as well as for the auxiliary air compressor (EU 11)."

Department Response: The Department has not chosen BACT emissions limits for the diesel-fired engines that are higher than those from NSPS Subpart IIII. The Department has instead used the emission limits required under the Subpart which is Table 4 of Subpart IIII for the fire pump engine EU 11 (equivalent to EPA Tier 3) and EPA Tier 4 for the non-emergency auxiliary air compressor EU 12 with the applicable not to exceed standards identified in 40 C.F.R. 1039.101(e). Under 40 C.F.R. 60.4212(b) of Subpart IIII it states, "Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder <u>*who conduct performance tests*</u> *pursuant to this subpart must do so according to paragraphs (a) through* (e) *of this section. Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR Part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e)... [emphasis added]"*

The tiered emissions standards under EPA regulations use values based on a weighted cycle, which is why the not to exceed standards were included with the Subpart for performance tests. To clarify, the Department has included language in both of the BACT sections in the permit and TAR to clarify that the engines must meet the appropriate EPA Tier emission standards.

Regarding the portion of the comment that "ADEC should require that both diesel engines meet Tier 4 emission standards as BACT limits." ADEC has no regulatory basis to require the diesel fire pump engine EU 11 to meet EPA Tier 4 emission standards. BACT is evaluated on an individual pollutant basis for each control method associated with reducing a particular pollutant. ADEC evaluated the top

controls for the diesel engines and have selected an oxidation catalyst to control CO and VOC emissions for the fire pump engine EU 11.

4.10. NPCA Commented – "**ADEC Must Not Exempt Periods of Startup and Shutdown at the Compressor Turbines and the Power Turbines from BACT Emission Limits**.

ADEC has proposed to exempt periods of startup and shutdown from BACT emission limits for the compressor and power turbines. Instead of requiring compliance with BACT emission limits during these time periods, ADEC simply requires that AGDC operate the turbines "according to manufacturer's specifications and good combustion practices." ADEC's proposed work practice standards are vague and provide significant flexibility to AGDC without providing assurance that emissions will be minimized during these periods. In addition, the permit does not require any recordkeeping or reporting on the frequency, magnitude, and duration of exceedances of BACT emission limits during startup, shutdown, or malfunction, nor does the permit require any documentation that manufacturer's specifications and good combustion practices were followed during such periods. ADEC should either not allow any exemptions during periods of startup and shutdown, or ADEC must set alternative BACT emission limits during these periods that reflect BACT for the make and model of turbines that should also be specified in the permit."

Department Response: The Department has revised the permit to include a limit on the amount of time the turbines can operate without the SCR and/or oxidation catalyst pollution control systems in full operation to 40 hours per consecutive 12-month period each, to ensure the maximum level of control during these operations. The new condition language includes requirements for AGDC to monitor, record, and report these hours in each semi-annual operating report. The 40 hours of allotted time for pollution control system bypass are necessary for periods of startup and shutdown when the exhaust stream is not up to the manufacturer's recommended catalyst temperatures. ADEC's use of "good combustion practices" and adherence to operating within manufacturer's specifications ensure that emissions during startup and shutdown will be minimized during these periods. ADEC's annual compliance certification requirements ensure that the permittee adheres to those conditions requiring proper operation of the units during periods of startup or shutdown.

4.11. NPCA Commented – "**The Proposed Permit Lacks BACT Emission Limitations for the Fugitive Emissions**.

Once a facility's potential to emit exceeds the major source threshold, its fugitive emissions—or those that cannot "reasonably pass through a stack, chimney, vent or

other functionally equivalent opening"[3] —are subject to BACT the same as all other emissions. "[A] a major emitting facility is subject to the requirements of section 165 for each pollutant it emits irrespective of the manner in which it is emitted."[4]"

Department Response: The Department did not include BACT limits for fugitive GHG and VOC emissions from the stationary source per 40 CFR 52.21(j)(2) which indicates that:

> *"A new major stationary source shall apply best available control technology for each regulated NSR pollutant that it would have the potential to emit in significant amounts.*

The permit application calculates the potential to emit of fugitive GHG and VOC emissions for miscellaneous LNG affected facilities at 2,671.82 and 17.96 tons per year, respectively. The Department finds that the quantity of these fugitive emissions doesn't constitute significant amounts. The Department notes that the fugitive VOC emissions will be controlled by the technological standards under 40 C.F.R. 60 Subpart OOOOa and 40 C.F.R. 63 Subpart HH for Leak Detection and Repair (LDAR) which will be included in the source's Title V operating permit.

4.12. NPCA Commented – "**ADEC's Consideration of the Use of Electric Compressors and Aeroderivative Turbines Fails to Follow the Regulatory Requirements**."

Department Response: The Department evaluated the information located in the permit application and GHG BACT analyses related to the combustion turbine types and the use of electric compressors and aeroderivative turbines.

The Department notes that the proposed Liquefaction Plant will have a power demand larger than the local utilities can provide. Therefore, electric compressors are not technically feasible for the project and were not included in the BACT determination. It should also be noted that it is the responsibility of the applicant to select the appropriate emissions unit types associated with their project. To that end, AGDC has selected industrial turbines as appropriate for their proposed operation and requiring them to install aeroderivative turbines would be considered fundamentally redefining the source.

Further, AS 46.14(b)(1) prohibits the Department from requiring a (person) "to use machinery, devices, or equipment of a particular type" in permits issued under this chapter. The applicant must thoroughly consider and select the machinery function, make and model that best suits their intended application, as well as construction budget constraints.

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[3] 18 AAC 50.990(40), 40 C.F.R. § 51.166(b)(20). Moreover, the PSD requirements apply to "apply to each regulated pollutant that a "major" source emits in "significant" amounts, e.g., 40 C.F.R. § 52.21(j). The regulations do not distinguish between stack and fugitive emissions for this purpose. *Masonite* at 582, citing 54 Fed. Reg. 48870

[4] *Ala. Power Co. v. Costle*, 636 F.2d 323, 359 (D.C. Cir. 1980)("Alabama Power").

The NOx and CO emission rates have decreased since the preliminary permit went out for public comment and are now 2 ppmv NOx for both sets of turbines, 2 ppmv CO for the combined cycle turbines, and 5 ppmv for the simple cycle turbines. The Department also included limits on startup and shutdown times to ensure that BACT limits and operational practices are achieved at all times.

4.13. NPCA Commented – "**ADEC Has Not Justified that the GHG Limit it Proposes is BACT**.

Contrary to the requirements in Alaska's SIP, ADEC fails to evaluate and document GHG BACT for the compressor turbine and the power turbines. For example, ADEC fails to provide a technical basis for its proposed GHG BACT limit for the compressor turbines and power turbines, it merely suggests the limit is based on good combustion practices and burning clean fuels.[5] Furthermore, in setting this limit, ADEC cannot rely on AGDC's information for the CO_2 emissions rate per megawatt-hour for its compressor turbines, because AGDC did not provide nor does the permit specify the turbine make or model.[6] As Ms. Stamper identifies in her report, "A review of the draft permit shows that ADEC has imposed the same 117.1 lb/MMBtu GHG BACT limit for every emission unit at the proposed Liquefaction plant – that is, the compressor turbines, the combined cycle emission units, and the flares."[7] These are not case-specific BACT determinations, rather ADEC's proposed limits are "simply the EPA GHG emission factor for natural gas combustion at any type of combustion source."[8] Contrary to the requirements, ADEC's limit does not:

• Reflect the maximum degree of GHG emission reduction achievable for the source considering costs of control and other impacts; and

• Encourage improvements in efficiency or even good combustion practices."

Department Response: The Department has left the emission factors for the turbines intact as they are the most representative emission factors available at this time. The Department notes that AGDC is still in the planning phase of the project and does not have specific manufacturers identified for the turbines. Therefore, the EPA's GHG emission factor for natural gas combustion is the most representative for GHG emissions from the turbines. The comment states that the GHG emission factor "does not reflect the maximum degree of GHG emission reduction achievable for the

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[5] Stamper Report at 28-29. Additionally, as Ms. Stamper explains, AGDC's submittal similarly lacks the required BACT evaluation as AGDC did not identify any claimed heat rate for those turbines and simply proposed using a combined cycle turbine, low carbon fuel, and energy efficiency as BACT for GHG emissions. Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 44.
[6] Id.
[7] Stamper Report at 29.
[8] Id. *See* EPA GHG Emission Factors, available at https://www.epa.gov/sites/production/files/2020-04/documents/ghg-emission-factors-hub.pdf. The emission factors for CO2, methane (CH4) and nitrous oxide (N2O) convert to 117.1 lb/MMBtu (after applying the global warming potential factors in 40 C.F.R. Part 98, Table A-1.

source considering costs of control and other impacts." However, the Department notes that the BACT process was properly followed and most effective control that is technologically feasible has been selected as BACT.

5. Flaring

5.1. NPCA Commented – "Alaska's BACT analysis for flaring is also deficient, because ADEC failed to consider capture and use requirements (in lieu of flaring the excess natural gas) or the use of a thermal incinerator instead of flaring (which results in better control of volatile organic compounds (VOCs) and NOx. Moreover, ADEC's proposed permit terms for its flaring BACT control of "minimization of flaring" are not adequate to ensure flaring is indeed minimized. ADEC has proposed to limit flaring during equipment startup, shutdown, and maintenance to 500 hours per year per flare, but is not limiting flaring due to plant upsets (likely the major cause of flaring) at all."

"While ADEC conducted a BACT analysis for the various pollutants to be emitted by the flares, the emission limits it has proposed are, with the exception of SO_2, simply reflective of EPA emission factors for flare.[9] The Draft Permit also imposes a GHG emission limit of 117.1 lb/MMBtu[10] which, as stated above, is simply the same as the EPA GHG emission factor for GHG emissions from natural gas combustion (i.e., it does not require any reduction in GHG emissions). Further, although ADEC has proposed emission limits in terms of lb/MMBtu for NOx, CO, PM, VOCs, and GHG, there are no requirements to ensure that these emission limits are met, other than training of flare operators and meeting the work practice standards of 40 C.F.R. §§ 60.18(c) through (f).[11]"

Department Response: The Department has updated the flaring BACT control descriptions in Section 7 in the TAR to include a write-up on both flare gas recovery and thermal oxidation/incineration, as well as an explanation on why these technologies are considered technologically infeasible for the Liquefaction Plant. Additionally, The Department has included a Flare Minimization Plan in Section 11 of the permit that will ensure that AGDC minimizes emissions from the flare. As suggested in the comment, this plan requires AGDC to conduct a root cause analysis and a corrective action analysis for any unplanned flaring event that results in a combustion of 500,000 standard cubic feet dry or more of gas in any 24-hour period. The Flare Minimization Plan also requires records be kept for five years and that corrective action be taken to minimize future unplanned flaring events. However, the flare is used as an emergency control device to ensure that large quantities of gaseous fuel are not vented directly to the atmosphere during plant upsets and for that reason, the Department is not placing a limit on the amount of time that this

[9] ADEC's Preliminary September 11, 2020 TAR, Appendix B at 64, 66, 67, 71, and 73. Stamper Report at 34.
[10] Draft Permit at 23 (Condition 17).
[11] Id. at 24.

flaring can occur to ensure that uncontrolled venting of emissions to the atmosphere is avoided.

The Department has left the emission factors for the flare intact as they are the most representative emission factors available at this time. The Department notes that AGDC is still in the planning phase of the project and does not have specific manufacturers identified for the flares. Therefore, EPA's AP-42 emission factors are the most representative for NOx, CO, PM, and VOCs from the flares and the EPA's GHG emission factor for natural gas combustion is the most representative for GHG emissions from the flares. The comment states that the GHG emission factor "does not require any reduction in GHG emissions." However, the Department notes that the BACT process was properly followed and most effective control that is technologically feasible has been selected as BACT.

Regarding the portion of the comment that states, "there are no requirements to ensure that these emission limits are met, other than training of flare operators..." The Department notes that source testing for flares is impracticable due the inherent nature of an external flare and therefore, no source testing for BACT emission limits is reasonable.

5.2. Chickaloon Commented – We object to flaring, currently allowed in the permit under Section 6.3, and the consequent release of methane into the atmosphere. As a potent greenhouse gas, this activity can be indirectly linked to the warming observed in streams in our area, the health impacts caused by increasing wildfires, and other impacts that affect us.

- It appears that seven units will be allowed to emit 117 lb per MMBtu per year during flaring, along with another "thermal oxidizer" allowed to emit the same amount (Tables 6 and 8) for over 900 lbs of greenhouse gases permitted each year for each MMBtu.
- Dry ground flares at 3 units, if flared at maximum, make up 61% of the total greenhouse gases from this plant. What options are there to eliminate flaring?

Department Response: The Department has included a Flare Minimization Plan in Section 11 of the permit to ensure that AGDC minimizes emissions from the flare. This plan requires AGDC to conduct a root cause analysis and a corrective action analysis for any flaring event that results in a combustion of 500,000 standard cubic feet dry or more of gas in any 24-hour period.

The Department analyzed if there were any technically feasible controls for the vent gas other than flaring. During this analysis it was determined that flares were the only feasible control due to the nature of the vent gas as a non-continuous gas stream with large quantities needing to be controlled as a possible result of plant upsets. Economics was not a factor in this analysis.

5.3. AGDC commented on an issue discovered by the NPS regarding an error in the potential to emit calculation for the flares. AGDC's comment is below in its entirety:

In addition, you had asked for more information on the fact that the potential to emit (PTE) estimate for flares at the liquefaction facility used emissions from four flares at 500 hours/flare when there are actually six total flares (three wet and three dry) planned on site. We confirmed the project design indicates that two (one wet and one dry) of the six total flares are spares and will not regularly operate. The spares will be brought on line when the operational flares are taken off line for maintenance. [Reference: Attachment 5, Appendix D to Alaska LNG Resource Report 9 (Liquefaction Facility Air Quality Modeling Report), Sections 4.1.1.1 and 4.1.2.4] Therefore, to be consistent with the design basis of the facility, AGDC suggests a flaring limit based on total throughput that would be the equivalent of four flares at 500 hours/flare (excluding pilot and purge, emergency, or process upset flaring). We also suggest Table 12 -Detailed Permanent EU Inventory and Potential to Emit (tpy) in the TAR Appendix A Emissions Calculation be revised to clarify that total emission with maximum flaring only includes emissions from 2 Dry Ground Flares and 2 Wet Ground Flares per facility design and operating constraints.

Department Response: The Department has corrected the BACT flaring limits contained in Construction Permit AQ1539CPT01 Table's 7 and 8 and Condition 17.2 to match the flaring operating scenarios described in the comment and the existing potential to emit calculations. Condition 17.2 now reads:

During startup, shutdown, and maintenance events, limit the number of hours flared in any 12 consecutive months to no more than: 1,000 hours combined for EUs 14, 16, and 18, 1,000 hours combined for EUs 15, 17, and 19, and 144 hours for EU 20.[8,9]

[8] *The 1,000-hour combined flaring limits do not include pilot and purge, emergency, or process upset flaring.*

[9] *The 144-hour flaring limit does not include pilot and purge, emergency, or process upset flaring*

5.4. NPS Commented – We recommend that any best practices identified in the "flaring minimization plan" (which is to be completed prior to operation) are made enforceable by ADEC through the permit conditions and that the state consider short-term operational limits for the flares."

Department Response: The Department has included a Flare Minimization Plan in Section 11 of the permit that will ensure that AGDC minimizes emissions from the flare. However, the flare is used as an emergency control safety device to ensure that large quantities of gaseous fuel do not cause over-pressure releases and are not vented directly to the atmosphere during plant upsets and for that reason the Department is not placing short-term limits on the flares.

6. Comments on the Air Quality Modeling Analysis

The Department received comments on the following aspects of AGDC's modeling analysis.

6.1. EPA commented on the TAR, Appendix D, Section 7 (Class I impact analysis and FLM recommendation disclosure). The EPA recommends additional information be provided in the section of the TAR summarizing the input and recommendations of the Federal Land Managers, related to Class I area impact analysis. The additional disclosure would help demonstrate the fulfillment of the requirements under 40 CFR 52.21(p), adopted by reference in 18 AAC 50.

Section 2.2 of TAR Appendix D indicates the FLMs were involved in the AQRV analysis process of the permit, but no references to supporting documentation and recommendations were evident in the TAR. Additional disclosure is especially important given a cumulative AQRV impacts analysis was necessary. The cumulative analysis efforts would necessitate coordination with the FLMs to identify appropriate cumulative thresholds (such as the critical loading factors used in the analysis) and modeling methodologies. [comment paraphrased]

Department Response: Section 2.2 of the Department's Modeling Report provides a summary of the ambient demonstration requirements for PSD applicants under 40 C.F.R. 52.21. The Department limited its discussion in this section to a summary of requirements and salient aspects of the applicant's approach for clarity. The Department, however, recognizes the case-specific merit of the Commenter's recommendation. It is, therefore, revising this section of its Modeling Report to include a footnote acknowledging FLM interest in the characterization of impacts within expanded areas of concern. The new footnote will also acknowledge AGDC's analytical efforts, summarized in Section 7 of the Department's Modeling Report, to identify impacts of greater scope than the ambient demonstration requirements for PSD applicants.

The Department discussed the satisfaction of the notification requirements under 40 C.F.R. 52.21(p) in Section 2.2 of its Modeling Report. It relied upon FLM guidance and criteria[12] to inform the notification process. Citations of the relevant FLM notifications are included by footnote reference.

6.2. NPS commented on the modeled nitrogen deposition effects the proposed source would have on lichens in the Denali National Park (NP) Class I area. The Federal Land Managers' Air Quality Related Values Work Group (FLAG) 2010 guidance defines the Deposition Analysis Thresholds (DATs) as "… the additional amount of nitrogen or sulfur deposition within an FLM area, below which estimated impacts from a proposed new or modified source are considered negligible. In other words, if the new or modified source has a predicted nitrogen or sulfur deposition impact

[12] Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase 1 Report – Revised (2010).

below the respective DAT, the NPS and FWS will consider that impact to be negligible, and no further analysis would be required for that pollutant. In cases where a source's impact equals or exceeds the DAT, the NPS/FWS will make a project-specific assessment of whether the projected increase in deposition would likely result in an "adverse impact" on resources considering existing AQRV conditions, the magnitude of the expected increase, and other factors."

NPS referenced a model developed for total nitrogen (N) deposition that estimated 2013 levels of 0.5 to 2.1 kg-N/ha/yr (median 0.8 kg-N/ha/yr), with the highest deposition occurring in the southern regions of the park. NPS referenced a study that found that there are 431 known lichen species in Denali NP. The median critical load value (threshold for deposition levels below which result in harmful impacts to the ecosystem, ecosystem components, or individual species do not occur) for these lichen species which were identified is a 20% decline at 1.3 kg-N/ha/yr and a 30% decline at 1.9 kg-N/ha/yr. NPS also noted that of particular concern is the globally rare boreal felt lichen (*Erioderma pedicellatum*), which has only recently been discovered in the U.S. at sites within Denali NP, and is listed as a critically endangered species by the Union for Conservation of Nature.

NPS in collaboration with U.S. Fish and Wildlife Services re-ran the modeling analysis with four emission scenarios. These include the Liquefaction Facility with normal operations and max potential to emit (PTE), as well as the Liquefaction Facility combined with pipeline compressor stations with normal operations and max PTE (see table below). The NPS notes that the PTE for the Liquefaction Facility includes flaring at 500 hours a year for each of the wet and dry flares and 144 hours per year for the low pressure flare, which results in 5,040 tpy of NOx. NPS notes that they included the additional pipeline compressor stations in the modeling analysis under the additional impacts analysis provisions of 40 C.F.R. 52.21(o). NPS again notes that the highest levels of nitrogen deposition will occur in the southern end of Denali NP as can be seen from the following modeled deposition maps.

[IMAGES TRUNCATED]

NPS makes the following recommendation regarding the impacts of nitrogen deposition on Denali NP, "We recommend that ADEC reconsider the nitrogen oxide (NOx) Best Available Control Technology (BACT) determination for the ten combustion turbines located at the facility and implement Selective Catalytic Reduction (SCR) technology to reduce potential nitrogen deposition impacts in Denali NP. SCR is a commonly applied and cost-effective control technology for turbines and can reduce flue gas NOx concentrations to as low as 2.0 ppmvd. Requiring SCR at a 2.0 ppmvd NOx limit would ensure a level of NOx control at the liquefaction facility that is requisite with other similar sources in Alaska and elsewhere in the lower 48 states…" [comment paraphrased]

Department Response: AGDC has since amended their application to rely upon SCR for their proposed fuel gas-fired turbines; see the response to Comment 2.1.

Offsite Emissions Inventory on Class I Increment Analysis

6.3. EPA commented on the TAR, Appendix D, Section 10.2 (Offsite emissions inventory for Class I increment analysis). The emissions from the Alaska LNG pipeline compressor and heater stations could be classified as secondary emissions (as defined in 40 CFR 52.21(b)(18)) because the emissions from these offsite facilities would occur as a result of the construction and operation of the Liquefaction Facility. Secondary emissions should be explicitly modeled in the source impact analysis (refer to 40 CFR 52.21(k)) if these emissions are specific, well-defined, quantifiable, and impact the same general area as the stationary source undergoing review (refer to 1990 Draft New Source Review Workshop Manual). The secondary emissions from these offsite sources were excluded from the modeling, primarily because they would not impact the same general area as the project source.

However, the emissions from the Honolulu Creek Compressor Station (HCCS) may be of particular concern because the proposed location of the HCCS is on the path of the plume from the project source to the Class I Denali National Park and Preserve (DNPP) and is relatively near to the boundaries of DNPP (14 km). It is not clear if the emissions from the HCCS could impact the same general area of concern as the project source, which in this case would be the Class I Significant Impact Area (SIA) portion of DNPP (the Class I SIA would be the portion of Class I modeled receptors with project-emission impacts greater than the Class I Significant Impact Levels).

It would be useful to identify the Class I SIA of Denali National Park (DNPP) to understand what portions of DNPP could be impacted by the project. If the SIA contains receptors in the vicinity of the HCCS, then additional review is warranted to determine if project impacts could cause or contribute to the violation of a Class I PSD increment, when HCCS impacts are accounted for. Namely, the PM2.5 24-hour increment would be of concern, given the modeled maximum cumulative impact of 1.76 µg/m3 vs. the increment of 2.0 µg/m3 and given the HCCS NOx emissions of 131.2 tpy which would contribute to PM2.5 impacts through secondary pollutant formation. [comment paraphrased]

Department Response: The Department understands the Commenter has advanced an informed position recommending the consideration of potential emissions from AGDC's proposed Honolulu Creek Compressor Station. They indicate the emissions from the proposed mid-stream facility may be considered 'secondary' in accordance with the definition under 40 C.F.R. 52.21(b)(18).

The Department notes that it found AGDC's proposed mid-stream sources are not aggregated with the Liquefaction Plant stationary source for the purposes of PSD review; see the Department's response to Comment 12.1. Impacts from AGDC's

mid-stream sources will be considered in accordance with the regulatory requirements appropriate for their respective permit classification(s). A discussion of AGDC's secondary emissions is provided in Section 5.6.3 of the Department's Modeling Report.

6.4. NPS commented on the "Additional Impacts Analysis" required under 40 CFR 52.21(o)(2), noting that the applicant concludes *"No industrial or commercial growth is likely to occur as the requirements for the project are expected to fit within the current infrastructure in the area."* NPS notes that there are several proposed compressor and/or heater stations to be located along the pipeline delivering natural gas to the liquefaction facility, three of which are in proximity to Denali NP. NPS states, "This source growth is clearly connected with the liquefaction facility, as it is part of the overall AK LNG project, and therefore, it is relevant to the Class I impacts analysis. For this reason, our revised modeling analysis also considered the compressor and heater stations and we recommend that AGDC's analysis should as well."

Additionally, the NPS notes that vegetation impacts analysis required under 40 CFR 52.21(o)(1) concluded: "*Therefore, a project that demonstrates compliance with the NAAQS easily demonstrates compliance with USEPA's threshold screening values and indicates the project will not cause deleterious effects to vegetation.*" NPS went on to note that the analysis acknowledged that "*lichen species are particularly sensitive to sulfur dioxide (SO2)*" and utilized a 1989 U.S. Forest Service document to consider impacts to lichens in the Tongass National Forest and concluded the "*ambient air quality impacts are overstated and they are still not expected to result in adverse growth effects or tissue injury to vegetation in the project area.*" NPS states that, "based on the information provided above, AGDC's information is outdated, does not consider the potential deleterious effects of nitrogen deposition on lichens, and inaccurately concludes that the NAAQS are protective of sensitive vegetation species. As we note above, lichens in Denali NP may be negatively impacted by nitrogen deposition and the AK LNG project may exacerbate these concerns." [comment paraphrased]

Department Response: The Commenter performed an evaluation of nitrogen deposition within the Denali National Park Class I area. Their evaluation includes the estimated project impacts from various AGDC-proposed operations. They indicate adverse impacts to lichen may occur based on the results of this evaluation.

The Department understands that the Commenter employs deposition analysis thresholds (DATs), below which federal land manager guidance[13] indicates impacts may be considered negligible. Their evaluation assumes an annual range of pre-

[13] Federal Land Managers' Interagency Guidance for Nitrogen and Sulfur Deposition Analyses. Natural Resource Report NPS/NRSS/ARD/NRR-2011/465; November, 2011.

existing nitrogen deposition impacts[14] within Denali in 2013, from which estimated project impacts are superimposed for comparison to the DATs. The Commenter's assumed pre-existing impacts appear to approach the DATs and are approximately two orders of magnitude greater than those attributable to AGDC's estimated operations. It is, therefore, questionable whether an appropriate case-specific analytical framework may be developed using the Commenter's national model-generated impacts from 2013.

The Commenter observed estimated impacts from AGDC's proposed mid-stream facilities in their evaluation of nitrogen deposition within Denali. They recommend AGDC include impacts from their proposed mid-stream facilities in the ambient demonstration for the Liquefaction Plant. The Department found AGDC's proposed mid-stream sources are not aggregated with the Liquefaction Plant stationary source for the purposes of PSD review; see the Department's response to Comment 12.1 for detail. Impacts from AGDC's mid-stream sources will be considered in accordance with the regulatory requirements appropriate for their respective permit classification(s).

The Department notes that AGDC has since amended their application to rely upon SCR for their proposed fuel gas-fired turbines; see the response to Comment 2.1. The use of SCR will mitigate the potential for nitrogen deposition from the source. The Department is, therefore, maintaining its findings regarding AGDC's fulfillment of the requirements under 40 C.F.R. 52.21(o).

NPCA Comments on AGDC's Ambient Demonstration

NPCA provided broad commentary on the Department's preliminary decision to approve PSD permit AQ1539CPT01. A portion of these comments are germane to AGDC's ambient demonstration and rely upon the reported findings of a third-party.[15] The Department is expanding its response to the NPCA's comments and has paraphrased their underlying language in the interests of clarity. NPCA's original, unabridged comments on AGDC's ambient demonstration are included on pages 59 through 85 of their December 10, 2020 e-mail submission[16].

6.5. (NPCA) The draft permit unlawfully relies upon deficient and inaccurate air quality modeling. [comment paraphrased]

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[14] Hember, R. A. (2018). Spatially and temporally continuous estimates of annual total nitrogen deposition over North America, 1860-2013. *Data in Brief*. 17:134-140.
[15] D. H. Gebhart. (6 December, 2020). *Technical Comments on Alaska LNG Project – Liquefaction Plant PSD Permit*. Air Resource Specialists, Inc.: Fort Collins, CO.
[16] E-mail from Sara L. Laumann, Laumann Legal, LLC, to Dave Jones, ADEC: *Re: National Parks Conservation Association, Center for Biological Diversity, and Northern Alaska Environmental Center Comments on Preliminary Prevention of Significant Deterioration Permit No. AQ1539CPT01, Proposed in response to Application from Alaska Gasline Development Corporation to Construct a Liquefaction Plant in Nikiski, Alaska*

Department Response: AGDC's application to construct the Liquefaction Plant stationary source was prepared in observance of the requirements for PSD permits. These requirements include case-specific evaluations of ambient air quality under 40 C.F.R. 52.21. The Department reviewed AGDC's ambient demonstration in consideration of the applicable PSD requirements, relevant guidance, and additional information as it was made available. This review was performed in comport with the authority under 18 AAC 50 and AS 46.14. The Department found that AGDC's ambient demonstration satisfied the requirements for PSD permits. Detail regarding the appropriateness of AGDC's approach to meet discrete regulatory requirements is provided in the Department's Modeling Report.

The Department understands the Commenter questions the reliability and certainty of AGDC's modeling techniques or the rigor with which its staff evaluated these techniques. The Department is, nevertheless, unable to identify specific elements of AGDC's demonstration that are unlawful, deficient, or inaccurate.

6.6. (NPCA) ADEC inappropriately relies on the modeling analysis prepared for NEPA compliance. The comment asserts that AGDC's reliance on elements of their NEPA analyses are inappropriate for use in their PSD application; this led to substantial and significant errors; AGDC's ambient demonstration is incomplete, inaccurate, and does not provide a complete understanding of ambient impacts; and the Department's review of this information was unreasonable where it did not comply with the requirements of the Clean Air Act. [comment paraphrased]

Department Response: AGDC's application to construct the Liquefaction Plant stationary source was prepared in observance of the requirements for PSD permits. These requirements include case-specific evaluations of ambient air quality under 40 C.F.R. 52.21. The Department reviewed AGDC's ambient demonstration in consideration of the applicable PSD requirements, relevant guidance, and additional information as it was made available. This review was performed in comport with the authority under 18 AAC 50 and AS 46.14. The Department found that AGDC's ambient demonstration satisfied the requirements for PSD permits. Detail on the appropriateness of AGDC's approach to meet discrete regulatory requirements is provided in the Department's Modeling Report. Detail on the assumptions of their 'normal operations' modeled scenario is provided in AGDC's application materials.

The Department notes that AGDC relied, to the extent possible, upon analyses prepared in support of NEPA to meet the PSD requirements of 40 C.F.R 52.21. EPA encourages this type of coordinated approach as described under 40 C.F.R. 52.21(s). This citation has not been adopted in Alaska's administrative code. The Department, nevertheless, has the authority to consider various consistent approaches that may be reasonable and feasible.

6.7. (NPCA) ADEC failed to consider the range of operations in the modeling scenarios. The comment asserts that it is unreasonable for the Department not to consider

different flaring operations; AGDC's ambient demonstration is incomplete because of this; AGDC's model-assumed operation of the turbines is unrealistic; and the Department should impose enforceable permit terms and conditions prohibiting the operation of these units below 100-percent load. [comment paraphrased]

Department Response: AGDC considered multiple operational scenarios. These scenarios are described under Section 4.1 of their application. The Department finds AGDC's 'normal operations' modeled scenario offers a conservative characterization of anticipated impacts from the proposed stationary source. A factual basis supporting this general characterization may be framed by the relative number, type, and contemporaneous operation of modeled emissions-generating equipment and processes.

Emergency flaring during normal operations will be limited to exceptional events, e.g. during malfunctions, process upsets, and relief conditions. AGDC's 'normal operations' modeled scenario conservatively assumes 500 hours of emergency flaring annually. This modeled scenario also accounts for the steady-state emissions from pilot and purge use. The Department considered the typical operation of similar units, temporal and spatial characteristics of maximum impacts, and potential impacts under other operational scenarios. It found that AGDC's characterization of flaring under the 'normal operations' modeled scenario is appropriate to identify maximum impacts. The Department notes that it included an enforceable flare minimization plan in Section 11 of the final permit; see the response to Condition 5.1.

AGDC developed the modeled emission rates for their turbine EUs assuming 100-percent loading. They characterized the release parameters for these units using emissions-maximizing assumptions, e.g. contemporaneous operation and 'worst-case' temperature regimes. The Department evaluated AGDC's approach and found their characterization under the 'normal operations' modeled scenario is appropriate. The Department, therefore, is not revising the draft permit to include the enforceable terms and conditions requested by the Commenter.

The Department notes that AGDC has since amended their application to rely upon SCR for their proposed fuel gas-fired turbines; see the response to Comment 2.1. The use of SCR will generally diminish the impact potential for the pollutants of concern emitted by these units.

6.8. (NPCA) ADEC ignores onsite meteorological data, fails to demonstrate data used is representative and processes data inconsistently with regulatory requirements. The comment asserts that AGDC used five years of meteorological data collected at the Kenai airport rather than the year collected in the project area of Nikiski; the Department is silent on the representativeness of these data; and AGDC's pre-

processing randomization of wind direction within the Kenai data is inconsistent with EPA guidance. [comment paraphrased]

Department Response: AGDC proposed the use of representative meteorological data from the Kenai airport for their ambient analyses. Five years of data were collected by the National Weather Service at this station from 2008 through 2012. The Department questioned the appropriateness of AGDC's proposed use of these data during pre-application discussions. It noted the anticipated release heights of project point sources would be significantly taller than the height of anemometer instrumentation at the Kenai monitoring station. AGDC subsequently collected a year of 'tall tower' data from the Nikiski area that included wind speed information at 10, 30, and 60 meter heights. They used these 'tall tower' data to research the case-specific sensitivity of meteorological inputs upon model-estimated impacts. AGDC subsequently used the findings of the 'tall tower' effort to support their proposed use of the Kenai data. The Department reviewed AGDC's proposed use of these data and found that they are representative of transport and dispersion within the modeled domain. Detail on AGDC's meteorological approach and the Department's associated findings begin at Section 5.3 within its Modeling Report.

AGDC used hourly averaged wind directions from AERMINUTE and instructed the AERMET preprocessor to randomize wind direction by ±5° when they processed the Kenai airport meteorological data. The randomization is an established practice for hourly NWS data, which are reported to the nearest 10°. Subsequent EPA guidance[17] clarified that the use of hourly averaged wind directions from AERMINUTE eliminates the need to randomize hourly NWS data. Section 3.1 of the cited EPA guidance indicates that "...randomizing the standard NWS wind direction observations was necessary to avoid the potential for overstating the wind persistence based on the original observations which could lead to overly conservative modeled impacts". The use of average hourly wind directions, rather than randomization, is intended to address the lack of precision in NWS data, but in a way EPA suggests will offer "...more appropriate inputs for dispersion modeling". The Department understands that AGDC's approach may lead to overly conservative impacts. It, nevertheless, performed two sensitivity analyses to evaluate the case specific impact of randomized wind direction. The Department found no meaningful differences to model estimated impacts; see Section 5.3.2 of its Modeling Report.

6.9. (NPCA) ADEC relies on baseline air quality data that is not representative of baseline conditions. The comment asserts that AGDC used both site-specific and off-site ambient data to meet the PSD requirements under 40 C.F.R. 52.21(m); the off-site data cannot be used to support a new PSD permit because it is out of date and no longer representative of baseline air quality conditions in the project area; and

[17] Memorandum from Tyler Fox, U.S. EPA Office of Air Quality Standards and Planning, to Regional Modeling Contacts: *Use of ASOS meteorological data in AERMOD dispersion modeling,* 8 March, 2013.

AGDC has not complied with the PSD requirements under 40 C.F.R. 52.21(m). [comment paraphrased]

Department Response: AGDC used both site-specific and off-site ambient data to satisfy the PSD requirements under 40 C.F.R. 52.21(m). They collected a year of site-specific NO_2, SO_2, and CO data during 2018 and 2019 in support of the former. They separately assumed a year of off-site PM-10, PM-2.5, and O_3 data collected in Nikiski to be representative of ambient impacts in the proposed project area. The off-site data were collected by a nearby PSD applicant between 2013 and 2014. Both ambient data sets were previously reviewed and found to be PSD quality.

The Department reviewed AGDC's approach to meet the PSD requirements for pre-construction monitoring. It observed EPA's recommendations in the Guideline and considered data 'freshness' during this review. The Department found AGDC's use of the off-site data appropriate[18] and that their approach satisfied the requirements under 40 C.F.R. 52.21(m). See Section 4 of the Department's Modeling Report.

6.10. (NPCA) ADEC's methodology is inconsistent with the regulatory requirements for NOx emissions modeling. The comment asserts that AGDC used the Ambient Ratio Method 2 (ARM2) to estimate their ambient NO2 impacts; the 2017 Guideline recommends a minimum ambient NO_2/NOx ratio of 0.5; and AGDC used a ratio of 0.2. [comment paraphrased]

Department Response: ARM2 is considered an alternative technique under the 2005 version of EPA's Guideline. Its use requires case-specific approval in accordance with 18 AAC 50.215(c). AGDC received EPA Region 10 approval to use ARM2 on 12 December, 2017. A discussion on AGDC's development of an assumed minimum ambient ratio is provided in Section 5.10.1.2 of the Department's modeling report; a case-specific finding of appropriateness is also provided in this section.

The Department notes that AGDC observed the recommendations of EPA's 2005 version of the Guideline when they prepared their PSD Modeling Protocol. This version was the most current adopted by reference in in 18 AAC 040(f) at the time they submitted their protocol for review. EPA subsequently revised the Guideline but provided a one-year transition period for applicants with modeling protocols based on the 2005 version. EPA stated that such protocols submit in a timely manner may be discretionarily approved by the reviewing authority. The Department approved AGDC's PSD Modeling Protocol on January 17, 2018; see Section 2.4.3 of the Department's Modeling Report.

6.11. (NPCA) ADEC underestimates maritime emissions and fails to include them in the increment analysis. The comment asserts that AGDC only considered maritime emissions within 500 meters of the marine terminal loading dock; impacts are underestimated because the maximum number of vessels serving the source were not

[18] E-mail from ADEC to applicant: ADEC Response Re Nikiski Pre-Construction Monitoring; 13 June, 2017.

modeled; an impact analysis of regional maritime emissions upon the Tuxedni National Wildlife Refuge Class I area was not performed; and impacts at this Class I area are underestimated because maritime emissions were not properly considered. [comment paraphrased]

Department Response: AGDC accounted for ambient impacts from the proposed Marine Terminal in their ambient demonstration. The potential impacts from vessels serving the source were evaluated beyond 500 meters and within the Tuxedni National Wildlife Refuge Class I area. AGDC's approach to estimate marine emissions, including the modeled release parameters, is described in Section 4.1.1.2 of their application. The Department found that AGDC's approach to estimating ambient impacts from the proposed Marine Terminal was appropriate. Discussions and findings regarding this subject are provided throughout the Department's Modeling Report.

The Department notes that AGDC only considered the emissions from marine vessels serving the stationary source during maneuvering, loading, hoteling, cool-down, and purge. Mobile emissions are not considered secondary emissions in accordance with 40 C.F.R. 52.21(b)(18).

6.12. (NPCA) Flaring emission must represent permitted not "average" emission. The comment asserts that AGDC's evaluation of short-term ambient impacts from the proposed flares relied upon annually averaged emission rates, and this approach underestimates potential short-term impacts. [comment paraphrased]

Department Response: AGDC evaluated impacts from the proposed flares in their ambient demonstration. They developed modeled emission rates that were based on engineered designs and 500 hours of annual emergency use. These emission rates contemporaneously accounted for the continuous emissions from pilot and purge operation. A discussion of AGDC's assumed flare release parameters is provided in Section 8.0 of Appendix A to their PSD application.

Emergency flaring at the Liquefaction Plant stationary source is an unscheduled, episodic activity. It occurs during periods of malfunction, process upset, pressure relief, et. al. AGDC, therefore, assumed a maximum potential of 30 minutes of daily flaring in conjunction with 500 hours of annual emergency use. They used annually averaged emission rates in their demonstration of the probabilistic short-term standards. They observed the assumed daily emergency use in estimating the deterministic short-term impacts. The Department finds that AGDC's 500 hours of assumed annual emergency flaring is conservative and that the assumed short-term emergency use is sufficient to characterize their maximum ambient impacts.

The Department separately evaluated AGDC's assumed flaring impacts in its review of their PSD application for the Gas Treatment Plant stationary source. The flaring assumptions in this application are representative of those used for the Liquefaction

Plant and support the findings in Section 5.7.3 of the Department's Modeling Report. Source group results of the Department's evaluation indicate that the impacts from flaring are both spatially distinct from the location(s) of maximum project impacts and smaller in relative scale. A relevant technical discussion is provided in the Department's Modeling Report for Air Quality Control Construction Permit AQ1524CPT01.

The Department notes that it included an enforceable flare minimization plan under Section 11 of the proposed permit; see the response to Comment 5.1 for detail. This plan requires AGDC to perform root-cause and corrective action analyses if greater than 500,000 standard cubic feet of gas is flared in any 24-hour period.

6.13. (NPCA) ADEC applied a model that required but did not receive EPA approval. The comment asserts that AGDC used the Shoreline Dispersion Model (SDM) as an element of their ambient demonstration; the SDM required but did not receive EPA approval as an alternative model under the Guideline; and the PSD permit cannot be issued because of the former. [comment paraphrased]

Department Response: Section 7.2.8 of the Guideline describes complex wind scenarios that an applicant should consider in an ambient analysis. Shoreline fumigation is among these scenarios. AGDC used the SDM to evaluate potential impacts of fumigation driven by tall and/or buoyant exhaust releases at the Liquefaction Plant stationary source. Their use of this model generally entails the conservative superposition of fumigation impacts within the greater AERMOD analyses. The Department, therefore, considers AGDC's use of the SDM a supplement to their use of EPA's preferred model, AERMOD, rather than its replacement as an alternative model. It discussed AGDC's proposed use of the SDM with EPA Region 10 during internal deliberative review. EPA subsequently provided a discussion and tacit approval for AGDC's case-specific use of the SDM in a December 2017 e-mail.[19] AGDC's use of the SDM does not provide a regulatory basis to deny AGDC's PSD permit.

6.14. (NPCA) ADEC failed to consider secondary PM impacts. The comment asserts that AGDC did not address the impacts from secondary particulate matter formation in their ambient demonstration; the estimated maximum increment impacts show no margin of compliance with their respective Class II thresholds; AGDC's demonstration failed to consider associated impacts from the Marine Terminal; AGDC should have considered EPA's draft guidance regarding modeled emission rates for precursors (MERPs); and they should have accounted for the precursor emissions from a proposed nearby source in evaluating their secondary formation impacts. [comment paraphrased]

[19] E-mail from Jay McAlpine (EPA R10) to Alan Schuler (Department) and George Bridgers (EPA), *RE: Quick update on our status for Alaska LNG*; 6 December, 2017.

Department Response: AGDC accounted for the impacts from secondarily formed particulate matter in their ambient demonstration. Their approach to characterize these impacts relied upon ambient data, post-processing, and qualitative discussion. Detail regarding AGDC's approach is provided in Section 5.10.2 of the Department's Modeling Report.

AGDC and the Department considered draft guidance[20] from EPA in characterizing potential impacts from the secondary formation of particulate matter. The draft guidance recommends an analytical framework for the Tier I estimation of secondarily formed particulate matter using MERPs. The application of these novel recommendations are neither binding nor prescriptive for the reviewing authority noting a potential for case-specific factors of influence. The Department evaluated AGDC's characterization of secondarily formed particulate matter on a case-specific basis. It found their approach sufficient to identify areas of maximum ambient impact(s) within the modeled domain.

The Department notes that the computational estimation of impacts attributable to the photochemical transformation of emissions from off-site sources is a non-trivial effort. An abundance of confounding variables may offer avenues for further research, but spatial and temporal uncertainty encumbers the development of consistently meaningful estimates for many regulatory applications of limited scope. Beyond informed application of the aforementioned tools, there appears to be no regulatory authority compelling an applicant to consider the secondarily-formed impacts from an off-site source that has not received an air quality permit for their proposed operations.

6.15. (NPCA) The permit fails to include enforceable limits to address impacts to the AQRVs at the Class I areas. [comment paraphrased]

Department Response: The Department understands that the Commenter disagrees with the representativeness of AGDC's modeled assumptions, the Department's evaluation of their model-estimated impacts, and its findings regarding 40 C.F.R. 52.21(p). It does not find that the inclusion of enforceable limits is warranted based on the following facts and findings.

AGDC performed analyses of the potential impacts within Class I areas in accordance with the PSD requirements under 40 C.F.R. 52.21. The Department provided notification to the U.S. Fish and Wildlife Service and National Park Service on 12 October, 2017 in accordance with 40 C.F.R. 52.21(p). It reviewed AGDC's analyses observing appropriate regulatory guidance and case-specific aspects of significance. The Department found that the proposed operation of the Liquefaction Plant stationary source will not cause or contribute to adverse impacts to air

[20] Draft Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program (EPA-454/R-16-006); December 1, 2016.

quality-related values or violations of increment within the Class I areas subject to PSD review. It generally found AGDC's modeled assumptions to be conservative.

The Department notes that it found AGDC's proposed mid-stream sources are not aggregated with the Liquefaction Plant stationary source for the purposes of PSD review; see the response to Comment 12.1. Impacts from AGDC's mid-stream sources will be considered in accordance with the regulatory requirements appropriate for their respective permit classification(s).

The Department also notes that AGDC has since amended their application to rely upon SCR for their proposed fuel gas-fired turbines; see the response to Comment 2.1. The emissions of reactive species impacting air quality-related values will be lessened through the use of SCR.

6.16. (NPCA) The Class I modeling analysis is incomplete, inaccurate and inconsistent in its assumptions. [comment paraphrased]

Department Response: The Department understands that the Commenter disagrees with the representativeness of AGDC's modeled assumptions, the Department's evaluation of their model-estimated impacts, and its findings regarding 40 C.F.R. 52.21(k).

The Department found that AGDC's analyses of Class I impacts satisfied the PSD requirements of 40 C.F.R. 52.21(k) and that the proposed operation of the Liquefaction Plant stationary source will not cause or contribute to violations of increment within the Class I areas subject to PSD review; see the response to Comment 6.15 for a representative basis. The operational assumptions and model inputs used to characterize AGDC's marine and flaring impacts are described in their application materials. The Department's findings regarding these assumptions and inputs are provided in its Modeling Report.

The Commenter suggests that AGDC's Class I analyses should include an analytical evaluation of secondary formation from proposed off-site sources that have yet to obtain required permitting. The Department is not requiring this level of analysis for the bases described in the response to Comment 6.14. The impacts from secondary formation attributable to these sources will be addressed, as warranted, in accordance with their case-specific application requirements.

The Department notes that it found AGDC's proposed mid-stream sources are not aggregated with the Liquefaction Plant stationary source for the purposes of PSD review; see the response to Comment 12.1. Impacts from AGDC's mid-stream sources will be considered in accordance with the regulatory requirements appropriate for their respective permit classification(s).

The Department also notes that AGDC has since amended their application to rely upon SCR for their proposed fuel gas-fired turbines; see the response to Comment 2.1. The emissions of reactive species impacting air quality-related values will be lessened through the use of SCR.

6.17. (NPCA) ADEC's public notice failed to provide the degree of increment consumption expected at the source at the Class I areas. The Comment asserts that the Department did not provide AGDC's predicted amount of increment consumption within Class I areas during public comment; the draft permit was defective because of this; and a new public notice be provided that includes the former information. [comment paraphrased]

Department Response: The Department provided a 30-day period for public comment on its preliminary decision to approve AGDC's PSD application for the Liquefaction Plant stationary source on September 11, 2020. It extended this period an additional 30 days on October 11, 2020 at the request of the National Park Service and Ms. Sara Laumann, on behalf of the Commenter. The Department subsequently provided a third 30 day period of comment to allow public stakeholders to consider new or revised information.

AGDC's application materials and modeling files were made available during the comment periods. These materials and files show AGDC's estimated increment consumption within the Class I areas subject to review and the approach used to estimate them. The Department's Modeling Report includes a tabular summary of their estimated increment impacts within Class II areas processed in AERMOD. Its findings in Sections 7.1 and 10 indicate that AGDC's estimated impacts do not cause or contribute to violations of the maximum allowable increases within Class I areas in comport with 40 C.F.R. 52.21(k). The Department is, therefore, not providing an additional period for public comment.

6.18. (NPCA) ADEC erred in categorically excluding construction emissions from the air quality analysis. The comment asserts that AGDC's ambient demonstration did not include modeled estimates of impacts from their proposed construction emissions; this level of analysis is needed given their scope of proposed operations; and their demonstration is inaccurate and misleading in the absence of the former analysis. [comment paraphrased]

6.19.

Department Response: AGDC provides a discussion of their modeled and non-modeled operational scenarios under Sections 4.1.1 and 4.1.2 of their Modeling Report; they discuss their construction-related emissions under Section 4.1.3. AGDC's ambient demonstration is based on their 'normal operations' modeled scenario. The Department found that the operational assumptions and model inputs associated with this scenario are generally conservative among those considered. A review of the model inputs indicate that this scenario accounts for impact-driving equipment and processes that will be included during the proposed construction

effort. The Department provided an associated discussion and findings under Section 5.6.3 of its Modeling Report.

6.20. (NPCA) ADEC erred in equating the soils and vegetation impact analysis with the NAAQS analysis. The comment asserts that the Department's evaluation of AGDC's additional impacts under 40 C.F.R. 52.21(o) is wholly inadequate; a comprehensive and specific analyses of soil and vegetation is required; and potential impacts from AGDC's proposed mid-stream facilities should be considered in evaluating the former. [comment paraphrased]

Department Response: AGDC provided both qualitative and quantitative approaches to demonstrate compliance with the additional impact analyses under 40 C.F.R. 52.21(o). The Department considered the information in their analyses, application materials, and supplemental submissions to evaluate the potential for adverse impacts. It also considered the estimated results of ambient pollutant modeling for comparison to the secondary National Ambient Air Quality Standards (NAAQS). The secondary NAAQS were developed to be protective of public welfare. Congress stated in Section 302(h) of the Clean Air Act that these welfare-based criteria include effects upon soils and vegetation; see Section 9.3 of the Department's Modeling Report. The Department separately found that source-driven deposition will not cause or contribute to adverse impacts or violations of increment within the Class I areas subject to PSD review; see the response to Comments 6.4 and 6.15.

The language of 40 C.F.R. 52.21(o)(1-3) does not prescribe an exhaustive procedure to estimate potential impacts among flora within the greater domain of project impacts. Such an approach is impractical as it fails to balance the need to identify potentially adverse project-related impacts with a practical interpretation of applicable regulation. The Department found that AGDC advanced a reasonable and well-understood approach to meet the PSD requirements under 40 C.F.R. 52.21(o).

The Department notes that it found AGDC's proposed mid-stream sources are not aggregated with the Liquefaction Plant stationary source for the purposes of PSD review; see the Department's response to Comment 12.1. Impacts from AGDC's mid-stream sources will be considered in accordance with the regulatory requirements appropriate for their respective permit classification(s).

6.21. (NPCA) ADEC's use of sensitivity modeling fails. The comment asserts that AGDC's ambient demonstration included errors as a consequence of observing the recommendations of EPA's 2005 Guideline; the demonstration was developed using outdated air quality modeling studies used in support of their NEPA analyses; the modeling tools and relevant emissions data are outdated; the Department's sensitivity studies represent a misguided attempt to defend flawed modeling; it should have instructed the applicant to update their demonstration to reflect current modeling procedures and standards; and the Department erroneously chose a

convoluted process to defend its reliance on outdated dispersion modeling. [comment paraphrased]

Department Response: The Department understands that the Commenter disagrees with the methodologies AGDC used to support their ambient demonstration. The Department also understands that the Commenter disagrees with its evaluation of AGDC's demonstration and places an emphasis on the assumed efficacy of unspecified sensitivity studies. The Department, nevertheless, is unable to identify specific or actionable elements of concern in the language advanced by the Commenter. It, therefore, is providing a general recommendation to refer to its Modeling Report for detail germane to AGDC's ambient demonstration, the Department's associated findings, and the factual and/or regulatory bases supporting those findings.

The Department notes that it performed a review of AGDC's ambient demonstration in comport with relevant guidance and in observation of the requirements for PSD applications under 40 C.F.R. 52.21.

6.22. (NPCA) ADEC's modeling analysis failed to address secondary emissions associated from growth impacts. [comment paraphrased]

Department Response: The Department understands the Commenter is referring to potential secondary emissions impacts from AGDC's proposed mid-stream facilities.

The Department notes that it found AGDC's proposed mid-stream sources are not aggregated with the Liquefaction Plant stationary source for the purposes of PSD review; see the Department's response to Comment 12.1. Impacts from AGDC's mid-stream sources will be considered in accordance with the regulatory requirements appropriate for their respective permit classification(s).

6.23. (NPCA) ADEC's assessment of NAAQS exceedances differs from FERC's. [comment paraphrased]

Department Response: AGDC's application to construct the Liquefaction Plant stationary source was prepared in observance of the requirements for PSD permits. These requirements include case-specific evaluations of ambient air quality under 40 C.F.R. 52.21. The Department reviewed AGDC's ambient demonstration in consideration of the applicable PSD requirements, relevant guidance, and additional information as it was made available. This review was performed in comport with the authority under 18 AAC 50 and AS 46.14. The Department found that AGDC's ambient demonstration satisfied the requirements for PSD permits. Detail regarding the appropriateness of AGDC's approach to meet discrete regulatory requirements is provided in the Department's Modeling Report. Detail on the assumptions of their 'normal operations' modeled scenario and its anticipated conservatism is provided in AGDC's application materials.

The Department notes that AGDC relied, to the extent possible, upon analyses prepared in support of NEPA to meet the PSD requirements of 40 C.F.R 52.21; see the response to Comment 6.6 for detail.

6.24. (NPCA) ADEC's proposed permit fails to include enforceable permit conditions that reflect the ambient air boundary modeling assumptions. The commenter asserts that AGDC's use of the fenced property boundary as their assumed ambient air boundary is unreasonable; the 500 foot safety stand-off from the marine terminal is similarly unsupported; the Department did not advance a sufficiently robust basis in support of its findings regarding the ambient air boundary; enforceable terms and conditions are required to preclude public access; and AGDC would be allowed to emit more pollution, possibly with fewer controls, than otherwise lawful in the absence of these requirements. [comment paraphrased]

Department Response: AGDC's assumed ambient air boundary was developed observing relevant EPA guidance and well-established regulatory precedent. The Department reviewed their approach and found it appropriate as described in Section 5.12 of its Modeling Report. It is unable to identify a basis for the assertion that AGDC may emit more pollution, with fewer controls, than otherwise lawful if no restrictions are imposed.

The Department understands that the Commenter is unable to locate information cited in its Modeling Report supporting its findings regarding AGDC's assumed ambient air boundary. The cited permit, Air Quality Control Minor Permit AQ0957MSS03 for PacRim Coal, LLC's Chuitna Project, employed similar approaches in developing their ambient air boundary. The information relevant to the comment at-hand is situated in the Modeling Report for PacRim's permit under the section header "Ambient Air Boundary" and is also present within their application materials.

The public may request any document associated with the discoverable record of a project using the appropriate request process for public records. The Department's form is available on its website at https://dec.alaska.gov/online-services/.

7. Permit Language

7.1. Chickaloon Commented – Second, the permit should explicitly allow DEC to make announced visits to determine compliance.

Department Response:
Preliminary Permit Condition 32 from Section 7 (Standard Permit Conditions) contains standard language that the Department inserts in permits to allow for both announced and unannounced inspections of facilities. Condition 32 states the following:

32. The Permittee shall allow the Department or an inspector authorized by the Department, upon presentation of credentials and at reasonable times with the consent of the owner or operator to

32.1 enter upon the premises where an emissions unit subject to this permit is located or where records required by the permit are kept;

32.2 have access to and copy any records required by this permit;

32.3 inspect any stationary source, equipment, practices, or operations regulated by or referenced in the permit; and

32.4 sample or monitor substances or parameters to assure compliance with the permit or other applicable requirements.

7.2. Chickaloon Commented – Exceedances of the air permit that threaten public health should be reported to the local community, not just provided to DEC (Permit Condition 23).

- Reporting to DEC is allowed "as soon as possible after the event is discovered"; this should be modified to "as soon as possible and not more than 24 hours after…"

Department Response: Condition 23 (including its sub-conditions) is derived from the Department's Standard Permit Condition (SPC) III - Excess Emissions and Permit Deviation Reports. Under 18 AAC 50.346(a), "For a construction permit or Title V permit, the department will use the standard permit condition in this subsection, 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…" SPC III has been to public comment during regulation updates and has repeatedly been one of the most commented on SPCs. The Department finds this condition will adequately meet the requirement for the Permittee to report excess emissions and permit deviations.

7.3. AGDC Commented – Permit Page 34, Section 9: Two typos for spelling of Department (missing 't') associated with the April 28, 2020 and June 18, 2020 listings.

Department Response: The Department corrected these typographical errors.

7.4. AGDC commented on the following aspects of the TAR:

Page 20 item (c): The indication after Water/Steam Injection showing (ULSD) appears to be a typo, as ultra-low sulfur diesel would not be applicable for gas-powered generators.

Page 39, Table 5-3: The Emission Reduction (tpy) should be .84 tpy (rather than .90) per AGDC's Sept. 2018 BACT analysis response to ADEC's completeness requests.

Appendix C, page 3 – one table is missing a number and should be Table C-5, which means the second table on that page should be C-6.

Department Response: The Department corrected these typographical errors.

7.5. AGDC commented on the following aspects of the Modeling Report:

Page 33 (7.2): Typo: Kenai NWE should be Kenai NWR.

Page 36, section 9.3, second paragraph: Reference to Attachment 10 of Resource Report 9 should be Attachment 10 of AGDC's permit application.

Department Response: The Department has revised the cited language as requested to correct typographical errors.

7.6. NPCA Commented – "ADEC Allows for Use of Alternative Test Methods that are not EPA-approved.

- Permit Condition 4.2 the stationary source's projected annual rate of emissions that will occur from July 1 to the following June 30, based upon credible evidence of actual annual emissions emitted during the most recent calendar year or another 12 month period approved in writing by the Department, when demonstrated by the most representative of one or more of the following methods:

  d. *other methods and calculations approved by the Department*, including appropriate vendor-provided emissions factors when sufficient documentation is provided.[21]

- Permit Condition 35.7 Source testing for emissions of any contaminant may be determined *using an alternative method approved by the Department* in accordance with 40 C.F.R. 63 Appendix A, Method 301.[22]

- Permit Condition 36. Test Deadline Extension. The Permittee may request an extension to a source test deadline established by the Department. The Permittee may delay a source test beyond the original deadline only if the extension is *approved in writing by the Department's* appropriate division director or designee.[23]"

Department Response: The Department notes that the first referenced instance is from the Department's Standard Permit Condition (SPC) I – Emission Fees. Under 18 AAC 50.346(a), "For a construction permit or Title V permit, the department will

[21] Draft permit at 3.
[22] Draft permit at 32.
[23] Draft permit at 32-33.

use the standard permit condition in this subsection, 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…" These SPCs have been fully open to the public process during routine SPC updates to regulation and have wide industry and stakeholder consensus on their proper application and regulatory basis.

The referenced instances from the General Source Test Requirements (Section 8 of the permit) are the un-edited versions used in permit development drafts in both of the Department's Title V Operating Permit and Title I (Minor and Construction Permit) permit series. The Department finds these conditions will adequately meet the requirement for the Permittee to accurately source test and will not result in the use of test methods that are less accurate than those approved by EPA.

8. Miscellaneous Comments

8.1. Chickaloon Commented – First we object to construction of another large facility that ties our state economy to the fossil fuel industry.

- We need to be transitioning jobs and the state economy away from fossil fuels.
- Although LNG is labeled a "cleaner" fuel, the plant will heavily rely on diesel fuel. It will also engage in flaring. Both contribute to the already heavy load of greenhouse gases in our atmosphere. Currently our oceans are absorbing much of this load – with resulting declines in pH that affect shellfish directly, that increase harmful algal blooms, and that reach to and kill off critical plankton at the bottom of the food chain potentially affecting aquatic life from salmon to seabirds. This is not how we steward the land and waters.
- The air permit states, *"No person may permit 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."* Chickaloon goes on to state: (permit condition 25). It is becoming increasingly clear how fossil fuel extraction, refining, and transport are damaging the stable climate upon which we all depend, including the populations of plants, animals, and people.

Department Response: The Department notes that all the regulatory requirements were followed in developing the Liquefaction Plant's construction permit, including a greenhouse gas BACT section for each emissions unit type. Condition 25, which is based on Standard Permit Condition II – Air Pollution Prohibited, is intended to cover acute excess emissions that may influence the immediate airshed, not the global environment. This condition is not intended to cover the cumulative effect of emissions leading to an increase in greenhouse gases concentrations in the atmosphere that is contributing to a changing climate. Therefore, the Department has no regulatory basis to reject AGDC's application for a PSD construction permit for the Liquefaction Plant based on greenhouse gas emissions. Further, the proper

place for these issues to reside is within the federally-mandated NEPA process, where one possible alternative for selection is the "no action" alternative. The federal land managers who participated in and selected the construction alternative in the EIS well in advance of the application process. This comment, while very intuitive and respected, is outside the scope of this application.

8.2. Chickaloon Commented – Technical analysis report Page 3. "After passing through the mercury removal bed…". How much mercury will be removed? Are these activated carbon beds? Where will this material be disposed of?

Department Response: The Department contacted AGDC for further explanation on the process of the mercury removal beds and is including their response below in its entirety.

***Mercury Removal Bed** – The inlet gas treating, mercury removal, and dehydration system for the Liquefaction Plant includes activated carbon mercury adsorber beds. Activated carbon systems in mercury adsorber beds have been used for mercury removal by the natural gas industry, including LNG applications, for more than 40 years. Over this period, an extensive performance database has been developed from laboratory testing and field studies. Activated carbon products and technologies are proven safe and effective and are considered the benchmark of performance for LNG applications under a wide variety of treatment conditions. The service life of these systems can range from 5 to 10 years to up to 20 years. Prior to construction, technical "cradle-to-grave" support would be procured from specialized activated carbon treatment vendors, which would include design, installation, and commissioning of the mercury adsorber beds, as well as removal and disposal of spent carbon media.*

Activated carbon treatment vendor services would also include the development of procedures for removal and safe disposal of the spent activated carbon containing adsorbed mercury. The general procedures that would be included are as follows:

- *During facility operations, the activated carbon granules in mercury adsorber beds would become spent or exhausted and would need to be replaced.*
- *Depending on the final design, the spent activated carbon would either be removed from the vessel, or the entire vessel could be exchanged with another adsorber bed unit filled with fresh carbon media.*
- *The removal and management and/or disposal of spent carbon media or vessels would be performed in accordance with applicable regulations by a qualified third-party contractor.*
- *Spent activated carbon would be transported off site and managed in compliance with hazardous waste regulations. Likely scenarios would be*

disposal at an Environmental Protection Agency (EPA)-permitted hazardous waste landfill or treatment at a permitted thermal treatment site where material is destroyed in permitted, high-temperature kilns with proper scrubbing of exhaust gases.

8.3. NPS Commented – "…we encourage ADEC to continue ongoing discussions with us towards the goal of improving notification procedures for future permits."

Department Response: The Department is committed to ongoing dialogue with NPS to ensure timely and complete notification procedures to the federal land managers are followed for future PSD construction permits.

8.4. NPCA Commented, "ADEC's proposed action fails to contain an analysis of whether any NSPS apply, and if so, whether the proposed Liquefaction plant will meet those standards." … "Furthermore, as discussed in the Stamper Report, ADEC's proposed BACT limits for the diesel-fired units (the fire pump and the and auxiliary air compressor engine) are less stringent than the applicable NSPS standards."

Department Response: The Department does not include NSPS and NESHAP requirements in construction permits. NSPS and NESHAPs requirements (18 AAC 50.040(a) and (b)-(c)) are adopted as they apply to a Title V source. Thus, those requirements will be included in the Title V operating permit that will be issued to the Liquefaction Plant after the stationary source begins operations and triggers Title V permitting.

The Department has not set BACT emissions limits on the diesel-fired units that are less stringent than the applicable NSPS standards. See response to Comment 4.9 for further explanation.

9. Construction Issues

9.1. NPCA Commented – "ADEC's Analysis Fails to Include a Detailed Schedule for Construction and Operation of the Sources. The PSD permit application must include, "at a minimum, information on the location, design capacity, and *typical operating schedule of the source, a detailed schedule for construction*, and a

description of the control technology that is proposed as BACT,[24] and these requirements are in Alaska's regulations.[25]"

NPCA also commented regarding the requirement under 40 C.F.R. 52.21(r)(2) that requires the permittee commence construction within 18 months of receiving a permit.

Department Response: The Department is not required to include a detailed schedule for construction and operation of the source. Instead, the applicant is required to provide this information in their application under 40 C.F.R. 52.21(n)(1). This information was provided by the applicant and is available on the Department's website[26] under the attachment "02 General Project Info Resource Report 1." In this attachment the project description section begins on PDF page 90 and the construction schedule begins on PDF page 198.

The Department also notes that Condition 2 requires the permittee to commence construction within 18 months of the issuance of the permit unless granted an extension in writing from the Department, as required under 40 C.F.R. 52.21(r)(2).

10. Health Issues

10.1. Chickaloon Commented – Is there potential for the emission of hydrogen sulfide?

Department Response: The gas entering the Liquefaction Plant will have already been treated to the standards for pipeline quality natural gas at the Gas Treatment Plant on the North Slope. Therefore, there is minimal risk of hydrogen sulfide emissions at the Liquefaction Plant from the pipeline connecting these two stationary sources as no additional hydrogen sulfide will be added nor produced.

11. Fugitive Dust

11.1. Chickaloon Commented – Fugitive dust control is only required from May-September (permit condition 10.1). Winds occur all year, therefore dust control should be required all year, and is feasible with chemical suppressants as are used at mining sites. This will require very good stormwater control.

- Regardless of the time of year applied, if chemical suppressants are utilized, where does runoff water carrying these chemicals end up? Is it treated? It should not be discharged directly to water bodies.
- The permit allows AGDC to submit a map of proposed air monitoring locations within 6 months from construction. Will this be part of a new public comment

[24] *Alabama Power* at 351. (emphasis added)
[25] 18 AAC 506.040(h)(12), adopting by reference 40 C.F.R.§ 52.21(n)(1).
[26] https://dec.alaska.gov/air/air-permit/liquefaction-plant-application/

period? If not, how can the public comment on the appropriateness of the locations without any information?

- Data collected through continuous or spot check air monitoring (permit condition 10.2) should be provided on a publicly accessible database.

Department Response: The Department revised Condition 10.1 to remove the months of May through September to ensure that fugitive dust control is conducted on a year-round basis.

The Department revised Condition 10.2 to require one or more upwind PM-10 and PM-2.5 monitoring sites to ensure that monitoring is conducted adequately both upwind and downwind for ***both*** *PM-10 and PM-2.5 (emphasis added). Additionally, Condition 10.2b requires AGDC to submit a Quality Assurance Project Plan (QAPP) to the Department for approval for the PM-10/PM-2.5 monitoring effort with 60 days of the Department's approval of the monitoring locations. The Department finds this to be adequate to ensure that the monitors are appropriately sited during the construction phase to monitor fugitive dust. The Department notes that the public will not have an opportunity to comment on the appropriateness of monitor siting, but that the monitoring will ensure continued compliance with ambient air quality standards.*

There will also be a manual or automated system that continuously reviews the PM-10 and PM-2.5 monitoring data and requirements to act if measured concentrations exceed the respective thresholds in Condition 10.2d to ensure continued compliance with the ambient air quality standards. The hourly PM-10 and PM-2.5 concentrations will be uploaded to a publicly accessible database daily.

The Department acknowledges that chemical suppressants used to control fugitive dust should not be discharged directly into water bodies. This should be adequately addressed in a Storm Water Pollution Prevention Plan (SWPPP) which is required by the Alaska Department of Natural Resources and outside the scope of this air permit.

11.2. EPA Commented – Permit Section 4; Condition 10 (fugitive dust). The permit requires fugitive dust controls during summer months only. There may be rare events outside of the May – Sept. period where conditions are favorable for excessive fugitive dust emission. The EPA recommends Alaska DEC consider adding a requirement in the permit that also requires responsive fugitive dust mitigation in circumstances where excess dust emission is observed or measured, regardless of the time of year.

Department Response: The Department revised Condition 10.1 to remove the months of May through September to ensure that fugitive dust control is conducted on a year-round basis.

12. Aggregation of GTP, Compressor Stations and Liquefaction Plant

12.1. NPCA Commented – "Contrary to PSD permitting requirements, neither AGDC nor ADEC included expected emissions associated with the planned 800-mile pipeline that would transport natural gas from the North Slope to Nikiski. By not aggregating the emissions from the pipeline, gas treatment plant and compressor stations with those of the Liquefaction plant, AGDC would be allowed to treat the compressor stations and gas treatment plan as "minor" sources for air permitting purposes—a fact which will allow those facilities to escape the Clean Air Act's technology-based requirements (i.e., Best Available Control Technology (BACT), limitations on criteria air pollutants) and Maximum Achievable Control Technology (MACT), limitations on hazardous air pollutants) reviews applicable to "major" sources. Permitting the project as one PSD source would mean that the project's cumulative impacts on air quality including Class I AQRVs would need to be assessed collectively, which would best ensure that the goals of the PSD program are met."

Department Response: The Department finds that the proposed components of the Alaska LNG Project (including the Gas Treatment Plant, heater and compressor stations, pipeline, and Liquefaction Plant) do not meet the definition of a stationary source.

NPCA references the "single source" three-part test in 40 C.F.R. 40 C.F.R. 52.21(b)(5) & (6). 40 C.F.R. 40 C.F.R. 52.21(b)(5) states that a "stationary source means any building, structure, facility, or installation which emits or may emit a regulated NSR pollutant. 40 C.F.R. 52.21(b)(6)(i) goes on to define that a "building, structure, facility, or installation means all of the pollutant-emitting activities,

1. which belong to the same industrial grouping,
2. are located on one or more contiguous or adjacent properties, and
3. are under the control of the same person (or persons under common control) except the activities of any vessel."

The Gas Treatment Plant, mid-stream facilities, and Liquefaction Plant associated with the Alaska LNG Project do not meet the second part of the three-part test, "are located on one or more contiguous or adjacent properties." The Alaska LNG Project consists of a Gas Treatment Plant on Alaska's North Slope and a Liquefaction Plant in Nikiski with an approximately 800-mile pipeline between the two PSD major facilities with compressor and heater stations located along the way.

NPCA notes several instances that single stationary source determinations were made for facilities that were not located immediately adjacent to each other

1. *An EPA finding for an Anheuser-Busch brewery and the Nutri-Turf landfarm located about 6 miles away that disposed of the brewery's wastewater which was transported via pipeline.*[27]

2. *The American Soda Commercial Mine and Processing Plant in Colorado that were planned to be 35 to 40 miles apart and connected by pipeline.*[28]

3. *The Great Salt Lake Minerals plant and a pump station in Utah that were approximately 21.5 miles apart.*[29]

4. *The District Energy St. Paul Combined Heat and Power Plant and Environmental Wood Supply in Minnesota which supplied biomass-fuel to the power plant approximately three miles away.*[30]

A salient difference between the Commenter's cited determinations and the Department's finding is the scale of the distance between the facilities. The Alaska LNG Project stretches from the North Slope to the Cook Inlet of Alaska. The geographic distance between the Gas Treatment Plant and the Liquefaction Plant is approximately the same distance from Atlanta, GA to Milwaukee, WI. This distance also includes multiple air sheds as the Liquefaction Plant will be located south of the Alaska Range and the Gas Treatment Plant to the north of the Brooks Range. After careful consideration, the entirety of the Alaska LNG Project fails to meet the second portion of the three-part test, "location on one or more contiguous or adjacent properties."

A July 18, 2017, decision by the Circuit Court of the City of Richmond in The Virginia Chapter of the Sierra Club v. The Virginia State Air Pollution Control Board and The Virginia Electric and Power Company CL16-3770[31]*, upheld a PSD Permit issued by the state of Virginia. In this case, the Virginia Electric and Power Company had applied for a PSD permit for the Greensville Power Station located in Greensville County, VA and was granted the permit by the Virginia Department of Environmental Quality. The permit was appealed by the Sierra Club who requested*

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[27] *See* EPA Memorandum with Subject: "Analysis of the Applicability of Prevention of Significant Deterioration (PSD) to the Anheuser-Busch, Incorporated Brewery and Nutri-Turf, Incorporated Landfarm at Fort Collins, Colorado," available at https://www.epa.gov/nsr/analysis-applicability-psd-anheuser-busch-incorporated-brewery-and-nutri-turf-incorporated (Aug. 27, 1996).

[28] *See* EPA Letter from Richard R. Long, Air and Radiation Program, EPA Region VIII, to Mr. Dennis Myers, Air Pollution Control Division, Colorado Department of Public Health and Environment, at 1, available at https://www.epa.gov/nsr/american-soda-multi-facility-source-determination (April 20, 1999).

[29] *See* EPA letter from Richard R. Long, Air Program, EPA Region VIII, to Lynn R. Menlove, New Source Review Section, Utah Department of Environmental Quality, at 1-2, available at https://www.epa.gov/nsr/great-salt-lake-minerals-source-determination (Aug. 8, 1997).

[30] *See* EPA letter from Pamela Blakely, Air Permits Section, EPA Region V, to Don Smith, Air Quality Permits Section, Minnesota Pollution Control Agency, at 1, available at https://www.epa.gov/nsr/single-source-applicability-determination-environmental-wood-supply-llc-and-district-energy-st (March 23, 2010).

[31] The Virginia Chapter of the Sierra Club v. The Virginia State Air Pollution Control Board and The Virginia Electric and Power Company CL16-3770 [July 28, 2017].

that the stationary source should include the Atlantic Coast Pipeline (ACP) as part of the stationary source for the purposes of its PSD permit. The Sierra Club argued that the Greensville Power Station and the over 600-mile long, interstate ACP are a single "building, structure, facility or installation" under the PSD rules. The Sierra Club asked the court to accept a definition of contiguous that includes not only sources that are "touching," but also sources that are "connected throughout in an unbroken sequence." The court rejected this appeal stating:

> *The definition proposed by Sierra Club does not fall within the common sense notion of a plant because it would connect the Greensville Power Station and every connection along the 600-mile proposed ACP into one massive source." Additionally, the acceptance of a definition that includes all sources "connected throughout in an unbroken sequence" would lead to the illogical conclusion that distance has no impact on what qualifies as a building, structure, facility, or installation under 42 U.S.C. § 7411(A)(3). See Summit Petroleum v. United States EPA, 690 F.3d 733, 750 (6th Cir. 2012) (finding that an aggregation test without regard to physical proximity was "inherently unreasonable" in the oil and gas industry because it would allow the connection of "operationally related but physically distinct activities, [to which] there is little foreseeable limit to the aggregation of emission points spread out literally across the country"). For these reasons, the Board reasonably concluded that the ACP and Greensville Power Station are not a single source.*

After careful consideration, the Department finds that AGDC's proposed facilities do not meet the "common sense" notion of a single source. As explained in the preamble to the August 7, 1980 PSD rules, such a decision must be made on a case-by-case basis. Moreover, in further explaining this factor, EPA has noted that whether or not two facilities are adjacent depends on the "common sense" notion of a source and the functional inter-relationship of the facilities and is not simply a matter of the physical distance between the two facilities. However, the physical distance between two facilities is obviously a factor to be considered in deciding whether the two are close enough to be considered one source in a given situation.

The compressor stations are located approximately 90 miles apart on average from each other and the facilities are separated by multiple air sheds. The Department has weighed the information and finds that the facilities are not close enough to be considered one source under the circumstances, for the purposes of PSD applicability determinations.

Based on the above factors, the Department finds that the Gas Treatment Plant, the Liquefaction Plant, and the heater and compressor facilities located along the pipeline do not meet the "common sense" notion of a single source. Therefore, these

facilities should be treated as separate stationary sources for PSD applicability determinations.

The Department notes that it has already issued PSD Construction Permit AQ1524CPT01 for the Gas Treatment Plant; it has not yet received any applications for AGDC's proposed mid-stream source(s). When those applications are received, they will be evaluated based on the applicable regulatory guidelines.

Additionally, even though the interconnecting pipeline and compressor stations may in turn be treated as individual, minor sources, they would not escape permitting to impose any relevant technology-based Part 63 NESHAPs for area sources or minor source categories.

12.2. NPCA Commented – "If the AK LNG Project is split up into a major and minor source construction permits, then the purposes of the PSD program, including the requirement to assure that "any decision to permit increased air pollution…is made only after careful evaluation of all of the consequences of such a decision…" will not be met. "

Department Response: The Department finds that the AK LNG Project is not a single stationary source (as stated in the response to Comment 12.1), therefore the components that comprise the AK LNG Project will be evaluated as applications are received. A missing portion of NPCA's quote from Section 160(5) of the Clean Air Act states, "any decision to permit increased air pollution in any area ***to which this section applies…"*** *(emphasis added).*

The Department has already issued PSD Construction Permit AQ1524CPT01 for the Gas Treatment Plant and has not received any other applications for the mid-stream facilities. When those applications are received, they will be evaluated based on the applicable regulatory guidelines and thresholds to determine PSD applicability. However, the Department notes that if mid-stream facilities do in fact constitute minor sources under 18 AAC 50.502(c)(1), they will not be applicable to the PSD rules and therefore not applicable to the quoted text from Section 160(5) of the Clean Air Act.

12.3. NPCA Commented – "Finally, it is undisputed that the aboveground and underground pipeline itself will emit air pollution in the form of greenhouses gases, including methane, and if it is not aggregated with the rest of the AK LNG Project, it would evade the substantive requirements of the PSD program-including, most notably, a review of technologies to control greenhouse gas emissions from its above-and belowground components."

Department Response: As indicated in the Department's response to Condition 12.2, the mid-stream facilities (not including the pipeline) will be reviewed for PSD

applicability upon receipt of their permit applications. If the pipeline-associated emitting units trigger PSD review under 40 C.F.R. 52.21 (including the associated BACT and PSD limits), they will be evaluated at that time. Regardless of the nature of the pipeline's future collection of emitting units and inventory classification status at the compressor stations, the pipeline itself will be subject to regulatory review by multiple government agencies prior to construction. The Department notes that at this time we have not received applications for the pipeline or any other mid-stream facilities.

13. Extra Permit Requirements

13.1. NPCA Commented – "The Proposed Permit Fails to Demonstrate Plant Will Comply with all Federal Standards."

"ADEC's proposed action fails to contain an analysis of whether any NSPS apply, and if so, whether the proposed Liquefaction plant will meet those standards. Based on analyses and determinations by other permitting authorities for similar facilities, there appear to be several NSPS that might apply.[32], [33] ADEC is prohibited from issuing the permit for the proposed Liquefaction plant until such an analysis is conducted and a determination made that the BACT determinations will not exceed the NSPS standards.[34] Furthermore, as discussed in the Stamper Report, ADEC's proposed BACT limits for the diesel-fired units (the fire pump and the and auxiliary air compressor engine) are less stringent than the applicable NSPS standards.[35] Finally, the Order issued to the AK LNG Project by FERC indicates that "AGDC would implement various measures to reduce construction emissions, including… use of electric generators in compliance with New Source Performance Standards (NSPS) Subpart III."[36]"

Department Response: The Department did not revise the permit to include the applicable NSPS and NESHAP requirements because it finds these applicable regulations to be more appropriately included in a Title V operating permit. The Department incorporates the Federal NSPS and NESHAPS only as they pertain to a Title V source, 18 AAC 50.040(a)-(c). The Department notes that there are no BACT limits that exceed the numerical emission limits under the various Subparts in Section 111 and Section 112 of the Clean Air Act. For more information regarding 40 C.F.R. 60 Subpart IIII for EUs 11 and 12, please see the Response to Comment 4.9.

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[32] NSPS for Combustion Turbines Subpart KKKK, NSPS Subpart Db, NSPS Subpart IIII, NSPS Subpart Kb, NSPS Subpart OOOOa.
[33] *See, e.g.,* FEIS at 4-925 – 4-927.
[34] Additionally, the FEIS "determined that" several NSPS would be "applicable to one of more of the Project facilities," and ADEC did consider this information. *Id.* at 4-925 – 4-927.
[35] *See* Stamper Report at 31-33.
[36] FERC Order ¶ 202.

13.2. NPCA Commented – "ADEC's Public Notice Suggests Its Proposed Approval includes Hazardous Air Pollutants, and There is no Supporting Analysis".

Additionally, while ADEC's notice for this proposed approval indicates the Liquefaction Plant is subject to the construction permitting requirements for hazardous air pollutants (HAPs), there is nothing in the proposal covering these pollutants and the requirements. ADEC's public notice explains that "[t]he project is also classified under 18 AAC 50.316 as a major source of Hazardous Air Pollutants for formaldehyde and ethylbenzene."[37] Similarly, the Pre TAR explains that "AGDC submitted this analysis in support of their 1 May, 2018 air quality control permit application (AQ1539CPT01) submitted under the Prevention of Significant Deterioration (PSD) requirements listed in 18 AAC 50.*306 and the major source of hazardous air pollutant (HAP) requirements* listed in 18 AAC 50.316."[38] The rule cited by ADEC includes the requirements for preconstruction review for construction or reconstruction of a major source of hazardous air pollutants,[39] which suggests ADEC's proposed permit action is also intended to cover the CAA's hazardous air pollutant requirements, which is does not."

Department Response: The Department did not revise the permit to include the applicable NESHAP requirements for hazardous air pollutants because it finds these applicable regulations to be more appropriately included in a Title V operating permit. See the Response to Comment 13.1. The Department notes that there are no BACT limits that exceed the numerical emission limits under the various Subparts in Section 112 of the Clean Air Act.

The Department notes that under 18 AAC 50.306 "An owner or operator must obtain a prevention of significant deterioration (PSD) permit under this section before beginning actual construction of a new major stationary source…" Under 18 AAC 50.316 "The owner or operator of a major source of hazardous air pollutants subject to a standard under 40 C.F.R. Part 63, adopted by reference in 18 AAC 50.040, must obtain a construction permit before - (1) constructing a new major source of hazardous air pollutants subject to that standard." Upon the issue date of this permit, the owner or operator will have met these requirements by obtaining the appropriate construction permit.

14. Compliance and Enforcement

14.1. EPA Commented – **NOx Emission Monitoring.** Modeled impacts for this project indicate that the peak ambient impact is 96.7% of the 1-hour NO2 National Ambient Air Quality Standard (NAAQS). Given the size of the emission units and the

[37] Public Notice, State of Alaska, Department of Environmental Conservation Alaska Gasline Development Corporation Liquefaction Plant.
[38] PreTAR at 1.
[39] 18 AAC 50.316. Preconstruction review for construction or reconstruction of a major source of hazardous air pollutants.

modeled impact, Region 10 recommends that continuous emission monitoring systems (CEMS) for NOx be required on each of the combustion turbines. Operation of the CEMS should be verified through quarterly cylinder gas audits and annual relative accuracy test audits, in accordance with EPA Performance Specification 2.

Department Response: AGDC's ambient demonstration provides an estimated one-hour NO_2 impact that falls below the associated National Ambient Air Quality Standard. An examination of the spatial characteristics and principal drivers of this estimated impact, contemporaneously observing a general conservatism among modeled assumptions, does not appear to support a robust factual basis to implement the Commenter's recommendation, ceteris paribus.

The Department additionally notes that, while AGDC's estimated impacts fall near the probabilistic standard, AGDC has since amended their application to rely upon SCR for their proposed fuel gas-fired turbines; see the response to Comment 2.1 for detail. The use of SCR will generally lower the estimated ambient NO_2 impacts from the source.

14.2. EPA Commented – **NOx Emission Testing.** The draft permit only requires initial performance testing of two out of the six simple-cycle compressor turbines, and no periodic testing is required. As described in our earlier comment, Region 10 believes CEMS are appropriate for NOx, while testing for CO, PM-10/PM-2.5, and VOC should be required on two of six compressor turbines and one of four power turbines annually, and should rotate through the units such that each unit is tested every three or four years. All testing must follow EPA standard test methods and should comply with EPA National Stack Testing Guidance.

Department Response: The Department did not revise the NOx source testing regime because it finds it to be adequate to show initial compliance with the BACT limits. Additionally, Condition 13.2c requires the Permittee to operate and maintain temperature sensing devices to monitor the inlet temperature of each installed SCR system, which will ensure that the catalyst beds continuously control NOx emissions.

The Department will include the periodic source testing requirements in the Title V operating permit that follow EPA standard test methods and comply with the EPA Nation Stack Testing Guidance. The Department did not include a requirement to require a continuous emissions monitoring system (CEMS) because it finds that periodic source testing has been demonstrated in practice to be sufficient for ensuring continued compliance with numerical emission limits. The Department notes that the Permittee will be installing brand new turbines with vendor guarantees to meet the BACT limits in the permit. However, if periodic source tests show emission rates approaching the BACT limits, the Department can backfill CEMs requirements into the operating permit to ensure continued compliance with these limits.

The planned periodic source testing will be structured to ensure that the testing is rotated through the identical units such that each unit is tested in a rotating cycle under the conditions allowed on pages 9-10 of EPA's April 27, 2009 Memorandum on the Issuance of Clean Air Act National Stack Testing Guidance.

14.3. Chickaloon Commented – Page 4. LNG storage tanks. How will leakage be monitored at the storage tanks, and at piping throughout the facility?

Department Response: The Liquefaction Plant will be subject to New Source Performance Standards (NSPS) Subpart OOOOa, which constitutes the leak detection and repair (LDAR) regulations applicable to the facility. National Emission Standards for Hazardous Air Pollutants (NESHAP) Subpart HH LDAR regulations apply, as the plant has potential to emit more than 10 tons per year (tpy) of a single hazardous air pollutant (HAP) or 25 tpy of total HAPs (formaldehyde and ethylbenzene).

The LNG storage tanks will be designed for full containment. Current plans anticipate they will be composed of primary and secondary wall panels, primary and secondary tank floors, a suspended deck, a foundation slab, a floor slab on seismic isolation, and a reinforced outer tank dome roof. The primary and secondary wall panels will have a non-load bearing vapor barrier. Insulation materials will be installed between the inner and outer tanks to minimize heat gain from the atmosphere to the inner tank contents. The LNG storage tank leak detection instrumentation will consist of four resistance temperature detectors (RTDs) at 90-degree intervals in the bottom of the annular space (secondary bottom). Two additional RTDs will be installed notionally within the first 30 feet of the secondary wall facing the annular space. Low temperature alarms will alert operators in the event of an inner tank breach.

Piping systems will be included in a LDAR program consistent with the EPA's Leak Detection and Repair: A Best Practices Guide (2007). Fugitive volatile organic compounds and carbon dioxide equivalent emissions estimates included in AGDC's permit application and Draft Permit Appendix A, Table 12 were based on LDAR control efficiencies from Table 5-2 in the EPA's Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017.

15. Public Participation and Federal Agency Consultation Requirements

15.1. NPCA Commented – "ADEC failed to provide the public timely and complete access to the supporting record. ADEC's failure to comply with the public notice obligations are so substantial that it precludes public participation. Moreover, the limited information provided by ADEC is so defective that it rippled throughout its proposal, hampering the public's participation and ability to review and identify issues. The harm from ADEC's procedural violation is that is has deprived the public's opportunity to have its views considered by ADEC. A key statutory

objective of the Clean Air Act's PSD program is to "assure that any decision to permit increased air pollution … is made only after consideration of all the consequences of such a decision and after adequate procedural opportunities for informed public participation in the decision-making process."[40]

Consistent with EPA's regulations, to Alaska's PSD regulations require ADEC to – among other things:

(i) Make a preliminary determination whether construction should be approved, approved with conditions, or disapproved.

(ii) Make available in at least one location in each region in which the proposed source would be constructed a copy of *all materials the applicant submitted*, a copy of the preliminary determination, and *a copy or summary of other materials*, if any, *considered in making the preliminary determination*.[41]"

Department Response: The Department refutes the claim that we failed to "make available in at least one location in each region in which the proposed source would be constructed a copy of all materials the applicant submitted, a copy of the preliminary determination, and a copy or summary of other materials, if any, considered in making the preliminary determination." All of the permit application, preliminary decision material and draft permit have been available in any DEC AQ office since the date of publication, or by request electronically. The Department was contacted by NPCA on September 25, 2020, requesting the complete permit application, the Department's supporting analysis, and all correspondence to and from the Federal Land Managers (FLMs). On September 29, 2020, the permit application materials were uploaded to the Department's public notice website, except for the modeling files which were too large in file size to upload and the detailed turbine BACT cost calculations in Appendices B and C of Resource Report 6 which were submitted as confidential business information (CBI).

AGDC eventually allowed the release of all BACT application information that was previously submitted as CBI. After the removal of CBI claims by the AGDC, the Department uploaded all the application materials (minus the modeling files which were too large to post) as well as a copy of all materials the Department used in making the preliminary determination to a new website created for the Liquefaction Project on November 6, 2020. On the same day, the Department extended the public comment period of the Liquefaction Plant's Preliminary Construction Permit AQ1539CPT01 until December 10, 2020, to allow the public extra time to see all the materials. The Department also provided NPCA with the modeling files via a file transfer protocol on November 10, 2020, 30 days before the end of the public comment period.

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[40] *In re Russel City Energy*, 14 E.A.D. 159, 175 (EAB 2008), citing In re *Rockgen Energy Center*, 8 E.A.D. 536,
[41] 18 AAC 50.040 adopts by reference 40 C.F.R. § 51.166(q)(2) (emphasis added).

On December 3, 2020, NPCA's initial information request was revised after the Department denied a fee waiver for the Department's staff time to locate all the correspondence between the Department, AGDC, and FLMs. The new request asked for a new extension of the public comment period until January 11, 2021, as well as all correspondence and attachments from the FLMs that occurred between August 12, 2020 to December 3, 2020. On December 4, 2020, the Department provided the correspondence from the FLMs in a file transfer protocol. Then on December 9, 2020, the Department sent an email denying the request for the public comment extension through January 11, 2021, because the preliminary permit had already been out to public comment for 90 days which the Department felt was an adequate amount of time to review and make comments.

15.2. NPCA Commented – "There is no evidence to show ADEC provided the FLM's with the required 60-day comment period. The Clean Air Act and regulations require that written notice of a permit application and proposed PSD permit be provided to the Federal Land Manager (FLM) for a Class I area that may be affected by emissions from the proposed Liquefaction plant.[42] ADEC's SIP regulations require that it

> [P]rovide written notice of any permit application for a proposed major stationary source or major modification, the emissions from which may affect a Class I area, to the Federal land manager and the Federal official charged with direct responsibility for management of any lands within any such area. Such notification shall include a copy of all information relevant to the permit application and shall be given within 30 days of receipt and at least 60 days prior to any public hearing on the application for a permit to construct. Such notification shall include an analysis of the proposed source's anticipated impacts on visibility in the Federal Class I area.[43]

State permitting agency requirements to consult with the Federal Land Managers regarding impacts to Class I areas are an important part of the PSD permitting regulations because the FLMs are "charged with direct responsibility for management of such lands have an affirmative responsibility to protect the air quality related values (including visibility) of such lands and to consider" in consultation with the permitting agency, "whether a proposed source or modification will have an adverse impact on such values."[43] ADEC's PreTAR explains that the Department initially "notified the FWS and the NPS of the pending PSD application on 12 October, 2017. The FWS responded the same day by saying they would like to kept informed and that they wanted to discuss the AQRV evaluation. The NPS

[42] CAA § 165(d)(2)(A); 40 C.F.R. § 52.21(p) (Sources Impacting Federal Class I Areas)(2011).
[43] 8 AAC 50.040(h)(14) ADEC adopts by reference, 40 C.F.R. § 52.21(p). Moreover, "[i]rrespective of distance from a proposed source to the Class I area, permit applicants are legally obligated to demonstrate that their proposed facilities will not cause or contribute to air pollution in violation of any PSD increment, including the Class I increments. CAA § 165(a)(3)(A), 42 U.S.C. § 7475(a)(3)(A); 40 C.F.R. § 52.21(k)(2)." *NMU* at 329.

expressed their interest during a 24 October, 2017 teleconference with the FLMs."[44] There is no other information in the PreTAR regarding ADEC's consultation with the FLMs. Furthermore, the PSD program requires that EPA consult with ADEC along with the FLMs regarding the FLM concerns. There is nothing in the record to show this occurred.[45]"

Department Response: The Department worked with the FLMs (both NPS and FWS) during the permitting process for the Liquefaction Plant Construction Permit AQ1539CPT01. Due to the size of the application files and the claim of CBI information, the Department requested AGDC submit all permit application materials directly to the FLMs. AGDC submitted the application materials with an electronic transmittal on June 4, 2018, more than two years before the preliminary construction permit was public noticed. The Department had email exchanges with NPS and FWS staff on October 29, 2019, and December 9 and 10, 2019, checking in on the status of the application and preliminary permit. Department staff held a meeting with AGDC, NPS, and FWS staff on January 15, 2020 discussing the project. On February 11, 2020 the NPS sent notification to AGDC that they had received additional modeling files that had been requested during the January 15, 2020 meeting.

On March 3, 2020, the NPS submitted a staff level technical review of an SCR analysis for the turbines at the Liquefaction Plant to the Department. However, this review was focused on the BACT analyses as they relate to economic feasibility for selecting SCR as BACT for the turbines and not whether the proposed new major stationary source may have an adverse impact on visibility or air quality-related values in the Federal Class I area (Denali National Park) as outlined in 40 C.F.R. 52.21(p)(3) and (4). Therefore, because no visibility analysis was provided to the Department from the FLMs, the Department was not required to provide in the public notice an explanation of said visibility impact analysis, or why the Department finds that such an analysis does not demonstrate to the satisfaction of the Department that an adverse impact on visibility will result in the Federal Class 1 area.[46] However, the Department notes that the SCR analysis provided by the NPS is now immaterial as AGDC has now selected SCR to control the gas-fired turbines with a NOx emissions limit of 2 ppmv at 15 percent O_2, as was recommended by the NPS in their analyses and comments on the preliminary permit.

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[44] PreTAR at 3. The PreTAR includes citations to emails, but those emails were not included as part of the proposed permit action. (Email from James Renovatio (Department) to Andrea Stacy (NPS) and Catherine Collins (FWS), *Alaska LNG – Liquefaction Class I impacts for proposed PSD permitting*; 12 October, 2017; Email from Catherine Collins (FWS) to James Renovatio and Alan Schuler (Department), *Re: Alaska LNG – Liquefaction Class I impacts for proposed PSD permitting*; 12 October, 2017.) *Id.*

[45] Although several of the emails NPCA obtained through its records request to ADEC reveal that EPA was included in emails regarding the FLMs concerns about not receiving prior notice of the Liquefaction Plant, EPA was not involved in the subsequent communication emails between ADEC and FLMs where the proposed permit for the Liquefaction plant was discussed.

[46] 40 C.F.R. 52.21(p)(3)

15.3. NPCA Commented – "There is no evidence demonstrating that ADEC provided notice and communicated with EPA. ADEC is also required to provide notice to EPA in its implementation of the PSD program. This notice consists of a copy of the permit application for sources subject to PSD and notice of every action related to the consideration of the permit.[47] ADEC's proposed permit information also failed to include this information. Therefore, NPCA requested information from the State regarding "[a]ll ADEC records regarding communication with EPA in its oversight role of this proposed permit,"[48] and despite the fact that the PSD regulations required this communication and that EPA generally provides comments on proposed PSD permits in its oversight role, as discussed above, NPCA was informed a written records request and agreement to pay fees were required before ADEC would release the communications. Thus, NPCA never received this information and was unable to determine whether the required notifications were provided and whether EPA expressed any concerns with either the permit application or ADEC's proposal to approve the permit."

Department Response: The Department provided notice of the permit application to EPA Region 10 and had follow-up conversations during the permitting process for the Liquefaction Plant Construction Permit AQ1539CPT01. Due to the size of the application files and the claim of CBI information, the Department requested AGDC submit all permit application materials directly to the EPA. AGDC submitted the application materials with an electronic transmittal on June 4, 2018, more than two years before the preliminary construction permit was public noticed. The Department public noticed AGDC's other PSD construction permit for the Gas Treatment Plant (AQ1524CPT01) on July 12, 2019, and issued the final permit on August 13, 2020. During this timeframe the Department had numerous email exchanges and discussions with EPA Region 10 regarding the status of the AK LNG Project. The first week of September 2019 EPA Region 10 and the Washington Department of Ecology hosted a Title V workshop where Department staff had discussions about the proposed project's permitting status with EPA Region 10's Air Permit Program Lead, Doug Hardesty.

In October 2020, Department staff led a panel on Public Noticing at the EPA Region 10 virtual NSR workshop that included Doug Hardesty of EPA Region X OAR. In meetings leading up to this panel in August and the first week of September, Department staff mentioned to Doug Hardesty that the Liquefaction Permit would be going to public notice shortly. EPA Region 10 was also included in the public notice for the Liquefaction Plant's construction permit on September 11, 2020 and commented on the preliminary permit. The Department notes that none of EPA Region 10's comments on the preliminary permit expressed concerns about a lack of communication from the Department.

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[47] These regulatory requirements are often memorialized between state permitting agencies and EPA regional offices in what's called a "Performance Partnership Agreement" ("PPA") that provides the details on communications like CAA permits.
[48] NPCA letter to ADEC at 2 (Oct. 29, 2020).

15.4. NPCA Commented – "The proposed permit allows for amendments to the permit that the public will not have an opportunity to review and comment on.

The following permit conditions allow siting of ambient monitors and development of a flare minimization plan, neither of which the public will have a chance to review and comment. Moreover, the permit fails to provide that the flare minimization plan be submitted to the Department for approval.

10.2 **Ambient Air Monitoring**. The Permittee shall establish ambient PM-10 and PM-2.5 monitoring during the construction phase as follows: a. At least 180 days prior to commencing construction, submit for Department approval a scaled site map(s) that identifies the proposed locations of one or more downwind PM-10 monitoring site and one or more downwind PM-2.5 monitoring site.4 Site the monitoring stations in areas that would likely experience the maximum construction-related 24-hour PM-10 and 24-hour PM-2.5 impacts from the Liquefaction plant project area. Include a written narrative that documents the reasons for selecting the proposed monitoring sites.[49]

17. **Vent Gas Disposal (Flares) BACT Emission Limits:** Limit the emissions from flares EUs 14 through 19 as specified in Table 7 and from EU 20 as specified in Table 8, which indicate that BACT control for these units is "*proper flare work practice requirements and establishing a flaring minimization plan.*"[50]"

Department Response: The Department revised Condition 10.2 to require one or more upwind PM-10 and PM-2.5 monitoring sites to ensure that monitoring is conducted adequately both upwind and downwind for ***both*** *PM-10 and PM-2.5 (emphasis added). Additionally, Condition 10.2b requires AGDC to submit a Quality Assurance Project Plan (QAPP) to the Department for approval for the PM-10/PM-2.5 monitoring effort with 60 days of the Department's approval of the monitoring locations. The Department finds this to be adequate to ensure that the monitors are appropriately sited during the construction phase to monitor fugitive dust. The Department notes that the public does not have an opportunity to comment on the appropriateness of monitor siting during pre-application monitoring if on-site monitoring is utilized in lieu of modeling, but that the Department's monitoring QAPP will ensure proper monitor siting to ensure continued compliance with ambient air quality standards.*

There will also be a manual or automated system that continuously reviews the PM-10 and PM-2.5 monitoring data and requirements to act if measured concentrations exceed the respective thresholds in Condition 10.2d to ensure continued compliance with the ambient air quality standards. The hourly PM-10 and PM-2.5 concentrations will be uploaded to a publicly accessible database daily.

[49] Draft permit at 8-9.
[50] Draft permit at 23-24. (emphasis added)

The Department notes that Condition 17 has been revised and the flare minimization plan is now included in Section 11 of the permit.

16. Marine Terminal

16.1. Chickaloon Commented – A marine terminal will be constructed. When will the permits for this construction activity come out, unrelated to air permits?"

Department Response: Permits for construction activity of the marine terminal that are unrelated to air permits are outside of the scope of this air permitting action. Any permitting that is outside of the scope for the Liquefaction Plant will be addressed at the time that various agencies receive their respective applications.

Attachment A
NPCA Comments

December 10, 2020

Via Electronic Mail

Dave Jones
ADEC
P.O. Box 111800
Juneau, AK 99811
dave.jones2@alaska.gov

Re: National Parks Conservation Association, Center for Biological Diversity, and Northern Alaska Environmental Center Comments on Preliminary Prevention of Significant Deterioration Permit No. AQ1539CPT01, Proposed in response to Application from Alaska Gasline Development Corporation to Construct a Liquefaction Plant in Nikiski, Alaska

Dear Mr. Jones,

Please find enclosed the comments submitted on draft Construction Permit No. AQ1539CPT01, in regards to the application from Alaska Gasline Development Corporation to construct a Liquefaction Plant in Nikiski, Alaska, on behalf of National Parks Conservation Association, Center for Biological Diversity, and Northern Alaska Environmental Center. The enclosures were submitted at the website you provided earlier for this purpose: https://drop.state.ak.us/drop/. The list of enclosure is attached to these comments.

We appreciate the Department's consideration of these comments. Please do not hesitate to contact me with any questions.

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Sincerely,

Sara L. Laumann
Principal
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cc: Stephanie Kodish, NPCA
Jim Adams, NPCA
Liz Jones, Center for Biological Diversity
Kristen Monsell, Center for Biological Diversity
Lisa Baraff, Northern Alaska Environmental Center
Krishna Viswanathan, EPA
Amy Johansen, EPA
Doug Hardesty, EPA

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I. Introduction

NPCA is a nonprofit and nonpartisan organization working to protect and enhance America's National Park System for present and future generations. The National Parks Conservation Association was founded in 1919, and today has more than 1.3 million members and supporters. It is headquartered in Washington, D.C., and has various regional and field offices, including an Alaska Regional office in Anchorage. Among other things, it works to ensure that national parks and the air, waters and wildlife that moves through them are protected.

The Center for Biological Diversity is a national, nonprofit organization with more than 1.7 million members and online activists. The Center works through science, law, and advocacy to secure a future for all species, great and small, hovering on the brink of extinction, with a focus on protecting the lands, waters, and climate that species need to survive.

The Northern Alaska Environmental Center (Northern Center), founded in 1971, is a small nonprofit organization dedicated to the conservation of the environment and sustainable resource stewardship in Interior and Arctic Alaska through education and advocacy. Based in Fairbanks, Alaska, the Northern Center has over 900 members and more than 4000 supporters online. Since its inception, the Northern Center has been the only local nonprofit environmental conservation organization dedicated to protecting the Arctic.

On September 11, 2020, the Alaska Department of Environmental Conservation (ADEC) proposed approval of a Clean Air Act Prevention of Significant Deterioration (PSD) permit to the Alaska Gasline Development Corporation (AGDC), which would allow construction of a Liquefaction plant in Nikiski, Alaska that would cool, process, store, and load liquefied natural gas (LNG) for shipment of Alaska's North Slope natural gas to outside markets. ADEC also classified the plant as a major source of Hazardous Air Pollutants for formaldehyde and ethylbenzene.

NPCA prepared these comments in coordination with the reports prepared by Mr. Howard Gebhart[1] and Ms. Victoria Stamper.[2] Mr. Gebhart is an air quality meteorologist with 40 years of experience in air quality permitting, specializing in air dispersion modeling. Ms. Stamper is an independent air quality consultant with over 30 years of experience in the field of air pollution control and extensive experience in new source review permitting. The comments in these two reports are incorporated by reference as a part of these comments.

II. Regulatory Framework and Background

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[1] *See* enclosed report entitled "Technical Comments on Alaska LNG Project - Liquefaction plant PSD Permit," (Dec. 6, 2020) ("Gebhart Report"), prepared by Mr. Howard Gebhart. Mr. Gebhart's Curriculum Vitae is enclosed.
[2] *See* enclosed report entitled "Comments on the Best Available Control Technology (BACT) Analysis of the Alaska Department of Environmental Conservation's Proposed Air Quality Construction Permit for the Alaska Gasline Development Corporation Liquefaction Plant to be Located in Nikiski, Alaska," (Dec. 8, 2020) (Stamper Report), prepared by Victoria Stamper. Ms. Stamper's Curriculum Vitae is in Attachment A to that report.

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The Clean Air Act (CAA) aims to "protect and enhance the quality of the Nation's air resources."[3] To this end, the Act employs a variety of programs—including the Prevention of Significant Deterioration (PSD) program, which governs air pollution in areas where the air quality meets or is cleaner than the National Ambient Air Quality Standards (NAAQS).[4] The PSD provisions were added to the CAA in 1977 to focus on "facilities which, due to their size, are financially able to bear . . . substantial regulatory costs . . . and which, as a group, are primarily responsible for emissions of the deleterious pollutants that befoul our nation's air."[5] Under the PSD program, owners or operators of major emitting facilities in attainment or unclassifiable areas must obtain a PSD permit prior to the construction of that facility.[6] The ultimate purpose of the PSD program is to maintain air quality better than the NAAQS and Congress repeatedly emphasized that NAAQS alone were insufficient to protect public health and welfare.[7] For example, the

> Senate Report emphasized the 'shortcomings and limitations' of the ambient standards—they do not provide an adequate margin of safety on health impacts; they are based on a false assumption that no-effects threshold levels exist; they do not adequately protect against genetic mutations, birth defects, cancer, or diseases caused by long-term chronic exposures or periodic short-term peak concentrations, and hazards due to derivative pollutants and to cumulative or synergistic impacts of various pollutants; and they do not adequately protect against crop damage and acid rain.[8]

Congress designed the Prevention of Significant Deterioration program with the goal of "assur[ing] that any decision to permit increased air pollution . . . is made *only after careful evaluation of all the consequences of such a decision*."[9] The PSD program prohibits the construction of any "major emitting facility" unless it obtains a pre-construction permit ensuring that the project is subject to the best available control technology (BACT) for each regulated pollutant;[10] that the project will not cause or contribute to a violation of either NAAQS or so-called PSD "increments" approaching the NAAQS; and that the project will satisfy all other applicable requirements of the Act.[11] Determination of BACT is made "on a case-by-case basis,

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[3] 42 U.S.C. § 7401.
[4] 42 U.S.C. § 7470.
[5] *Ala. Power Co. v. Costle*, 636 F.2d 323, 353 (D.C. Cir. 1980)("Alabama Power").
[6] 42 U.S.C. §7475.
[7] *Hawaiian Elec. Co. v. U.S. E.P.A.*, 723 F.2d 1440, 1446-7 (9th Cir. 1984)("Hawaiian Elec.").
[8] *Id.*, citing, H.R. Rep. No. 294, 95th Cong., 1st Sess. 105–132, *reprinted in* 1977 U.S. Code Cong. & Ad. News 1183–1211; *see also* Statement by Senator Muskie in *A Legislative History of the Clean Air Act Amendments of 1977,* 95th Cong., 2d Sess. No. 16 (1979), vol. 3, pp. 1032–1035. "The non-degradation amendment is intended to help reduce overall emissions and thus provide protection against these kinds of adverse impacts." *Legislative History, supra,* at 728.
[9] 42 U.S.C. § 7470 (emphasis added). In furtherance of that goal, EPA permitting guidance requires state agencies to make independent determinations about necessary emissions controls and not to rely solely on applicant information. EPA, New Source Review Workshop Manual, at B.53-54 (Draft Oct. 1990) ("NSR Workshop Manual"), available at https://www.epa.gov/sites/production/files/2015-07/documents/1990wman.pdf (last visited. Nov. 30, 2020).
[10] All new source applicants must install the "best available control technology" ("BACT") to reduce air pollution. *Id.* § 7475(a)(4). Determination of the best available control technology is made "on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs." *Id.* § 7479(3). *Citizens for Clean Air v. U.S. E.P.A.*, 959 F.2d 839, 842 (9th Cir. 1992)("Citizens").
[11] 42 U.S.C. § 7475.

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taking into account energy, environmental, and economic impacts and other costs."[12] "The BACT requirement consists of 'an emission limitation based on the maximum degree of reduction of each [regulated] pollutant' that EPA [or a state] determines is achievable 'through application of production processes and available methods, systems, and techniques' in view of 'energy, environmental, and economic impacts and other costs.'"[13]

Congress found that it was important to reduce pollution levels below those mandated by the standards and that the best means of doing so was to require the installation of BACT on all sources which would otherwise increase pollution.[14]

In addition to the BACT analysis, a new source seeking a PSD permit must also complete an air quality analysis. The purpose of this analysis is to ensure that the emissions from the proposed facility, in conjunction with the emissions from other sources, will not cause or contribute to a violation of the national ambient air quality standards or the PSD increment limits. The national air standards place a ceiling on the total concentration of certain pollutants in the atmosphere. The PSD increments, on the other hand, place a limitation on the amount a source may increase the concentration of a pollutant over the baseline. The amount of increase allowed varies based on the location of the proposed source. Locations are divided into three categories. Class I allows the smallest increase in pollution levels and covers specific national parks, wilderness areas and Tribal lands. Class II allows a moderate increase and applies to areas considered normal growth areas. Class III areas can have the largest increment and are areas where the state or local authority foresees a greater amount of industrial development, there are no Class III areas. States must model the air quality impacts of a proposed new source of air pollution according to federal regulations before they can issue a permit to that source. These regulations require that a state model the air quality impacts of a new source using meteorological data that is "representative" of the proposed source site.[15] The meteorological data is used to predict how emissions will behave once emitted from a source. A state also must model all emissions at the levels allowed in the proposed permit,[16] along with other model and emission requirements specified in the state's rules, which are approved by EPA for this purpose.

States can seek federal approval to administer the PSD permit program through a "State Implementation Plan," or SIP. To gain EPA approval, a SIP must "include enforceable emission limitations and other control measures, means, or techniques . . . as may be necessary or appropriate to meet the applicable [Clean Air Act] requirements" and to "assure that national ambient air quality standards are achieved."[17] SIPs also must "contain emission limitations and such other measures as may be necessary . . . to prevent significant deterioration of air quality."[18] While EPA approves state programs, it retains oversight authority over implementation by a state.[19]

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[12] *Id.* § 7479(3).
[13] 42 U.S.C. § 7479(3); *Sierra Club v. U.S. E.P.A.*, 762 F.3d 971, 974 (9th Cir. 2014).
[14] *Hawaiian Elec.* at 1447.
[15] 40 C.F.R. Pt. 51, App. W at 8.4.1(b) ("EPA Guideline on Air Quality Models").
[16] *Id.* at Table 8-2.
[17] 42 U.S.C. § 7410(a)(2).
[18] 42 U.S.C. § 7471; *see also* 40 C.F.R. §§ 51.166, 52.21.
[19] *Alaska Dep't of Envtl. Conservation v. E.P.A.*, 540 U.S. 461 (2004) (affirming EPA's reversal of a state permitting decision) ("ADEC").

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Alaska administers the PSD program through an EPA-approved SIP.[20] Like its federal counterpart, Alaska's PSD program requires would-be permittees to analyze all potential impact of their proposal on air quality, visibility, soils, and vegetation. It also adopts the five-step "top down" BACT analysis propounded by the EPA, further developed by its Environmental Appeals Board,[21] and upheld by the federal courts.[22] The ADEC's Preliminary "Technical Analysis Report" for the terms and conditions of proposed Construction Permit AQ1539CPT01 explains that "[t]he Department based the BACT review on the five-step top-down approach set forth in" EPA's 1996 Federal Register notice.[23] EPA's 1996, notice explained that "[s]ince late 1987 EPA has recommended a specific process for determining BACT."[24] Specifically, "[t]he EPA's recommended methodology for determining BACT is described in detail in the 1990 Draft NSR Workshop Manual."[25] The five-step top-down process includes:

Figure 1. The Clean Air Act's BACT Five-Step Process.[26]

Step 1: Identify All Control Technologies.[27]	A comprehensive list of control technologies must be identified, including technologies required under lowest achievable emission rate determinations.
Step 2: Eliminate Technically Infeasible Options.	A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.
Step 3: Rank Remaining Control Technologies by	Should include: • control effectiveness (percent pollutant removed); • expected emission rate (tons per year); • expected emission reduction (tons per year);

[20] When EPA approves a state SIP, it incorporates the relevant state law into the Code of Federal Regulations by reference. ADEC's EPA-approved PSD SIP program has been revised over the years, and in addition to some provisions that occur in ADEC regulations and State statute, ADEC's SIP includes EPA PSD regulations that were adopted by reference in the State's rules and State statute. Furthermore, ADEC and the State legislature adopted portions of EPA's PSD regulations on different years.

[21] The EPA's Environmental Appeals Board adjudicates appeals from federally-issued PSD permits (as well as state permits issued under federal delegation) and has developed a body of case law on BACT requirements. Because state PSD programs must "implement standards and limitations as stringent as those set by the EPA" and must be interpreted "with an eye to furthering the goals of the [federal] PSD program," agencies and courts turn to the Board's rulings in applying their respective state PSD programs. *Utah Chapter of the Sierra Club v. Air Quality Board*, 226 P.3d 719, 727, 733 (Utah 2009). In sum, a permitting authority is required to follow the EPA's analytical permitting framework unless it has clearly articulated (and provided a statutory foundation for) its own alternative. *Cash Creek Generation LLC*, Petition No. IV-2008-1, 9 (Dec. 15, 2009), available at https://www.epa.gov/sites/production/files/2015-08/documents/cashcreek_response2008.pdf ("Cash Creek I").

[22] *See generally Sierra Club v. Environmental Protection Agency*, 499 F.3d 653 (7th Cir. 2007).

[23] ADEC, "Preliminary Technical Analysis Report For the terms and conditions of Construction Permit AQ1539CPT01," at 1 (Sept. 11, 2020) ("PreTAR"); 61 Fed. Reg. 38250 (July 23, 1996).

[24] *Id.* at 38272.

[25] NSR Workshop Manual, at B.53-54.

[26] *Id.* at B-6.

[27] Control technologies "are those technologies that have 'a practical potential for application to the emissions unit and the regulated pollutant under evaluation.'" *Helping Hand Tools v. U.S. Envtl. Prot. Agency*, 848 F.3d 1185, 1190 (9th Cir. 2016)("Helping Hand") (quoting, NSR Workshop Manual, at B.5). Generally, under federal law the failure to consider available alternative control technologies (also referred to as "control alternatives") in BACT analysis "constitutes clear error." *Id.* at 1194.

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Control Effectiveness.	• energy impacts (BTU, kWh); • environmental impacts (other media and the emissions of toxic and hazardous air emissions); and • economic impacts (total cost effectiveness, incremental cost effectiveness).
Step 4: Evaluate Most Effective Controls and Document Results.	Case-by-case consideration of energy, environmental, and economic impacts. If top option is not selected as BACT, evaluate next most effective control option.
Step 5: Select BACT.	Most effective option not rejected is BACT.

Failing to conduct a complete BACT analysis, including failure to consider all potentially applicable control alternatives, is an abuse of the permitting authority's discretion.[28] A state is only authorized to issue permits to sources that "will not cause, or contribute to, air pollution in excess of any . . . maximum allowable increase or maximum allowable concentration for any pollutant" or any National Ambient Air Quality Standard.[29]

Additionally, another feature of the PSD program is that all "new sources must meet 'New Source Performance Standards,' which impose various emissions limitations."[30] "EPA periodically promulgates New Source Performance Standards under its rulemaking authority."[31] Finally, regulations for the PSD program require notice, a comment period, and a public hearing on applications for new sources of air pollution.

One of the stated purposes of the PSD program is "to preserve, protect, and enhance the air quality in national parks [and] national wilderness areas."[32] There are 156 federally designated Class I area national parks and wilderness areas under Act,[33] that are entitled to additional protection under the PSD program.[34] The U.S. Fish and Wildlife Service (USFWS) and the National Park Service (NPS) are the Federal Land Managers (FLMs) charged with direct responsibility to protect the air quality and related values (including visibility) of Alaska's Class I areas and Class II nationally designated protected areas. FLMs have an affirmative obligation to consider, in consultation with the EPA [and the permitting authority], whether proposed industrial facilities would have an adverse impact on these values.[35] Moreover, the Mission of the USFWS Air Quality Program is to "[p]rotect and enhance air quality in support of ecosystem management in the National Wildlife Refuge System, in an effort to create a Refuge System free of impacts from human-caused air pollution and promote biological integrity, diversity, and

[28] *See Louisville Gas & Electric Co.*, 2009 WL 7698409, 13 (EPA 2009) (citing *Prairie State Generation*, 13 E.A.D. ___, PSD Appeal No. 05-05, slip op. at 19 (EPA 2006); *Knauf Fiber Glass*, 8 E.A.D. 121, 142 (EPA 1999)("Knauf I"); *Masonite Corp.*, 5 E.A.D. 551, 568-569 (E.A.B. 1994)("Masonite").
[29] 42 U.S.C. § 7475(a)(3).
[30] *Citizens* at 842, *Id.* § 7411(a), (f).
[31] *Id. § 7411(b)(1)(B).*
[32] 42 U.S.C. § 7470(2).
[33] 42 U.S.C. § 7472(a).
[34] A number of Tribal lands have been redesignated as Class I areas, although these newer designations are not considered "federally mandated."
[35] 42 U.S.C. § 7475(c).

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environmental health of the system."[36] The NPS' Air Resource Division, "together with parks and other National Park Service offices, monitors air quality conditions in parks and conducts research to better understand the sources and effects of air pollution. Additionally, because most pollution in national parks comes from outside park boundaries, the Air Resources Division facilitates NPS partnerships with air regulators, industries, and other stakeholders to reduce air pollution. Less pollution means cleaner air, clearer views and healthier ecosystems for parks and nearby communities."[37]

The USFWS has direct responsibility for managing wilderness and refuges, under its CAA responsibilities and the specific protections afforded these special places by Congress. The Tuxedni Wilderness[38] within the Alaska Maritime National Wildlife Refuge (NWR) is designated a Class I area, and the Arctic, Kanuti, Yukon Flats, Koyukuk, Selawik, Nowitna, Kenai, Kodiak, and Alaska Maritime NWRs are Class II sensitive areas.[39] The USFWS is responsible for land management within all of these NWRs, a portion of which would be within 186.4 miles of the AGDC's proposed facilities.[40]

The NPS manages its lands to protect and preserve natural and cultural resources unimpaired for the enjoyment of future generations. The NPS is responsible for management of lands within the Denali National Park and Preserve (DNPP), Lake Clark National Park and Preserve (NPP), Kenai Fjords National Park, and Gates of the Arctic NPP, all of which would be

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[36] USFWS, "Mission of the U.S. Fish and Wildlife Service Air Quality Program," available at https://www.fws.gov/refuges/AirQuality/index.html, which involves "[p]rotecting air quality, and resources sensitive to air quality, in the National Wildlife Refuge System is a complex task that includes: active research and monitoring about the amount and effects of pollution in FWS areas; advocacy for pollution controls when they are likely to affect FWS refuge areas; and ensuring there is an active advocate of clean healthy air across the National Wildlife Refuge System." *Id.*

[37] NPS, Air Resource Division, "What We Do," available at https://www.nps.gov/orgs/1971/whatwedo.htm.

[38] USFWS, The Tuxedni Wilderness, Alaska Maritime National Wildlife Refuge (NWR) – Tuxedni Wilderness (Refuge area and Class I Designation), available at https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/.

[39] USFWS, Air Quality in Refuges, https://www.fws.gov/refuges/AirQuality/ARIS.html.
(The Air Quality in Refuges pages provide information on refuges and wilderness areas managed by the U.S. Fish and Wildlife Service (FWS) as well as Inventory & Monitoring (I & M) networks. Air Quality in Refuges pages identifies air quality related values for Class I air quality areas and provides guidance on analysis for evaluating impacts to air quality related values. These Air Quality in Refuge pages maintains information on 21 FWS Class I areas and other FWS Class II sensitive areas.)

[40] Per the Alaska National Interest Lands Conservation Act (ANILCA) 303(1)(B), the purposes for which the Alaska Maritime NWR, including Tuxedni NWR [ANILCA 303(1)(v) Gulf of Alaska (GOA) Unit], Arctic NWR (ANWR) [ANILCA 303(2)(B)]; Kanuti NWR [ANILCA 302(4)(B)]; Kenai NWR [ANILCA 303(4)(B)]; Kodiak NWR [ANILCA 303(5)(B)]; Koyukuk NWR [ANILCA 302(5)(B)]; Nowitna NWR [ANILCA 302(6)(B)]; Selawik NWR [ANILCA 302(7)(B)]; and, Yukon Flats NWR [ANILCA 302(9)(B) and 303(7)(B)] were established and managed are to: conserve fish and wildlife populations and habitats in their natural diversity; fulfill the international treaty obligations of the United States with respect to fish and wildlife and their habitats; provide the opportunity for continued subsistence uses by local residents; provide a program of national and international scientific research on marine resources; and ensure, to the maximum extent practicable, water quality and necessary water quality within the refuge. These purposes are integrated into Comprehensive Conservation Plans applicable to each refuge. In addition to ANILCA, each refuge is administered under the National Wildlife Refuge System Administration Act of 1966, as amended by the National Wildlife Refuge System Improvement Act of 1997 (16 U.S.C. §§ 668dd-668ee), which serves as the "organic act" for the National Wildlife Refuge System. The National Wildlife Refuge System Improvement Act provides a foundation for the USFWS' biological integrity, diversity, and environmental health policy. Finally, many refuges in Alaska have portions that are congressionally designated as wilderness or possess wilderness characteristics under the Wilderness Act of 1964.

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within 186.4 miles of Project facilities. The DNPP is designated a Class I area, while Lake Clark, Kenai Fjords, and Gates of the Arctic are designated as Class II nationally designated protected areas.

The NPS and USFWS describe the following *existing*, adverse impacts on visibility and AQRVs, as well as sensitive ozone species[41] at some of these impacted parks, preserves and wilderness areas as follows:

- **Lake Clark National Park and Preserve**. Lake Clark National Park and Preserve protects approximately 4 million acres of undisturbed public land characterized by scenic vistas such as; rugged mountain peaks and spires, glaciers, an ocean coast, deep valleys and lakes, high tundra, wild rivers, and a wide cross-section of flora and fauna. Most visitors to the park and preserve experience scenic vistas by flying in by small airplane and either hiking, boating, fishing, or camping in the area. Scenic vistas are for the most part intact, but are threatened by development activities outside of the park. Pollutant haze may obscure visibility at the wilderness area part of the time.[42] Additionally, Although Lake Clark is mostly uninhabited wilderness concern has been growing about air quality in areas of Lake Clark National Park and Preserve, particularly along the coast.[43]

- **Tuxedni National Wildlife Refuge.**[44] Designated a Class I area in 1977, this area consists of "[t]wo islands at the mouth of Tuxedni Bay (Chisik and Duck) were established as a refuge for seabirds, bald eagles and peregrine falcons in 1909, as shown in green in the map to the right. … Other species protected in this Wilderness Area include large colonies of sea birds, black-legged kittiwakes, horned puffins, common murres, pigeon guillemots, and glaucous-winged gulls. Other species include several endangered or threatened species such as short tailed albatross, Eskimo curlew, leatherback sea turtle, Steller western and eastern pop. Sea-lion, bowhead whale, humpback whale, spectacled eider, Steller's AK breeding populations, lynx, and otter."[45] Potential air pollution threats to Tuxedni include oil and gas development in Alaska, especially in the Cook Inlet,[46] Human

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[41] Ozone Sensitive Species: The NPS maintains a compilation of ozone sensitive species. Its compilation shows there are numerous ozone sensitive species at several of these special areas, including: LACL; KEFJ; DNPP; GAAR; and KEFJ. NPS, "Ozone Sensitive Species by Park," available at https://irma.nps.gov/NPSpecies/Reports/Systemwide/Ozone-sensitive%20Species%20by%20Park. (enclosed)

[42] NPS, Lake Clark NPP, Environmental Factors, available at https://www.nps.gov/lacl/learn/nature/environmentalfactors.htm.

[43] *Id.*

[44] There is an IMPROVE sampler at the Refuge. *See Interagency Monitoring of Protected Visual Environments,* IMPROVE Program Overview, *available at http://vista.cira.colostate.edu/Improve/improve-program/* (enclosed).

[45] USFWS, Tuxedni Wilderness, available at https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/.

[46] *Id.* (Discussing the Tuxedni NWR adjacent to Lake Clark); *see also* USFWS Air Quality Alaska Maritime National Wildlife Refuge (NWR) - Tuxedni Wilderness, available at https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/AirQuality.html; USFWS AQRVs Alaska Maritime National Wildlife Refuge (NWR) - Tuxedni Wilderness, available at https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/AQRV.html; USFWS Air Pollution Impacts (Visibility) Alaska Maritime National Wildlife Refuge (NWR) - Tuxedni Wilderness available at

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produced haze occasionally impairs scenic vistas at the refuge.[47] This degradation results in the reduction of the average natural visual range from about 150 miles (without the effects of pollution) to about 125 miles (with the effects of pollution) at the refuge. On the most polluted days the average visual range has been reduced to 68 miles on the most polluted days (20% highest pollution days). The U.S. Fish and Wildlife Service has begun monitoring air quality in the Refuge in cooperation with the National Park Service and the State of Alaska.[48] "If the Tuxedni Wilderness is not protected, unique wildlife and scenic values could be threatened or lost. The FWS hopes to preserve and protect this special area of wilderness for future generations."[49]

- **Denali National Park and Preserve**. The Park and Preserve include more than 6 million acres, which in 2019 had more than 600,000 visitors.[50] Many of its visitors travel the 92-miles road, which parallels the Alaska Range and travels through low valleys and high mountain passes. It is the only road in the park. Along its route, beautiful landscapes can be seen at every turn, and there are many opportunities to view Denali.[51] Pollution reduces the average natural visual range from about 165 miles (without the effects of pollution) to about 160 miles at the park. Reduction of the visual range to below 105 miles is experienced on very hazy days.[52] DNPP is also particularly susceptible to the accumulation of persistent organic pollutants (POPs) and other toxic airborne contaminants. Episodes of high ozone concentrations have been documented in the park, but thus far, these episodes are relatively short in duration.[53] Further, while ozone effects have not been documented in the park, several park species, including *Salix scouleriana* (Scouler's willow) and *Populus tremuloides* (quaking aspen), are known to be sensitive to ozone.[54] The risk from either acidification or fertilization is considered low at DNPP because rates of nitrogen and sulfur deposition are very low.[55] However, certain vegetation communities in the park, including wetlands and arctic vegetation, are known to be vulnerable to excess nitrogen deposition.[56] If nitrogen deposition increases significantly, these plant communities could be affected. Certain lichen species that occur in the park are

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https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/Impacts.html; USFWS Air Pollution Impacts (Nitrogen & Sulfur) Alaska Maritime National Wildlife Refuge (NWR) - Tuxedni Wilderness available at https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/Impacts.html; USFWS Air Pollution Impacts (Ozone) Alaska Maritime National Wildlife Refuge (NWR) – Tuxedni Wilderness available at https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/Impacts.html; USFWS Monitoring Alaska Maritime National Wildlife Refuge (NWR) – Tuxedni Wilderness available at https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/Monitoring.html.

[47] *Id.*

[48] *Id.*

[49] USFWS, Tuxedni Wilderness, available at https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/.

[50] NPS, Denali, Park Statistics, available at https://www.nps.gov/dena/learn/management/statistics.htm.

[51] NPS, Introduction to Denali, available at https://www.nps.gov/dena/planyourvisit/visiting-denali.htm.

[52] NPS, Park Air Profiles, Denali National Park & Preserve, available at https://www.nps.gov/articles/airprofiles-dena.htm.

[53] *Id.*

[54] *Id.*

[55] *Id.*

[56] *Id.*

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known to be sensitive to air pollution, including the globally rare *Erioderma pedicellatum*.[57]

Moreover, in light of "potential nitrogen deposition impact concerns in Denali National Park" including "potential declines in lichen communities in the south end of the park that are an important component of park ecosystems, as well as potential impacts to a globally rare lichen species that is listed as critically endangered by the International Union for Conservation of Nature (IUCN)," the NPS recommended that SCR controls for NOx BACT may be economically feasible and is necessary to address potential nitrogen deposition impact concerns in Denali National Park.[58]

- **Kenai Fjords National Park and Lake Clark National Park and Preserve.** NPS published a report in 2016,[59] which identified several concerns regarding AQRVs at this two areas. For example, in assessing nutrient nitrogen enrichment, the study explained that "[e]ctomycorrhizal fungal (EMF) communities are important in tree nutrition, and EMF trees tend to be dominant in N-limited forest ecosystems."[60] The report further explained that earlier studies found "[p]rogressive decline in EMF species richness in Alaskan coniferous forest (white spruce [*Picea glauca*] dominant) occurred along a local N deposition gradient, from 1 to 20 kg N/ha/yr, downwind from a fertilizer facility," which is

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[57] *Id. See also,* Nelson, P., Walton, J. and Roland, C. "Erioderma pedicellatum (Hue) P. M. Jorg., New to the United States and Western North America, Discovered in Denali National Park and Preserve and Denali State Park, Alaska," Evansia 25: 19–23 (2009), available at https://www.researchgate.net/publication/259742473_Erioderma_pedicellatum_Hue_PM_Jorg_New_to_the_United_States_and_Western_North_America_Discovered_in_Denali_National_Park_and_Preserve_and_Denali_State_Park_Alaska/link/0deec52d89f551f5c8000000/download.

[58] NPS Email to ADEC (Dec. 4, 2020) (included as an enclosure to these comments). The NPS further explains that "[t]his species was only recently discovered at several sites within and near Denali NP. These populations are the only known occurrences within the US and western North America." *Id.*

[59] Sullivan, T. J., "Air quality related values (AQRVs) for Southwest Alaska Network (SWAN) parks: Effects from ozone; visibility reducing particles; and atmospheric deposition of acids, nutrients and toxics," Natural Resource Report NPS/SWAN/NRR—2016/1204 (2016). National Park Service, Fort Collins, Colorado, available at https://irma.nps.gov/DataStore/DownloadFile/548903 (Sullivan). *See also* Flanagan, C., "Contaminants study provides window onto airborne toxic impacts in western U.S. and Alaska national parks. Results and implications of the Western Airborne contaminants Assessment Project," Park Science 26(2):58-63 (2009), available at https://irma.nps.gov/DataStore/Reference/Profile/2201538; Flanagan Pritz, C.M., J.E. Schrlau, S.L. Massey Simonich, and T.F. Blett, "Contaminants of emerging concern in fish from western U.S. and Alaskan National Parks — spatial distribution and health thresholds," J. Am. Water Resour. Assoc. 50(2):309-323 (2014), available at https://onlinelibrary.wiley.com/doi/epdf/10.1111/jawr.12168 (included as an enclosure with these comments); Mölders, N., S.E. Porter, C.F. Cahill, and G.A. Grell, "Influence of ship emissions on air quality and input of contaminants in southern Alaska National Parks and Wilderness Areas during the 2006 tourist season," Atmos. Environ. 44(11):1400-1413 (2010), available at https://www.sciencedirect.com/science/article/abs/pii/S1352231010001044?via%3Dihub (included as an enclosure with these comments); Munk, L., B. Cohn, and B. Finney, "Historical Trace Element Trends Recorded in Lake Sediment Cores from the Southwest Alaska Network of Parks. Natural Resources Technical Report," NPS/SWAN/NRTR-2010/395 (2010). National Park Service, Fort Collins, CO, available at https://www.sciencedirect.com/science/article/abs/pii/S1352231010001044?via%3Dihub (included as an enclosure with these comments).

[60] *Id.* at 9.

nearby the proposed Liquefaction Plant, that was shut down at the time of the study, and is located on the Kenai Peninsula west of KEFJ."[61] (Lilleskov et al. 2001, Lilleskov et al. 2002). Additionally, regarding ozone injury to vegetation, KEFJ contains "quaking aspen (*Populus tremuloides*), thought to be among the most sensitive hardwood tree species to O3 damage."[62] LACL also contains two species sensitive to O3 damage: FILL IN.[63] Furthermore, LACL is impacted by "inland transport of pollutants from ship traffic," which is enhanced by "the channeling of east winds between the Kenai Peninsula and Kodiak Island… ."[64] Ecosystem ranking of acidification at LACL ranked "Very High," indicating a sensitivity to acidification.[65] LACL is located about 30 miles from the Tuxedni Wilderness, which is "monitored by the Interagency Monitoring of Protected Visual Environments Network (IMPROVE)."[66] Thus that "monitoring site is considered by IMPROVE to be representative of" LACL because it is an area "within 60 mi (100 km) and 425 ft (130 m) in elevation of" Tuxedni.[67] Therefore, the threats and degradation at Tuxedni described above are also present at LACL. Furthermore, a study that measured airborne Synthetic Organic Carbon contaminant concentrations in fish collected from lakes in LACL, "thresholds to protect kingfisher were exceeded in some fish from some lakes for chlordane and P,P'-DDE."[68] Additionally, mercury concentrations in fish from LACL's " Lake Kontrashibuna and Lake Clark" were found to exceeding the benchmark for

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[61] *Id., citing* Lilleskov, E.A., T.J. Fahey, and G.M. Lovett, "Ectomycorrhizal fungal aboveground community change over an atmospheric nitrogen deposition gradient," Ecol. Appl. 11(2):397-410 (2001), available at https://doi.org/10.1890/1051-0761(2001)011[0397:EFACCO]2.0.CO;2, (included as an enclosure with these comments); Lilleskov, E.A., T.J. Fahey, T.R. Horton, and G.M. Lovett, "Belowground ectomycorrhizal fungal community change over a nitrogen deposition gradient in Alaska," Ecology 83(1):104-115 (2002), available at https://doi.org/10.1890/0012-9658(2002)083[0104:BEFCCO]2.0.CO;2, included as an enclosure with these comments, checking to see if NPCA can obtain. Although the fertilizer facility was shutdown at the time of the study, ADEC is in the process of reviewing a PSD application submitted by Agrium U.S. Inc. for their Kenai Nitrogen Operations (KNO) Facility. There are two ammonia and two urea plants at Agrium's KNO facility and ADEC's proposed permit would authorize the restart of one ammonia and one urea plant. ADEC's recently proposed PSD permit documents are included as enclosures with these comments. Finally, ADEC's January 6, 2016, Technical Analysis Report, which is the only document for Liquefaction Plant available on ADEC's website is also included as an enclosure with these comments).

[62] Sullivan at 12.

[63] NPS, "Ozone Sensitive Species by Park," available at https://irma.nps.gov/NPSpecies/Reports/Systemwide/Ozone-sensitive%20Species%20by%20Park.

[64] *Id.* at 3.

[65] *Id.* at 4. The study examined information available in 2006, and noted at that time "[a]lthough aquatic and/or terrestrial resources in some SWAN [Southwest Alaska Network] parks may indeed be sensitive to acidification, this is not an important concern at this time in view of the very low levels of S and N emissions and deposition within and near this network." These impacts could change with the proposed approval of the fertilizer facility, *supra* n.54.

[66] *Id.* at 13.

[67] *Id.*

[68] *Id.* at 19, *citing* Simonich, S.L.M., J. Schrlau, C. Flanagan, and T. Blett, "Chemical Burdens in Fish from Alaskan Parks Compared to Human and Wildlife Health Consumption Thresholds" (2013), available at http://depts.washington.edu/pnwcesu/reports/J8W07100027_Final_Report.pdf. Additionally, Sullivan explain "fisheries biologists have been collecting and analyzing fish tissue samples from selected lakes in LACL and KATM. Analyses include Hg, arsenic, copper, selenium, lead, and zinc every 5 years and for certain POPs every 10-15 years. Baseline sampling was conducted in 2011 for lake trout, northern pike (*Esox lucius*), and slimy sculpin (*Cottus cognatus*); Data collected on future sampling occasions will shed light on potential trends in bioaccumulation of toxics in aquatic receptors." *Id.* at 33 (internal citations omitted).

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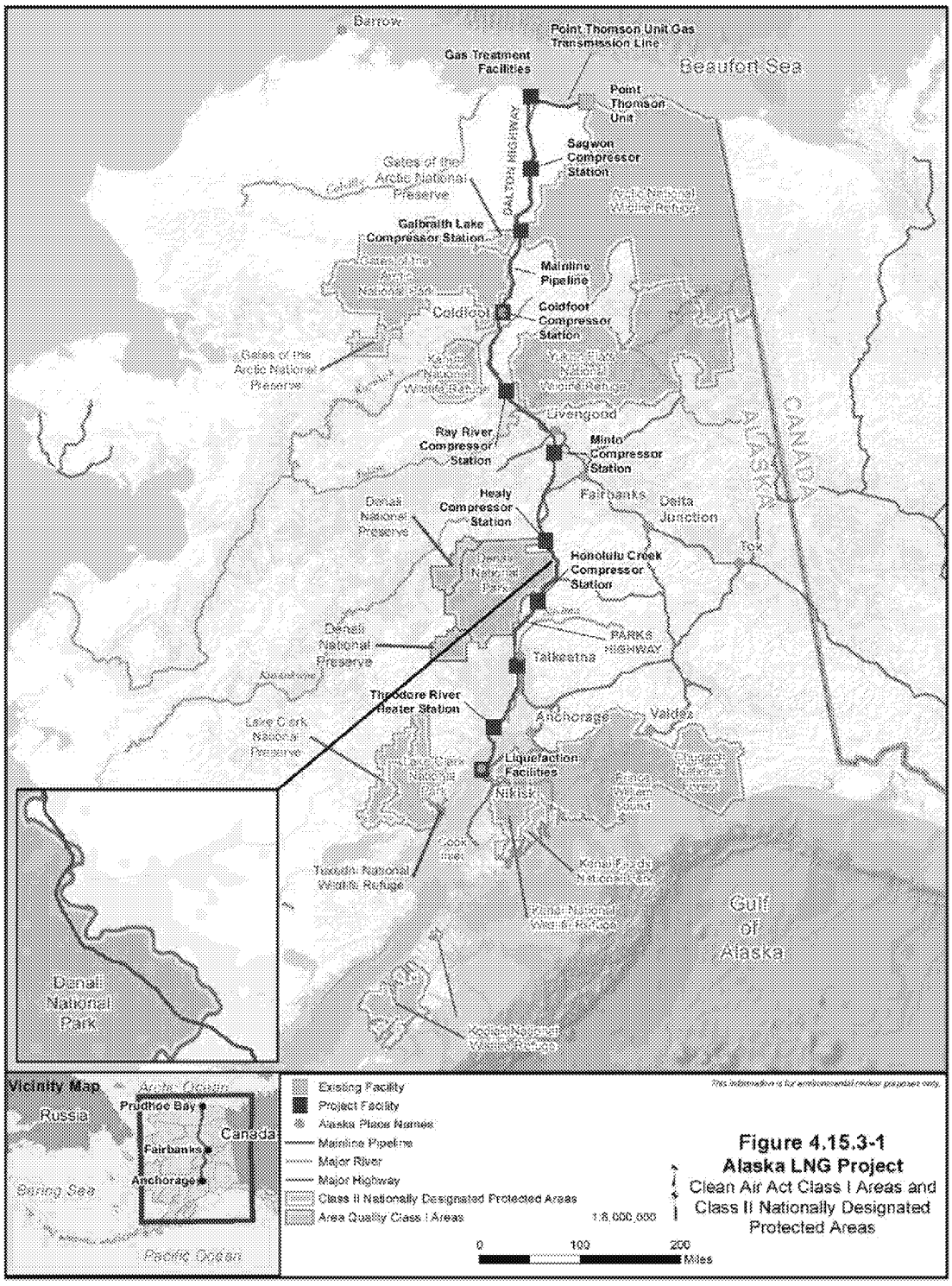
Figure 2. Class I and II Areas and the Proposed AK LNG Project.[69]



[69] FERC, "Alaska LNG Project Final Environmental Impact Statement." Vol. 3 at 4-924 (March 6, 2020), available at https://www.ferc.gov/sites/default/files/2020-05/03%2520Alaska%2520LNG%2520FEIS%2520Volume%25203.pdf.

III. Summary of Defects in the Draft Permit Proposal that Warrant Its Rejection

- Contrary to PSD permitting requirements, neither AGDC nor ADEC included expected emissions associated with the planned 800-mile pipeline that would transport natural gas from the North Slope to Nikiski. By not aggregating the emissions from the pipeline, gas treatment plant and compressor stations with those of the Liquefaction plant, AGDC would be allowed to treat the compressor stations and gas treatment plan as "minor" sources for air permitting purposes—a fact which will allow those facilities to escape the Clean Air Act's technology-based requirements (i.e., Best Available Control Technology (BACT), limitations on criteria air pollutants) and Maximum Achievable Control Technology (MACT), limitations on hazardous air pollutants) reviews applicable to "major" sources. Permitting the project as one PSD source would mean that the project's cumulative impacts on air quality including Class I AQRVs would need to be assessed collectively, which would best ensure that the goals of the PSD program are met.

- The BACT analyses for the six compressor turbines and the four power turbines are flawed because the draft permit fails to identify the make and model of each turbine to be installed, which is necessary to know achievable emission rates for several pollutants including greenhouse gases and NOx[70]

- NOx BACT for all of the compressor turbines should be based on application of selective catalytic reduction (SCR) because numerous BACT determinations have been made for combustion turbines that require SCR to meet BACT and because SCR will be cost effective. Indeed, ADEC recently proposed a PSD permit which would require SCR as BACT along with Solar turbines' SoLoNOx combustors for six power generating combustion turbines at the nearby Agrium U.S., Kenai Nitrogen Operations plant.[71] NOx limits with SCR would be 78% lower than the limits proposed by ADEC.

- The GHG BACT analysis for the turbines is deficient because the state failed to conduct source-specific analyses for: 1) carbon capture and sequestration; 2) use of electric compressors; and 3) use of the more efficient aeroderivative turbines (which appear to be a particularly good fit for the project and would help SCR work more efficiently). Moreover, Alaska's GHG BACT limit does not even require that a certain level of combustion efficiency be achieved at the combustion turbines. Alaska

[70] A policy reason for requiring PSD review, in addition to those discussed in preceding sections, is that subsequent PSD permits to other sources are premised on stability - and accuracy in determining - of the level of emissions from existing sources (in another context, the preamble to the 1980 PSD regulations explained the need for such accuracy and stability "[i]n EPA's view, any switch to another fuel or raw material that would distort a prior assessment of a source's air quality impact should have to undergo [PSD] scrutiny." 45 Fed. Reg. 52,676, 52,704 (1980).
[71] *See* Preliminary ADEC Technical Analysis Report for Construction Permit AQ0083CPT07 issued to Agrium U.S., Inc., for the Kenai Nitrogen Operations, November 20, 2020, Appendix B: Best Available Control Technology (BACT) at 7-8.

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has simply proposed a GHG BACT limit equivalent to EPA's GHG emission factor for all natural gas-burning sources.

- Alaska's BACT analysis for flaring is also deficient, because ADEC failed to consider capture and use requirements (in lieu of flaring the excess natural gas) or the use of a thermal incinerator instead of flaring (which results in better control of volatile organic compounds (VOCs) and NOx. Moreover, ADEC's proposed permit terms for its flaring BACT control of "minimization of flaring" are not adequate to ensure flaring is indeed minimized. ADEC has proposed to limit flaring during equipment startup, shutdown, and maintenance to 500 hours per year per flare, but is not limiting flaring due to plant upsets (likely the major cause of flaring) at all.

- The air quality modeling analyses supporting the Draft PSD Permit relied upon outdated modeling studies completed in 2017 or earlier for the AK LNG Project Final Environmental Impact Statement (FEIS). In addition, the FEIS modeling contained technical errors that tended to underestimate air quality impacts from the proposed Liquefaction plant, and these errors were carried forward to the PSD permit modeling. For example, the modeling failed to properly address maximum short-term impacts from expected flaring episodes at the Liquefaction plant. ADEC attempted to compensate for the known shortcomings in the modeling by performing additional technical analyses, but the ADEC "sensitivity studies" were themselves flawed and incomplete.

- The Class I impact analysis addressing DNPP and TUXE was faulty. In some cases, the AK LNG Project compressor stations would be within 5 km of DNPP, a protected Class I area, yet the Class I PSD increment analysis and air quality related values (AQRV) modeling addressing visibility and acid deposition impacts did not address the AK LNG Project compressor station emissions in combination with the Liquefaction plant and other regional emission sources. Also, the Class I impact modeling failed to address project-related maritime traffic in the Cook Inlet as it passed by TUXE. Despite errors in underestimating various Class I area impacts, the modeling still showed adverse air quality impacts at DNPP and TUXE; however, ADEC has refused to acknowledge such impacts and has not proposed any measures to alleviate the predicted adverse Class I impacts.

IV. The PSD Application is Materially Incomplete

A. ADEC Failed to Properly Define the AK LNG Project as the Source.

The requirements of the PSD program apply to "any new major stationary source,"[72] and "permitting authority must take into account the emissions from all parts of a single source when

[72] 40 C.F.R. § 52.21(a)(2); 18 AAC 50.040(h)(3).

determining the applicable requirements and conditions for operation of that source."[73] Federal and state regulations define a "stationary source" as "any building, structure, facility or installation that emits or may emit a regulated ... pollutant."[74] Both sets of regulations further define a "building structure, facility or installation" (and therefore a single "source") according to a three-part test. Under this test, a single source includes "all of the pollutant-emitting activities" that:

(a) *belong to the same industrial grouping* according to the federal government's Standard Industrial Classification (SIC) system,

(b) *are located on one or more contiguous or adjacent properties*, and

(c) *are under the control of the same person* (or persons under common control).[75]

Furthermore, as the D.C. District Court explained:

> Section 165 of the Act, 42 U.S.C. § 7475, provides that the owner or operator of a facility seeking a permit must demonstrate "that emissions from *construction or operation* of such facility will not cause, or contribute to, air pollution ...." 42 U.S.C. § 7475(a)(3) (emphasis added). Thus, the fact that construction is not aimed at completing a unit does not obviate the need for preconstruction review as the EPA [here ADEC] must consider the pollution resulting from the construction itself.[76]

Moreover, "pursuant to the plain language of the statute, and its obvious intent to regulate pollution attendant to the construction as well as the operation of the finished generating units," the permit application must include the emission units that comprise of the facility's structure.[77] The permitting authority "must prevent any construction not specifically presented and approved during the permit process. This is the only reading of the statute that will effect its manifest purpose."[78] In other words, if there are numerous emitting units and the permit applicant plans to build the emitting units in a manner that will facilitate all the units "accommodate[ing] the needs of full capacity operation," the overall structure of the facility must be presented in the PSD permit application.[79] "[I]f the EPA [here ADEC] did not have the opportunity to consider the cumulative impact of the additional construction resulting" from the other unit(s), "then the pollution control aims of the statute have not been protected."[80]

Finally, because determining the relevant source is a "fundamental" aspect of the PSD program, state permitting authorities are required to provide in the record a "reasoned explanation of their source determinations ... consistent with the Act."[81]

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[73] *In the Matter of Seneca Energy*, II, LLC, Order on Petition No. II-2012-01, at (June 29, 2015) (*2015 Seneca Energy Order*) available at https://www.epa.gov/sites/production/files/2016-08/documents/seneca_energy_ii_response_7-29-16_0.pdf.
[74] AS 46.14.990, 40 C.F.R. § 52.21(b)(5), (6).
[75] 40 C.F.R. § 52.21(b)(6)(emphasis added), AS 46.14.990.
[76] *Save the Valley v. Ruckelshaus*, 565 F. Supp. 709, 710 (D.C. Cir. 1983) (*Save the Valley*).
[77] *Id.*
[78] *Id.*
[79] *Id.* at 710-711.
[80] *Id.* at 711 (further explaining in n.3 that "...if the operator plans to install both lines at the same time, there is little burden in requiring it to present such plan to the EPA.")
[81] 2015 Seneca Energy Order at 10.

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There is no question that the AK LNG Project is one contiguous stationary source, and that all of the emitting activities that make up operations of the proposed project together comprise a single source of air pollution for purposes of the PSD program.

We start our analysis identifying the pollutant-emitting activities that make up the AK LNG Project: the Gas Treatment Plant (GTP), the compressor stations along the pipeline, the heater stations along the pipeline, the Mainline Pipeline itself, and the LNG facilities. Figure 3 below provides emissions estimates for these various activities that constitute the AK LNG Project, which were identified in the FEIS. FERC's Order authorizing the AK LNG Project included these same facilities.[82]

Figure 3. Emission Estimates for the AK LNG Project.

Pollutant-emitting activity	**NOx, tpy**	**CO, tpy**	**SO_2, tpy**	**$PM_{10}/PM_{2.5}$, tpy**	**VOC, tpy**	**HAPs, tpy**	**CO2e, tpy**
GTP (with Maximum Flare)[83]	3,782.1	9,100.1	1,076.3	903.2	13,263.3	108.0	6,607,655
Sagwon Compressor Station with Cooling[84]	184.6	247.8	4.8	29.1	33.4	10.7	233,785
Five Compressor Stations (Galbraith Lake, Coldfoot, Ray River, Minto, and Healy)[85]	161 (per station)	244.1 (per station)	4.3 (per station)	13.1 (per station)	21.0 (per station)	8.3 (per station)	206,381 (per station)

[82] 171 FERC ¶ 61,134 (May 21, 2020) (included as an attachment to these comments)(authorizing AGDC "to site, construct, and operate facilities in the State of Alaska for the liquefaction and export of natural gas produced in the North Slope of the State of Alaska (Alaska LNG Project)." at 1; and list of the pollutant emitting activities identified in Figure 4 of these comments are list with additional details in ¶¶ 3, 4 at 2-3) (FERC Order).

[83] *See* Table 4.15.5-1 of Volume 3 of the March 2020 Final EIS for the Alaska LNG Project, at page 4-937. This includes six natural gas compressor turbines, six CO2 compressor turbines, 6 power generating turbines, building heaters, generators, pumps, fugitive emissions, and flaring. *See also,* FERC Order at 2 ("a gas treatment plant in Prudhoe Bay on the North Slope consisting of three parallel treatment trains for the removal of carbon dioxide and hydrogen sulfide from the feed gas, each sized to process up to 1.3 Bcf/day of gas (Prudhoe Bay Treatment Plant)")

[84] *See* Table 4.15.5-11 of Volume 3 of the March 2020 Final EIS for the Alaska LNG Project, at page 4-947. This includes three compressor turbines, four natural gas powered generators, two auxiliary utility glycol heaters, one waste incinerator, and fugitive emissions and blowdowns. *See also,* FERC Order at 2 ("a compressor station with three gas-fired turbine compressor units, totaling 68,000 hp, located at Mainline Milepost (MP) 76.0 in the North Slope Borough (Sagwon Compressor Station)").

[85] *See* Table 4.15.5-12 of Volume 3 of the March 2020 Final EIS for the Alaska LNG Project, at page 4-948. Each of these compressor stations would include one compressor turbine, three power generators, two auxiliary utility glycol heaters, one waste incinerator, and fugitive emissions and blowdowns. *See also* FERC Order at 3 ("a compressor station with one 42,000 hp gas-fired turbine compressor unit, located at Mainline MP 148.5 in the North Slope Borough (Galbraith Lake Compressor Station); a compressor station with one 42,000 hp gas-fired turbine compressor unit, located at Mainline MP 240.1 in the Yukon-Koyukuk Census Area (Coldfoot Compressor Station); a compressor station with one 42,000 hp gas-fired turbine compressor unit, located at Mainline MP 332.6 in the Yukon-Koyukuk Census Area (Ray River Compressor Station); a compressor station with one 42,000 hp gas-fired turbine compressor unit, located at Mainline MP 421.6 in the Yukon-Koyukuk Census Area (Minto Compressor Station); a compressor station with one 42,000 hp gas-fired turbine compressor unit, located at Mainline MP 517.6 in the Denali Borough (Healy Compressor Station)").

Honolulu Creek Compressor Station[86]	131.6	200.5	3.5	10.6	13.7	6.6	166,013
Rabideux Creek Compressor Station[87]	144.8	220.7	4.0	12.1	14.7	6.8	191,658
Theodore River Heater Station[88]	49.3	103.4	2.6	8.7	16.3	4.2	125,201
Mainline Pipeline[89]							272[90]
Liquefaction Facilities Operation & Marine Terminal (with Maximum Flaring)[91]	4,257.3	14,136.9	184.5	1,324.6	21,480.8	145.2	7,901,876
Total Emissions of Project	**9,354.7**	**25,229.9**	**1,297.2**	**2,353.8**	**34,927.2**	**323.0**	**16,258,365**

Emissions from the Mainline Pipeline are incomplete and inaccurate. FERC estimated the GHG emissions from the Mainline Pipeline to be 272 tons of CO_2 equivalent (CO_2e) emissions per year.[92] The listed reference for this estimate was the Interstate Natural Gas Association of America database, 2005.[93] According to information on the emission factors of

[86] *See* Table 4.15.5-13 of Volume 3 of the March 2020 Final EIS for the Alaska LNG Project, at page 4-949. This compressor station would include one compressor turbine, three power generators, two auxiliary utility glycol heaters, one waste incinerator, and fugitive emissions and blowdowns. *See also* FERC Order at 3 ("a compressor station with one 33,000 hp gas-fired turbine compressor unit, located at Mainline MP 597.4 in the Matanuska-Susitna Borough (Honolulu Creek Compressor Station)").

[87] *Id.* This compressor station would include one compressor turbine, three power generators, two auxiliary utility glycol heaters, one waste incinerator, five indirect gas-fired heaters, and fugitive emissions and blowdowns. *See also* FERC Order at 3 ("a compressor station with one 33,000 hp gas-fired turbine compressor unit, located at Mainline MP 675.2 in the Matanuska-Susitna Borough (Rabideux Creek Compressor Station)").

[88] *See* Table 4.15.5-14 of Volume 3 of the March 2020 Final EIS for the Alaska LNG Project, at page 4-950. This includes two natural gas-fired power generators, nine indirect-fired natural gas heaters, one waste incinerator, fugitive emissions and blowdowns. *See also* FERC Order at 3 ("a stand-alone gas heater station, located at Mainline MP 749.1 in the Matanuska-Susitna Borough (Theodore River Heater Station)").

[89] *See* Table 4.15.5-15 of Volume 3 of the March 2020 Final EIS for the Alaska LNG Project, at page 4-950. These emissions would be mostly methane, and the pollutants would be emitted from "piping components and connectors along the Mainline Pipeline." Moreover, although AGDC did not quantify VOC emissions that would be released from the pipeline, there would undoubtedly be VOC emissions as well as CO2e (i.e., methane) emissions. *See* Table EC-3, Liquefaction Facility Fuel Specifications, of October 16, 2011 Emissions Calculations Report for the Liquefaction Facility, Appendix A at 57 (at pdf page 371 of the file entitled "AQ1539CPT01 Application Attachments 4 and 5"). *See also* FERC Order at 3 ("806.9 miles of 42-inch-diameter pipeline, which will extend from the Prudhoe Bay Treatment Plant and terminate at the Liquefaction Facilities on the Kenai Peninsula (Mainline Pipeline)").

[90] We disagree with this estimate. See discussion following this table.

[91] *See* Table 4.15.5-20 of Volume 3 of the March 2020 Final EIS for the Alaska LNG Project, at page 4-961. This includes six natural gas-fired compressor turbines, four natural gas-fired combined cycle power turbines, flaring, thermal oxidizer, LNG carriers and tugs, and other associated equipment. *See also* FERC Order at 3 ("liquefaction facilities capable of producing up to 20 MMTPA for export, located on the eastern shore of Cook Inlet in the Nikiski area of the Kenai Peninsula, consisting of feed gas mercury and water removal facilities, fractionation facilities, three liquefaction trains, two 240,000 cubic meter tanks, and marine facilities capable of accommodating two LNG carriers simultaneously (Liquefaction Facilities)").

[92] *See* Table 4.15.5-15 of Volume 3 of the March 2020 Final EIS for the Alaska LNG Project, at page 4-950.

[93] *Id.* Appendix Z of the FEIS lists the references for the EIS, the cited reference for "Interstate Natural Gas Association of America (2005), Table 4-3" was listed as the Interstate Natural Gas Association of America database available online at https://www.ingaa.org/.

this reference, it appears that the emission factors used only accounted for fugitive emissions from the pipeline itself and emissions from meters of which only two are planned for the Mainline Pipeline (one at the beginning and one at the end of the 806.6 mile pipeline).[94] However, can also occur due to blowdowns. A blowdown is a release of gas from a pipeline so that testing, maintenance, or repairs can be done on a section of pipeline. The Mainline Pipeline will have thirty mainline valves at which it can isolate a section of the pipeline that needs to be maintained or repaired.[95] Those valves are spaced as long as 46.6 miles apart to as close as 6.5 miles,[96] and the average distance between valves is 27.8 miles apart. EmIf we assume that all of the gas in an average length of the pipeline is vented in a blowdown for maintenance, that would equate to as much as 5.6 million cubic feet of gas purged.[97] AGDC states that 91.15% of the volume of natural gas would be methane,[98] thus the 5.6 million cubic feet of gas purged would equate to 5.15 million cubic feet of methane or 131,549 tons of methane from one blowdown on an average length of pipeline between mainline valves.[99] The CO_2e emissions from one blowdown event would be potentially as high as 3.28 million tons.[100]

As another source of fugitive emission estimates from natural gas pipelines, the Intergovernmental Panel on Climate Change (IPCC) has provided a methane emission factor of 0.0037 gigagrams per kilometer of U.S. natural gas transmission pipeline.[101] For the Mainline Pipeline, that would equate to 5,251 tons of methane emitted per year,[102] which equates to 131,278 tons per year of CO_2e emissions.[103] It is not clear whether the IPCC emission factor accounts for blowdowns.[104] Both of these CO_2e estimates are clearly much higher than FERC's estimate of 272 tons per year.

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[94] *See* Section 9.2.5.2.1.4 of Resource Report 9 of the April 2017 Alaska LNG Project Application to the Federal Energy Regulatory Commission, available at https://alaska-lng.com/regulatory-process/ferc-application-exhibits/resource-reports/.

[95] FEIS for Alaska LNG Project, Volume 3, at 4-1147 (Table 4.18.10-5).

[96] *Id.*

[97] Based on the stated Mainline Pipeline diameter of 42 inches, *see* FEIS for Alaska LNG Project at ES-1.

[98] *See* March 2018 Permit Application for Alaska LNG Project, Table EC-3, Liquefaction Facility Fuel Specifications, of October 16, 2011 Emissions Calculations Report for the Liquefaction Facility, Appendix A at 57 (at pdf page 371 of the file entitled "AQ1539CPT01 Application Attachments 4 and 5").

[99] Cubic feet of methane was converted to mass of methane based on the density of methane of 0.656 kilograms per cubic meter (51.07 lb/cubic foot), from July 2015, U.S. Department of Energy, Greenhouse Gas Emissions and Fuel Use within the Natural Gas Supply Chain – Sankey Diagram Methodology, at 15 (Appendix 2, Table 3), available at QER Analysis - Fuel Use and GHG Emissions from the Natural Gas System, Sankey Diagram Methodology_0.pdf (energy.gov)).

[100] The CO_2 equivalent emissions are calculated by multiplying the methane emissions by its global warming factor of 25. See 40 C.F.R. § 52.21(b)(49)(ii)(c) and 40 C.F.R. § 98, Table A-1.

[101] Intergovernmental Panel on Climate Change, "Fugitive Emissions from Oil and Natural Gas Activities," in *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories*, 103–127, 113 (2001), available at https://www.ipcc-nggip.iges.or.jp/public/gp/bgp/2_6_Fugitive_Emissions_from_Oil_and_Natural_Gas.pdf.

[102] Assuming an 800 mile length (or 1,287,5 kilometers) of the Mainline Pipeline, and using a conversion factor of 1,102.31 tons per gigagram.

[103] The CO_2 equivalent emissions are calculated by multiplying the methane emissions by its global warming factor of 25. *See* 40 C.F.R. §52.21(b)(49)(ii)(c) and 40 C.F.R. § 98, Table A-1.

[104] *See* Intergovernmental Panel on Climate Change, "Fugitive Emissions from Oil and Natural Gas Activities," in *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories*, at 118 (2001)

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Regardless of the scope of CO_2e emissions from the Mainline Pipeline, there is no question that the Mainline Pipeline is an emitting activity. In fact, not only will methane be emitted from the Mainline Pipeline, but also volatile organic compounds (VOCs) will be emitted from the pipeline. AGDC's permit application indicates that the LNG fuel gas will be approximately 2.3% by volume composed of VOCs such as Propane, IsoButane, Normal Butane, IsoPentane, N-Pentane, and other VOCs.[105] Thus, although FERC did not provide an estimate of VOC emissions for the Mainline Pipeline, fugitive emission releases from the pipeline will include VOC emissions because the gas stream will not be pure methane. With respect to blowdown emissions, the emissions of just one VOC, propane, which AGDC indicates would constitute 1.89% of the natural gas stream,[106] would potentially be as high as 8,346 tons from one blowdown of an average length of pipeline between valves.[107]

Permitting status of the emitting units. Before applying the single source test, it is important to explain the permitting status of the emitting units in Figure 3. According to ADEC's online database of issued permits, ADEC permitted the AGDC gas treatment plant (GTP) in a PSD permit (Construction Permit: AQ1524CPT01) on August 13, 2020.[108] In the Public Notice for the proposed Liquefaction plant, ADEC "has made a preliminary decision to approve Alaska Gasline Development Corporation's (AGDC's) application for Air Quality Control Construction Permit AQ1539CPT01 for the Liquefaction plant."[109] Thus, ADEC proposes to issue a separate PSD permit for the LNG Plant. Neither the pipeline compressor stations or heater station – that are part of the AK LNG Project - have, to our knowledge, been permitted by ADEC.[110]

The first part of the single source test is whether the pollutant-emitting activities are considered as part of the same industrial grouping. The pollutant-emitting activities are considered part of the same industrial grouping if they belong to the same *Major Group* (*i.e.,* which have the same two-digit code) as described in the *Standard Industrial Classification Manual, 1972,* as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101-0066 and 003-005-00176-0, respectively).[111]

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[105] *See* March 2018 Permit Application for Alaska LNG Project, Table EC-3, Liquefaction Facility Fuel Specifications, of October 16, 2011 Emissions Calculations Report for the Liquefaction Facility, Appendix A at 57 (at pdf page 371 of the file entitled "AQ1539CPT01 Application Attachments 4 and 5").
[106] *See* March 2018 Permit Application for Alaska LNG Project, Table EC-3, Liquefaction Facility Fuel Specifications, of October 16, 2011 Emissions Calculations Report for the Liquefaction Facility, Appendix A at 57.
[107] Cubic feet of propane was converted to mass of propane based on the density of propane of 2.010 kilograms per cubic meter (156.5 lb/cubic feet), from July 2015, U.S. Department of Energy, Greenhouse Gas Emissions and Fuel Use within the Natural Gas Supply Chain – Sankey Diagram Methodology, at 15 (Appendix 2, Table 3).
[108] *See* Alaska Department of Environmental Conservation Air Permits Program, "Technical Analysis Report For the terms and conditions of Construction Permit AQ1524CPT01 Issued to Alaska Gasline Development Corporation For the Gas Treatment Plant," (Aug. 13, 2020); Department of Environmental Conservation, "Air Quality Control Construction Permit: AQ1524CPT01," Alaska Gasline Development Corporation, Permittee (Aug. 13, 2020).
[109] Public Notice, State of Alaska, Department of Environmental Conservation, Alaska Gasline Development Corporation, Liquefaction Plant.
[110] There are no other permitted or proposed permits listed in ADEC's online database for the AGDC, nor does AGDC have any permit applications listed in ADEC's online "Queue" database listing. *See* Screenshot of ADEC Issued Air Permits; Screenshot of ADEC Permit Applications (included as attachments to these comments).
[111] AS 46.14.990, 40 C.F.R. § 52.21(b)(6).

The AGDC LNG Plant and the pipeline compressor stations all belong to the same industrial grouping – Major Group 49.[112] Specifically, the main pipeline and pipeline compressor stations fall under the industrial code of natural gas transmission (SIC 4922) and the LNG Plant falls under the standard industrial code of 4924 (Natural Gas Distribution).[113] In addition, ADEC has identified the Gas Treatment Plant as classified under Standard Industrial Classification Code 4922, so the GTP is also of the same Major Group 49.[114] Therefore, the AK LNG Project meet the first part of the test.

The second part of the single source test is whether the emitting units are on one or more contiguous or adjacent properties. First, the permit application for the Alaska LNG permit made available to the public by ADEC includes Resource Report No. 1 (April 14, 2017), which describes the emitting units that are part of the AK LNG Project, which are all connected to one another by the Mainline Pipeline which also is an emitting activity:

> [A] liquefaction facility (Liquefaction Facility) in Southcentral Alaska; an approximately 807-mile gas pipeline (Mainline); a gas treatment plant (GTP) within the PBU on the North Slope; an approximately 63-mile gas transmission line connecting the GTP to the PTU gas production facility (PTU Gas Transmission Line or PTTL); and an approximately 1-mile gas transmission line connecting the GTP to the PBU gas production facility (PBU Gas Transmission Line or PBTL)."[115]

The report further explains how the various units will facilitate operation of the AK LNG Project

> The Alaska Gasline Development Corporation (Applicant) plans to construct one integrated liquefied natural gas (LNG) Project (Project) with *interdependent facilities* for the purpose of liquefying supplies of natural gas from Alaska, in particular from the Point Thomson Unit (PTU) and Prudhoe Bay Unit (PBU) production fields on the Alaska North Slope (North Slope), for export in foreign commerce and for in-state deliveries of natural gas.[116]

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[112] Major Group 49 - Electric, Gas, and Sanitary Services. Major Group 49 also includes within it "Industry Group 494: Gas Production and Distribution." which are "[e]stablishments engaged in the transmission and/or storage of natural gas for sale"—most notably, "pipelines [for] natural gas"—as well as any establishments that combine aspects of electric generation and natural gas transmission. Though the Department of Labor has largely phased-out the Standard Industrial Classification (SIC) Manual in favor of the newer North American Industry Classification System, it maintains an online, hypertext edition of the Manual. *See* Department of Labor, SIC Division Structure, https://www.osha.gov/data/sic-manual.

[113] *See* NAICS Association, Standard Industrial Code Divisions, Major Group 49 – Electric, Gas, and Sanitary Service, available at https://www.naics.com/standard-industrial-code-divisions/?code=49. *See also* Alaska LNG Permit Application, Project Information Form at 1.

[114] *See* ADEC's Final Technical Analysis Report for the Alaska Gasline Development Corporation Gas Treatment Plant, Construction Permit AQ1524CPT01,August 13, 2020, at 2 (Section 1.2).

[115] Alaska LNG Permit Application, Resource Report No. 1 (April 14, 2017), at 1-1.

[116] Alaska LNG Permit Application, Resource Report No. 1 (April 14, 2017), at 1-1(emphasis added). This Resource Report is in the application file that was posted to ADEC's public notice website in October 2020 with the filename "AQ1539CPT01 Application Attachments 1 through 3.PDF" beginning at pdf page 82.

This report further explains that in order for the AK LNG Project to operate "*All of these facilities are essential* to export natural gas in foreign commerce and will have a nominal design life of 30 years."[117]

ADEC posted this report as part of the PSD permit application for the LNG plant stating that the LNG Terminal would include the following "interdependent facilities" among other facilities:

> **Mainline Facilities:** A new 42-inch-diameter natural gas pipeline approximately 807 miles in length would extend from the Liquefaction Facility to the GTP in the PBU,[118] including the structures, equipment, and all other associated systems. The proposed design anticipates up to eight compressor stations;[119] one standalone heater station, one heater station collocated with a compressor station, six cooling stations associated with six of the compressor stations; [120] four meter stations; 30 Mainline block valves (MLBVs)[121] one pig launcher facility at the GTP meter station, one pig receiver facility at the Nikiski meter station, and combined pig launcher and receiver facilities at each of the compressor stations;[122] and associated infrastructure facilities.[123]
>
> **GTP:** A new GTP and associated facilities in the PBU would receive natural gas from the PBU Gas Transmission Line and the PTU Gas Transmission Line. The GTP would treat/process the natural gas for delivery into the Mainline Pipeline. There would be custody transfer, verification, and process metering between the GTP and PBU for fuel gas, propane makeup, and byproducts. All of these would be on the GTP or PBU pads …[124]

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[117] *Id.* (emphasis added).

[118] The Mainline Pipeline would be buried with the exception of two aerial waterbody crossings, four aboveground crossings of active faults, and the 27.3-mile-long offshore portion in Cook Inlet, which would be laid on the seabed. *See* Final EIS, Vol. 1 at 2-13.

[119] Each compressor station includes one or more compressor turbines, 2-4 power generators, 1-2 glycol heaters, and a waste incinerator. *See* Final EIS, Vol. 1 at 2-16.

[120] "Natural gas engine-driven power generators would generate electric power for the compressor stations." Final EIS. Vol. 1 at 2-15.

[121] "Operating the Mainline Pipeline would require the installation of 30 MLVs ... MLVs would be at the GTP, at each of the eight compressor stations and the heater station, and at the LNG Plant. The remaining 18 MLVs would be stand-alone facilities installed within the Mainline Pipeline right-of-way. … Each MLV site would include a blowdown valve, a pipeline break control system, and an adjacent helipad." Final EIS. Vol. 1 at 2-17.

[122] "Launchers and receivers are facilities where internal pipeline cleaning and inspection tools, known as "pigs," are inserted or retrieved from the pipeline. Launchers/receivers generally consist of a 20- to 30-foot segment of aboveground piping that tie into the pipeline below the ground surface. A launcher would be installed at the GTP Meter Station; combined sets of launchers/receivers would be installed at each compressor and heater station; and a receiver would be installed at the Nikiski Meter Station." Final EIS, Vol. 1 at 2-18.

[123] Additional facilities include, for example: (1) Cathodic protection systems that help prevent corrosion of underground pipeline facilities. These systems typically include an aboveground transformer-rectifier unit and an associated anode ground bed underground. Select compressor stations, meter stations, and MLV sites would have cathodic protection system facilities (e.g., ground beds and rectifiers). Final EIS, Vol. 1 at 2-18. (2) Mainline MOF, which would consist of a pier and roll-on/roll-off ramp on the west side of Cook Inlet to support onshore and offshore pipeline construction, including AGDC placing fuel tanks on the dock to refuel barges. An average of 67 marine vessels per year would arrive at the Mainline MOF, with the peak year occurring in Year 2. Final EIS, Vol. 1 at 2-17 – 2-19.

[124] Alaska LNG Permit Application, Resource Report No. 1 (April 14, 2017), at 1-2.

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Natural Gas-Fired Heater Station: is also proposed to be located between the last compressor station (which will also have heaters) and the LNG Plant.[125] The FEIS for the project indicates that heaters will be used when ambient temperatures drop below freezing.[126]

Additional information demonstrates the contiguousness and interrelatedness of the AK LNG Project. For example, Figure 1.1-2 of Resource Report No. 1 is a schematic of the "Project Facilities Overview" that includes all of the air pollution sources mentioned (e.g., GTP facility, compressor stations, heater station, and the Liquefaction plant).[127] Furthermore, ADEC stated in its Technical Analysis Report for the GTP that it "is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaska's North Slope to international markets in the form of LNG."[128] The FEIS describes the primary function of the GTP as follows:

> The feed gas produced from the [Point Thompson Unit (PTU)] and [Prudhoe Bay Unit (PBU)] contains carbon dioxide (CO_2), hydrogen sulfide (H_2S), water and other impurities that require removal prior to liquefaction. The GTP would remove these byproducts from the natural gas, then chill, compress, and send out processed natural gas into the Mainline Pipeline.

FEIS at 2-2 (Section 2.1.3.1) (emphasis added).[129]

The Mainline Pipeline and associated facilities has the primary purpose of transmitting the treated gas to the Liquefaction plant. According to the FEIS for the AK LNG Project, the eight compressor stations currently planned, "would use natural gas-fired engines to maintain pressure within the Mainline Pipeline to deliver the contracted volumes of natural gas to the Liquefaction Facilities."[130] Furthermore, FERC's order also describes the connected nature of the AK LNG Project, explains that it consists of

> [A] gas treatment plant located in the Prudhoe Bay Unit of Alaska's North Slope, and two natural gas pipelines connecting production units to the gas treatment plant; an approximately 806.9-mile-long, 42-inch-diameter pipeline (Mainline Pipeline) capable of transporting up to 3.9 billion cubic feet of gas per day (Bcf/day) from the gas treatment plant to the liquefaction facilities; 344,000 horsepower (hp) of compression located at eight compressor stations along the Mainline Pipeline; and liquefaction facilities on the

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[125] *See* March 2020, Federal Energy Regulatory Commission, Final Environmental Impact Statement, Alaska LNG Project, Volume 1 at 2-15.
[126] *Id.* at 2-58.
[127] Alaska LNG Permit Application, Resource Report No. 1 (April 14, 2017), at 1-3.
[128] *See* ADEC's Final Technical Analysis Report for the Alaska Gasline Development Corporation Gas Treatment Plant, Construction Permit AQ1524CPT01, August 13, 2020, at 2 (Section 1.3).
[129] *See* March 2020, Federal Energy Regulatory Commission, Final Environmental Impact Statement, Alaska LNG Project, Volume 1 at 2-2, available at https://www.ferc.gov/industries-data/natural-gas/final-environmental-impact-statement-0.
[130] *Id.* at 2-14. *See also* FERC, "An Interstate Natural Gas Facility on My Land?: What Do I Need to Know?" at 28 (2015), available at https://www.ferc.gov/sites/default/files/2020-04/AnInterstateNatualGasFacility.WhatYouNeedToKnow.pdf (natural gas pipeline projects need "[c]ompressor stations" to be "strategically placed along the pipeline to boost the system pressure to maintain required flow rates.")

Kenai Peninsula designed to produce up to 20 million metric tons per annum (MMTPA) of LNG (Liquefaction Facilities) for export.[131]

Although the precise number of gas interconnections are unclear, AGDC plans contemplate interconnections for in-state deliveries of natural gas, and ADEC should evaluate those projects consistent with the single source analysis presented in these comments. As currently planned, the FEIS indicated that the Mainline Pipeline will have, at a minimum, three gas interconnections "to allow for future in-state deliveries of natural gas" to serve the Fairbanks area, the Anchorage/Matanuska-Susitna Valley area, and the Kenai Peninsula area.[132] While FERC's final order explains that "AGDC states that along the mainline there will be at least five gas interconnection points to allow for future in-state deliveries of natural gas,"[133] the extent of any such interconnections to take some of the natural gas destined for the LNG plant is currently unknown.[134] Additional facilities would need to be constructed to move the natural gas from the interconnection points to the in-state customers. Indeed, the FEIS indicates that "[t]here are currently no plans to construct additional facilities, such as off-take stations, lateral pipelines, or distribution systems, to provide future natural gas deliveries to in-state customers."[135] Thus, as currently proposed, the GTP and pipeline compressor stations would be solely for the purpose of transporting the treated natural gas to the LNG plant. Even if at some point in the future there are in-state customers serviced by the gas that is processed through the GTP and the Mainline Pipeline compressor stations, the GTP and Mainline Pipeline compressor stations would still be integral to the ability of the LNG plant to create the liquefied natural gas product. Moreover, that the Project may at some point deliver gas to locations other than the Liquefaction plant in inapposite. Structures that will be used in common by more than one unit must be presented in the permit application nonetheless.[136]

The third part of the test is whether the pollutant-emitting activities are under control of the same person. Alaska's SIP defines "person" broadly as any "individual, corporation, partnership, association, a governmental body, a municipal corporation, or any other legal entity."[137] The GTP, the main pipeline, the compressor stations, and the LNG Plant will be under the control of the same person – i.e., the Alaska Gasline Development Corporation. On April 26, 2018, the AGDC submitted the initial PSD Application for the LNG Plant to ADEC - although it was found by ADEC to be incomplete and based on the missing information identified in these comments, is still incomplete – the PSD permit application was submitted by

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[131] FERC Order at 2.
[132] FEIS Volume 1 at 2-20.
[133] FERC Order at 2.
[134] *See* March 2020, Federal Energy Regulatory Commission, Final Environmental Impact Statement, Alaska LNG Project, Volume 3 at 4-1165, available at https://www.ferc.gov/industries-data/natural-gas/final-environmental-impact-statement-0.
[135] *Id.*
[136] *Save the Valley at* 711.
[137] AS 46.14.990(21)("person" has the meaning given in AS 01.10.060 and also includes an agency of the United States, a municipality, the University of Alaska, the Alaska Railroad Corporation, and other departments, agencies, instrumentalities, units, and corporate authorities of the state;"); AS 01.10.060(a)(8)("person" includes a corporation, company, partnership, firm, association, organization, business trust, or society, as well as a natural person.)

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AGDC.[138] The construction permit ADEC issued for the GTP was also issued to the AGDC.[139] On April 17, 2017, AGDC filed an application under section 3 of the Natural Gas Act (NGA) and Part 153 of the FERC's regulations for authorization to site, construct, and operate facilities in the State of Alaska for the liquefaction and export of natural gas produced in the North Slope of the State of Alaska (AK LNG Project).[140] FERC's order granted authorization to AGDC for the proposed AK LNG Project, which as described in the footnotes to Figure 3, contain the same emitting units covered by CAA requirements. Moreover, while FERC's order described AGDC as a "public corporation," the definition of person includes "corporate authorities of the state."[141]

Thus, the GTP, the Mainline Pipeline compressor stations, the heater station, and the LNG plant should all be considered as one major stationary source under the PSD permitting program. All of these sources have common ownership and control, in that the AGDC is the current owner and planned operator of all of these facilities. In addition, all of the facilities are classified under the same major Standard Industrial Classification code of 49 – Electric, Gas and Sanitary Services. And, all the emitting units are connected to each other by the Mainline Pipeline and contiguous and adjacent to one another.

Importantly, the underground pipeline is itself a "pollutant-emitting activity" producing methane and volatile organic compound emissions from component leaks[142] and periodic blowdown[143] activities.[144] Metering and regulating stations, valves, and the pipeline itself also

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[138] ADEC Air Quality Construction Permit Application, Permit Information Form, Section 2, at 1.

[139] Air Quality Control Construction Permit: AQ1524CPT01 at 1.

[140] FERC Order at 1.

[141] FERC Order at 1 ("AGDC is an independent, public corporation of the State of Alaska structured within the Department of Commerce, Community, and Economic Development. The Alaska State Legislature provided AGDC with the authority and primary responsibility for developing a liquefied natural gas (LNG) project on the State's behalf.").

[142] Although so-called "fugitive emissions" from component leaks are not always included in determining whether the potential to emit of a stationary source exceeds the major stationary source emission thresholds under the PSD program, Alaska's SIP unequivocally considers such fugitive emissions to be "emissions of a stationary source." *See* 18 AAC 50.990(52) and 40 C.F.R. §51.166(b)(1).(definition of "major stationary source"). Accordingly, fugitive emissions from otherwise major sources are included in "all subsequent analyses, including PSD applicability for other individual pollutants (i.e., comparing emissions to the significant emission rates), BACT analyses, and air quality impact analyses." Environmental Protection Agency, *Counting GHG Fugitive Emissions in Permitting Applicability*, 2 (July 2015), available at https://www.epa.gov/sites/production/files/2015-07/documents/ghgfeqa.pdf.

[143] "Blow" or "blowdown" activities involve the venting of natural gas contained inside a pipeline into the atmosphere. *See* Environmental Protection Agency, *Methane Emissions from the Natural Gas Industry, Vol. VII: Blow and Purge Activities*, 2 (1996), available at https://www.epa.gov/sites/production/files/2016-08/documents/7_blowandpurge.pdf, which are planned here. *See also,* FERC Order at 79 ("Blowdowns would occur at compressor stations and mainline valves as part of normal pipeline safety operations.").

[144] *See also* Environmental Protection Agency, *Oil and Natural Gas Sector Leaks*, 3, 21–22 (2014); *Oil and Natural Gas Sector: Emission Standards for New and Modified Sources*, 80 Fed. Reg. 56593, 56607 (proposed Sept. 18, 2015)("In addition to vented emissions, methane losses can occur from leaks (also referred to as fugitive emissions) in all parts of the [natural gas] infrastructure, from connections between pipes and vessels, to valves and equipment"); *id.* at 56642 (even a natural gas transmission "facility with proper operation would likely find one to three percent of components to have fugitive emissions")); Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (1990-2018), 3-84, available at https://www.epa.gov/sites/production/files/2020-04/documents/us-ghg-inventory-2020-main-text.pdf ("Emissions

have the potential to emit volatile organic compounds and greenhouse gases. As such, the above- and below-ground facilities associated with the pipeline component of the proposed source must be identified in the PSD permit application.[145]

Furthermore, although the highly unique facts of the AK LNG Project demonstrate that all the emitting units identified in Figure 4 must be permitted as a single source under the PSD program, EPA's historical analysis of the functional relationship or the functional interrelatedness between facilities to determine whether they should be considered "contiguous and adjacent" and thus one stationary source, also supports aggregating the AK LNG Project components.

For example, in a 1996 determination, the EPA found that the Anheuser-Busch brewery and the Nutri-Turf landfarm that were about six miles apart were nonetheless considered to be a single stationary source.[146] In this case, the facilities were under common ownership and the brewery wastewater stream was piped to the landfarm where it was disposed. EPA found that the volatile organic compound emissions at the landfarm were a "direct result of brewery operations."[147] EPA relied heavily on the fact that the landfarm was a "support facility" to the brewery to make this determination even though the landfarm had a different two digit major SIC code than the brewery.[148] EPA defined "support facilities" as "those that convey, store, or otherwise assist in the production of the principal produce or group of products produced or distributed…."[149] With respect to whether the facilities were considered "contiguous or adjacent," EPA stated that it considered the two facilities to meet this criteria because "the landfarm operation is an integral part of the brewery operations" and stated that "[t]he additional fact that a *pipeline physically connects the brewery and landfarm* strengthens the conclusion that the brewery operation is dependent on the landfarm operations."[150] EPA relied on the functional

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from normal operations [natural gas systems] include: natural gas engine and turbine uncombusted exhaust, flaring, and leak emissions from system components. Routine maintenance emissions originate from pipelines, equipment, and wells during repair and maintenance activities. Pressure surge relief systems and accidents can lead to system upset emissions.) 3-84. Environmental Protection Agency National Risk Management Research Laboratory, *Methane Emissions from the Natural Gas Industry, Vol. IX: Underground Pipelines*, 55–57 (1996), available at https://nepis.epa.gov/Exe/ZyNET.exe/P100UMFU.TXT?ZyActionD=ZyDocument&Client=EPA&Index=1995+Thru+1999&Docs=&Query=&Time=&EndTime=&SearchMethod=1&TocRestrict=n&Toc=&TocEntry=&QField=&QFieldYear=&QFieldMonth=&QFieldDay=&IntQFieldOp=0&ExtQFieldOp=0&XmlQuery=&File=D%3A%5Czyfiles%5CIndex%20Data%5C95thru99%5CTxt%5C00000039%5CP100UMFU.txt&User=ANONYMOUS&Password=anonymous&SortMethod=h%7C-&MaximumDocuments=1&FuzzyDegree=0&ImageQuality=r75g8/r75g8/x150y150g16/i425&Display=hpfr&DefSeekPage=x&SearchBack=ZyActionL&Back=ZyActionS&BackDesc=Results%20page&MaximumPages=1&ZyEntry=1&SeekPage=x&ZyPURL; *See also* Environmental Protection Agency Region VI, PSD Permit Statement of Basis for Apex Matagorda Energy, Permit No. PSD-TX-107055-GHG, 6 (Jan. 2013), available at https://archive.epa.gov/region6/6pd/air/pd-r/ghg/web/pdf/apex-matagorda-sob013114.pdf (including within source and applying BACT to natural gas pipeline and metering station supplying power plant).

[145] 18 AAC 50.040(h)(12), 40 C.F.R. § 52.21(n).

[146] *See* EPA Memorandum with Subject: "Analysis of the Applicability of Prevention of Significant Deterioration (PSD) to the Anheuser-Busch, Incorporated Brewery and Nutri-Turf, Incorporated Landfarm at Fort Collins, Colorado," available at https://www.epa.gov/nsr/analysis-applicability-psd-anheuser-busch-incorporated-brewery-and-nutri-turf-incorporated (Aug. 27, 1996).

[147] *Id.* at 2.

[148] *Id.* at 3.

[149] *Id.*

[150] *Id.* at 4 (emphasis added).

interrelatedness of the two facilities in determining that such facilities should be considered "contiguous or adjacent."

There have been other examples of EPA single source determinations involving facilities that were located some distance apart, including the following:

1) *American Soda Commercial Mine and Processing Plant in Colorado.* This mine and processing plant were to be 35-40 miles apart, connected by a 44-mile pipeline. EPA found that the two facilities "clearly will be functionally interdependent, as evidenced by the dedicated slurry pipeline and the spent brine return pipeline which will connect the two facilities."[151] EPA also stated that "[a]dditional evidence is that one facility (the mine) is to produce an intermediate product for processing at the other facility (the processing plant)" and that due to "the integral connectedness of these facilities," the distance between the facilities should not preclude the facilities from being considered adjacent.[152]

2) *Great Salt Lake Minerals plant and a pump station in Utah.* This was a minerals plant located on one side of the Great Salt Lake and a pumping station on the other size of the Great Salt Lake, 21.5 miles apart. EPA found that the pumping station, which transported raw materials to a processing plant, was a support operation to the minerals plant.[153]

3) *District Energy St. Paul Combined Heat and Power Plant and Environmental Wood Supply in Minnesota.* The District Energy St. Paul power plant was a biomass-fueled power plant, and it obtained its biomass from Environmental Wood Supply, which was located 3 miles from the power plant.[154] EPA states that "[e]ach day, seven days per week, [Environmental Wood Supply] transports by public roadway up to 40 truck-loads of fuel-grade product" for use in the biomass-fueled power plant.[155] EPA found that despite these two plants not having the same major group standard industrial classification code, Environmental Wood Supply and District Energy St. Paul had a "support or dependency relationship" because Environmental Wood Supply provided the necessary fuel to the power plant which it needed to produce electricity.[156] EPA also found that the two facilities had common ownership and thus were under common control.[157]

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[151] *See* EPA Letter from Richard R. Long, Air and Radiation Program, EPA Region VIII, to Mr. Dennis Myers, Air Pollution Control Division, Colorado Department of Public Health and Environment, at 1, available at https://www.epa.gov/nsr/american-soda-multi-facility-source-determination (April 20, 1999).
[152] *Id.*
[153] *See* EPA letter from Richard R. Long, Air Program, EPA Region VIII, to Lynn R. Menlove, New Source Review Section, Utah Department of Environmental Quality, at 1-2, available at https://www.epa.gov/nsr/great-salt-lake-minerals-source-determination (Aug. 8, 1997).
[154] *See* EPA letter from Pamela Blakely, Air Permits Section, EPA Region V, to Don Smith, Air Quality Permits Section, Minnesota Pollution Control Agency, at 1, available at https://www.epa.gov/nsr/single-source-applicability-determination-environmental-wood-supply-llc-and-district-energy-st (March 23, 2010).
[155] *Id.* at 2.
[156] *Id.*
[157] *Id.* at 4.

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There are key similarities between these EPA single-source determinations and the AGDC's proposed liquefied natural gas project. For example, as discussed above, there are other EPA single source determinations involving facilities that were some distance apart. First, EPA found the two facilities American Soda Commercial Mine and Processing Plant in Colorado, which were 35-40 miles apart and connected by a 44-mile pipeline, were functionally interdependent. Due to their integral connectedness, and the distance between them did not preclude the facilities from being considered adjacent. These points also apply to the GTP, compressor stations, and the LNG plant. The GTP will produce the intermediate product (i.e., natural gas that meets necessary limitations for the Liquefaction plant) that will then be transported via pipeline to the liquified natural gas plant, where it will undergo liquification and distribution. In addition, the GTP, compressor stations and the LNG plant are interconnected. The LNG plant would not be able to exist if it weren't for the GTP and the compressor stations moving the gas through the pipeline to the LNG plant. And the GTP and the pipeline compressor stations would not exist without the LNG plant to liquefy the gas such that it can be sold and transported.

Second, the minerals plant and pump station at the Great Salt Lake Minerals facility in Utah were on opposite sides of the Great Salt Lake, 21.5 miles apart, and EPA found that the pumping station, which transported raw materials to a processing plant, was a support operation to the minerals plant. Similarly, the AGDC compressor stations will transport the natural gas to the Liquefaction plant, and in one location also crossing the water. Thus, the compressor stations are support operations necessary to the Liquefaction plant.

Furthermore, the AK LNG Project will consist of facilities that are, on average, approximately 90 miles apart from each other (i.e., GTP to 1st compressor station, or compressor station to compressor station, or heater station to LNG plant). While it is not clear whether EPA has previously found that a collection of facilities like this should be considered one source under the PSD permitting program, the fact is that the AK LNG Project is a unique source. One of the circumstances that makes the AK LNG Project unique is that the sources of natural gas are in northern Alaska, but the best shipping routes for transport of the liquefied natural gas to international clients are 800 miles to the South in the Cook Inlet. Because of concerns with such a long pipeline going through the Alaskan wilderness with most of the length of the pipeline traveling over permafrost,[158] it is necessary to have the GTP both remove acid gases that could be corrosive to the pipeline (potentially resulting in pipeline leaks that could be damaging to wildlife and the environment) and to chill the natural gas (so as not to negatively affect the permafrost).[159]

The relationship between the gas treatment facility and Liquefaction plant is established. As stated in the FEIS, the Liquefaction plant is necessary to remove several impurities from the natural gas that must be removed prior to liquefaction.[160] There are several examples of LNG plants where the gas treatment facilities and the liquefaction plants are collocated. At the proposed Jordan Cove Energy Project LNG terminal to be located in Coos Bay, Oregon, there

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[158] *See* March 2020, Federal Energy Regulatory Commission, Final Environmental Impact Statement, Alaska LNG Project, Volume 1, at 4-70.
[159] *Id.* at 2-7, 4-105.
[160] *Id.* at 2-2.

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are plans for gas treatment facilities (including acid gas removal) at the same location as the liquefaction facilities.[161] The Golden Pass LNG Plant under construction in Texas also is proposed to have gas treatment facilities including acid gas removal systems collocated with the liquefaction facilities.[162] Additionally, existing LNG operations collocate the gas treatment and liquefaction activities.[163] The fact that the AGDC gas treatment facilities are located approximately 800 miles from AGDC's proposed Liquefaction appears to be a function of the fact that the AK LNG Project is planned within the state of Alaska, with its unique characteristics that necessitate the project being constructed in the manner in which it was proposed. However, those facts do not discount the requirement that the GTP, the Mainline Pipeline, the compressor stations and heater station, and the Liquefaction plant are parts of a single project and therefore must be considered as a single major stationary source under the PSD permitting program. In this case, while the facilities are all inherently related to AGDC's ability to operate a liquefaction plant, the facilities must be separated in distance. That unique fact should not result in a finding that commonly-owned facilities of the same major two-digit Standard Industrial Classification Code proposed for the same purpose (i.e., to operate an LNG plant) are not a single stationary source, because that would be inconsistent with the PSD permitting regulations.

Moreover, Alaska did not adopt in its SIP regulations the optional regulatory provisions offered in EPA's 2016 rulemaking, and even if it had, the optional provisions would not apply to the GTP, pipeline, compressor stations heater, and Liquefaction plant because they are all part of natural gas transmission, not natural gas production. This rule is where EPA included an optional approach to the aggregation of oil and gas production activities.[164] That rule expressly excludes both natural gas transmission operations like the Mainline and the emitting units at the beginning, end and along the pipeline. As EPA explained, the rule was designed to address the "unique" circumstances of the gas production industry - circumstances absent from the gas transmission and LNG facilities.[165] In fact, EPA's 2016 rule clarifies only the term "adjacent" *Id.* at 35633, what is "contiguous," was not changed.[166]

Additionally, the unique facts of the AK LNG Project are clearly different from the discussion and examples provide in EPA's 1980 preamble where it promulgated amendments to the PSD regulations, where it formulated a new definition of source to include the SIC two-digit categories to classify each source. EPA's preamble language ignored the fact that pipelines are pollutant-emitting activities – not just methane, but also VOCS.[167] Notably, methane emissions

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[161] *See* Jordan Cove Energy Project, L.P., LNG Terminal, Type B State New Source Review Application, prepared for Jordan Cove Energy, LLC., at 3 (Sept. 2017), available at https://www.oregon.gov/deq/Programs/Documents/JCEPAQPermitAppl2017.pdf.
[162] *See* Golden Pass Products, LNG Terminal PSD Permit Application (Dec. 2013) at 4-1 to 4-2.
[163] *See* FERC "LNG," available at https://www.ferc.gov/industries-data/natural-gas/overview/lng; FERC, "LNG Maps Exports," available at https://www.ferc.gov/media/lng-maps-exports; Cameron LNG, available at https://cameronlng.com/lng-facility/lng-and-liquefaction/; Freeport LNG, available at https://freeportlng.com/.
[164] *See* Source Determination for Certain Emission Units in the Oil & Natural Gas Sector, 81 Fed. Reg. 35622, 35630 (June 3, 2016).
[165] *Id.*
[166] *Id.*
[167] 45 Fed. Reg. 52676, 52695 (Aug. 7, 1980) (For example, in this example from EPA, it characterized a multistate pipeline, "Many commenters urged EPA to clarify the extent to which the final definition of those terms

were not regulated by the CAA in 1980, and therefore, examples EPA offered in the preamble did not consider fugitive methane emissions from natural gas pipelines.[168] Natural gas pipelines are also sources of volatile organic compound emissions, which EPA's 1980 preamble statement did not recognize. Furthermore, there is no indication whatsoever that EPA 's hypothetical "long-line operation" was – like the Mainline Pipeline - itself a pollutant emitting activity. In fact, that EPA believed a clarification on this point to be unnecessary suggests precisely the opposite: the preamble merely describes a smattering of discrete activities, separated by many miles, unconnected by any intervening pollutant-emitting activities.[169] Therefore, it would be unreasonable to suggest that those examples are relevant to the source determination for the AK LNG Project,[170] particularly given the fact-specific nature of source determinations, which EPA repeatedly noted in its determinations.

Finally, it would also be unreasonable to suggest that only two factors in EPA's 1980 preamble discussion regarding "common sense notion of 'plant'" and the definition of source for PSD purposes "must avoid aggregating pollutant-emitting activities that as a group would not fit within the ordinary meaning of 'building,' 'structure,' 'facility," or 'installation,'"[171] should be used in the AK LNG Project analysis. Not only are they just two of the three boundaries that in EPA's view, it thought were set by the court in Alabama Power, more importantly, the first boundary EPA identified is that the definition of source for purposes of PSD "must carry out reasonably the purposes of PSD."[172] Section 160 of Part C of the Clean Air Act lists the following purposes of the Prevention of Significant Deterioration Program:

> (1) to protect public health and welfare from any actual or potential adverse effect which in the Administrator's judgment may reasonably be anticipate to occur from air pollution

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encompasses the activities along a "long-line" operation, such as a pipeline or electrical power line. For example, some urged EPA to add to the definition the provision that the properties for such operations are neither contiguous nor adjacent. To add such a provision is unnecessary. EPA has stated in the past and now confirms that it does not intend "source" to encompass activities that would be many miles apart along a longline operation. For instance, EPA would not treat ell of the pumping stations long a *multistate pipeline* as one "source.") (emphasis added)

[168] EPA regulated methane from oil and gas sources, including fugitive emissions from compressor stations, under section 111 of the Clean Air Act in 2016. 40 CFR 60.5360a-.5432a (2016). Though EPA recently deregulated methane and removed transmission and storage segments under section 111, *see Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review*, 85 Fed. Reg. 57,018 (Sept. 14, 2020), that action has is currently being challenged in Federal court. *See State of California, et al v. Wheeler*, Case No. 20-1357 (D.C. Cir. 2020).

[169] Furthermore, there is nothing in EPA's 1980 preamble to suggest that its language has independent legal effect. In light of the examples of EPA's historical single source determinations presented above, it is clear EPA did not intend to bind either itself, states or regulated entities by the preamble language. Additionally, it is improper to consult the preamble to rule, because the meaning of the rule is clear on its face.

[170] Examples of inapposite phrases in EPA's preamble include (1. "EPA has stated in the past and now confirms that it does not intend 'source' to encompass activities that would be many miles apart along a longline operation." 2. "For instance, EPA would not treat all of the pumping stations along a multistate pipeline as one 'source.'" 3. "EPA is unable to say precisely at this point how far apart activities must be in order to be treated separately. The Agency can answer that question only through case-by-case determinations. One commenter asked, however, whether EPA would treat a surface coal mine and an electrical generator separated by 20 miles and linked by a railroad as one "source," if the mine, the generator, and the railroad were all under common control. EPA confirms that it would not. First, the mine and the generator would be too far apart. Second, each would fall into a different two-digit *SIC* category.") *Id.*

[171] *Id.* at 52694-52695 (and offering that in EPA's view, the court in *Alabama Power*, set such boundaries).

[172] *Id.*

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> or from exposures to pollutants in other media, which pollutants originate as emissions to the ambient air), notwithstanding attainment and maintenance of all national ambient air quality standards;
>
> (2) to preserve, protect, and enhance the air quality in national parks, national wilderness areas, national monuments, national seashores, and other areas of special national or regional natural, recreational, scenic, or historic value;
>
> (3) to ensure that economic growth will occur in a manner consistent with the preservation of existing clean air resources;
>
> (4) to assure that emissions from any source in any State will not interfere with any portion of the applicable implementation plan to prevent significant deterioration of air quality for any other State; and
>
> (5) to assure that any decision to permit increased air pollution in any area to which this section applies is made only after careful evaluation of all the consequences of such a decision and after adequate procedural opportunities for informed public participation in the decisionmaking process.

Section 160 of the Clean Air Act, 42 U.S.C. § 7470.

A decision not to treat the AK LNG Project as one source is contrary to the purpose of the Act. For example, without conducting the required PSD analysis, the FEIS for the AK LNG Project incorrectly suggests that the Mainline Pipeline compressor stations and heater station would be considered new minor sources under the PSD program.[173] Moreover, the GTP was previously issued a separate major source PSD permit by ADEC in August 2020, which occurred without ADEC conducting the required analysis of what constitutes the source. If the AK LNG Project is split up into a major and minor source construction permits, then the purposes of the PSD program, including the requirement to assure that "any decision to permit increased air pollution…is made only after careful evaluation *of all of the consequences* of such a decision…"[174] will not be met.[175] In addition, the Liquefaction plant and the compressor stations will impact the same public lands including Class I areas and thus, to ensure that the air quality in the affected national parks and wilderness areas are preserved, protected, and enhanced, it is imperative that all of the facilities that are truly part of the same project be permitted as such. Indeed, several compressor stations are right on the doorstep for Denali. If separate permits were issued for each emitting activity, that would mean some sources would receive minor source permits (e.g., all the compressor stations and heater station) and would not be subject to the more rigorous analysis, more stringent BACT emission limitations and permits with more robust terms and conditions for such elements as monitoring recordkeeping and reporting.[176] ADEC cannot

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[173] *See* March 2020, Federal Energy Regulatory Commission, Final Environmental Impact Statement, Alaska LNG Project, Volume 3 at 4-922.

[174] Section 160(5) of the Clean Air Act, 42 U.S.C. §7470(5) (emphasis added).

[175] Furthermore, the minor sources would evade the PSD BACT analysis and review requirements.

[176] Additional differences between PSD and minor source permits include: minor sources escape the requirement to obtain a Title V permit (which means no opportunity for the public to review and comment on the ongoing operations, gap-filing for monitoring, recordkeeping and reporting of emissions, and other requirements); there is no involvement for the FLMs in minor source permits; 18 AAC 50.540(l) includes provisions for exemption of minor

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ensure that the purposes of the PSD program would be met under such a scenario. Finally, it is undisputed that the aboveground[177] and underground pipeline itself will emit air pollution in the form of greenhouses gases, including methane, and if it is not aggregated with the rest of the AK LNG Project, it would evade the substantive requirements of the PSD program-including, most notably, a review of technologies to control greenhouse gas emissions from its above-and below-ground components.[178] This is not, then, a case where the practical advantages of administering multiple permits at no real cost to environmental quality justifies a purely technical departure from the definition of a single "source."[179] ADEC must follow the plain language of its own regulations and consistent with the purposes of the Act, treat all facilities associated with the AK LNG Project as one source for purposes of PSD permitting. Finally, until such time as AGDC substantially amends its PSD permit application to include the missing analysis and information, the ADEC cannot approve the proposal in conformance with Alaska's SIP or the Clean Air Act.

B. ADEC's Analysis Fails to Include a Detailed Schedule for Construction and Operation of the Sources.

The PSD permit application must include, at a minimum, information on the location, design capacity, and *typical operating schedule of the source, a detailed schedule for construction*, and a description of the control technology that is proposed as BACT,[180] and these requirements are in Alaska's regulations.[181]

ADGC failed to include the detailed construction schedule in its application for the proposed Liquefactions plant, as well as the other sources that comprise this source. Given the large number of emitting sources and the impact of those sources on the environment, the construction schedule and associated emissions over the construction timeline are essential to evaluate air quality and other impacts, indeed these PSD provisions are interdependent. Because emissions from construction differ from those once the sources are operating, the permit application must include schedules for both sets of activities. Without the construction schedule ADEC's proposed action fails to meet these regulatory requirements, it cannot issue a permit based on missing information and analysis. Moreover, without this essential information, the agency simply does not have factual information to conduct the required modeling analysis.

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sources from the one-hour nitrogen dioxide standard under certain circumstances; if a minor permit is issued under the "fast track" procedure, 18 AAC 50.542 limits the opportunity for public comment via a shortened initial public comment period of 15 days and of the public requests the full 30-day period, ADEC decides whether to grant more time (notably here, there are no criteria upon which ADEC must make such decisions).

[177] There will be some aboveground crossings of two water bodies, active faults, and the offshore portion of the Cook Inlet. FEIS at 2-13.

[178] *See also, generally, Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427 (2014) (holding that major sources of greenhouse gases are subject to the PSD program only if considered a major source of one or more criteria pollutants).

[179] *Cf. In the Matter of BP Exploration (Alaska), Inc. Gathering Center #1*, Order on Petition (April 20, 2007) (declining to overturn state permitting agency's "single source" determination in part because petitioner failed to demonstrate actual consequences on air quality as a result of the determination), available at https://www.epa.gov/sites/production/files/2015-08/documents/bpexploration_response2004.pdf, *aff'd sub nom. MacClarence v. EPA*, 596 F.3d 1123 (9th Cir. 2010).

[180] *Alabama Power* at 351. (emphasis added)

[181] 18 AAC 506.040(h)(12), adopting by reference 40 C.F.R.§ 52.21(n)(1).

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The PSD regulations provide for "issuing a comprehensive permit for construction projects that are to be completed in phases, thus avoiding a separate permit proceeding for each phase."[182] When construction projects are to be completed in phases, as is contemplated here, the PSD regulations allow a permitting agency to grant a comprehensive permit for a phased construction, thus avoiding a separate permit proceeding for each phase, if the permit provides the following:

> (1) independent BACT review of each phase of the project,
>
> (2) actual commencement of construction of each phase within eighteen months of the target date specified in the original application, with a variance procedure available only for the commencement date of the first phase of the project, and
>
> (3) avoidance of any interruption in the course of construction of any particular phase for longer than eighteen months.[183]

Thus, one option is for the AK LNG Project to see a comprehensive permit for construction of all the sources that are part of the PSD permit to avoid PSD permitting for each phase.

Regardless of whether a comprehensive permit or individual permits are issued, the PSD regulations require that a permittee commence construction within 18 months of receiving a permit. This requirement is in part to account for improvements in emission control technology and BACT determinations. Construction of the AK LNG Project is planned over a period of at least eight years, and ADEC's analysis did not take into consideration *when* emissions will occur from the Liquefaction plant, much less the numerous other emitting units that comprise the source. Therefore, ADEC's PSD permits for sources that are part of the AK LNG Project, including the Liquefaction plant, must include permit terms and conditions that reflect the 18-month requirement, and that no later than 18-months prior to commencement of construction of each source ADEC review, and modify as appropriate, the BACT determination. ADEC's review process must include public notice and an opportunity for public review comment.

C. The Proposed Permit Lacks BACT Emission Limitations for the Fugitive Emissions

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[182] *Id. See* 18 AAC 506.040(h)(8), adopting by reference 40 C.F.R. § 52.21(j)(4) ("For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source.")

[183] *Alabama Power* at 409 (further explaining that "Section 165 of the Clean Air Act states that no major emitting facility, on which construction is commenced … may be constructed in any clean air area unless PSD permitting requirements are met. For an industrial project that is to be constructed in stages, as over a period of years, the meaning of the phrase "construction is commenced" may determine whether and to what extent PSD preconstruction review applies. EPA has developed the practice of issuing a single, comprehensive PSD permit for an entire project with special conditions pertaining to each phase of construction.") *Id.*

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Once a facility's potential to emit exceeds the major source threshold, its fugitive emissions— or those that cannot "reasonably pass through a stack, chimney, vent or other functionally equivalent opening"[184] —are subject to BACT the same as all other emissions. "[A] a major emitting facility is subject to the requirements of section 165 for each pollutant it emits irrespective of the manner in which it is emitted."[185]

Neither AGDC's Application nor ADEC's efforts includes a BACT analysis for fugitive emissions from any source at the Liquefaction plant. Furthermore, as discussed above,[186] the Application and ADEC's analysis neither includes the Mainline Pipeline nor methane and VOC emissions from the pipeline. BACT should be required for fugitive emissions from the other AK LNG Project emitting sources as well. PSD applications must include the required analysis and include enforceable emission limits. For example, EPA Region VI's 2012 Statement of Basis for the Channel Energy Center in Pasadena, Texas—expressly lists "Fugitive Natural Gas emissions from piping components" as among the "devices . . . subject to th[e] GHG PSD permit" [187] and then proceeds to conduct a substantive BACT analysis for fugitive emissions, ultimately arriving at an enforceable emission limit. [188] Other greenhouse gas PSD permits incorporate similar limits.[189] Presumably because "the magnitude of fugitive emissions depends on how many . . . valves, connectors and pumps[ ] are present,"[190] BACT sometimes requires numeric limits on components in addition to a weight-based limitation.[191] The omission of any similar analysis or enforceable limit here renders the draft permit invalid.[192]

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[184] 18 AAC 50.990(40), 40 C.F.R. § 51.166(b)(20). Moreover, the PSD requirements apply to "apply to each regulated pollutant that a "major" source emits in "significant" amounts, e.g., 40 C.F.R. § 52.21(j). The regulations do not distinguish between stack and fugitive emissions for this purpose. *Masonite* at 582, citing 54 Fed. Reg. 48870 (Nov. 28, 1989).

[185] *Alabama Power* at 369.

[186] *Supra* at 20-22, Emissions from the Mainline Pipeline are incomplete and inaccurate.

[187] *See* Environmental Protection Agency Region VI, Statement of Basis for PSD Permit for the Channel Energy Center, Permit No. PSD-TX-955-GHG at 7 (Aug. 2012), available at https://archive.epa.gov/region6/6pd/air/pd-r/ghg/web/pdf/calpline_energy_sob.pdf.

[188] *See id.* at 25–26.

[189] *See, e.g.,* Environmental Protection Agency Region VI, Statement of Basis for PSD Permit for Tenaska Brownsville, Permit No. PSD-TX-1350-GHG (Oct. 2014), available at https://archive.epa.gov/region6/6pd/air/pd-r/ghg/web/pdf/tenaska-brownsville-revision-summary01232015.pdf; Environmental Protection Agency Region VI, Statement of Basis for PSD Permit for Thomas C. Ferguson Plant, Permit No. PSD-TX-1244-GHG (Nov. 11, 2011), available at https://archive.epa.gov/region6/6pd/air/pd-r/ghg/web/pdf/lcra_revisions_summary.pdf. *See also Consolidated Environmental Management, Inc.*, Petition Number VI-2010-05, VI-2011-06 and VI-2012-07, at 54 (E.P.A. Jan. 30, 2014) (declining to object to permit that "include[d] state-of-the-art ambient monitoring for fugitive emissions, such as additional monitoring and deposition gauges . . . intended to provide for information from which numeric emission levels can be calculated"), available at https://www.epa.gov/sites/production/files/2015-08/documents/nucor_steel_response_2012_zennoh.pdf.

[190] *See* Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56593, 56612 (Sept. 18, 2015) (Proposal).

[191] *See* Environmental Protection Agency Region VI, Statement of Basis for PSD Permit for Thomas C. Ferguson Plant, Permit No. PSD-TX-1244-GHG, 40 (Nov. 11, 2011), available at https://www.epa.gov/sites/production/files/2015-08/documents/nucor_steel_response2012.pdf (limiting facility to "520 gas/vapor valves, 1460 gas/vapor flanges and 3 gas/vapor compressors").

[192] *See Cash Creek Generation*, Petition No. IV-2010-4, at 11 (E.P.A. June 22, 2012) (Cash Creek II) (objecting to issuance of operating permit because the "BACT analysis that appeared in the permit application . . . omitted any discussion of . . . requirements serving as BACT for fugitive CO emissions"), available at https://www.epa.gov/sites/production/files/2015-08/documents/cashcreek_response2010.pdf.

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ADEC's analysis and draft permit only covers fugitive emissions from dust[193] and fails to evaluate and include BACT requirements for other fugitive emission sources. For example, the Liquefaction plant would include emissions sources characterized as "fugitive emissions from pipe flanges, valves, and valve stems."[194] Indeed, the Liquefaction plant would also include piping components, including connectors, pumps, and compressors. All of these components leak unless the Liquefaction plant uses leakless components.

BACT requires the maximum degree of control from a technically feasible technology unless there is a demonstrated adverse economic, energy or environmental impact. The BACT analysis should consider most effective control technology: leakless technology. While leakless technology is used to control leaks of toxic and hazardous gases, this is certainly not its only use. Leakless technologies are widely used in petrochemical facilities. They are not restricted to highly toxic or otherwise hazardous streams. Leakless technologies are used, for example, in every petroleum refinery in California's Bay Area Air Quality Management District (BAAQMD). Preventing leaks saves money and prevents adverse air quality impacts. It is a reasonable and technically feasible control technology.

ADEC provides no evidence in its proposal indicating that installing and operating leakless technology, LDAR, or remote sensing would cause uniquely excessive costs at the Liquefaction plant compared to other similar facilities. A widely used technology, such as leakless components or LDAR, cannot be eliminated on cost effectiveness grounds unless unique circumstances are demonstrated.[195] Conventional LDAR methods, used in many thousands of facilities throughout the petrochemical and refining industries, are cost effective to detect natural gas leaks, and should be cost effective here. The BAAQMD, for example, supervises LDAR programs at five refineries with over 200,000 regulated components, as well as chemical plants, bulk plants, and bulk terminals under its Regulation 8, Rule 18 (Reg 8-18).[196] Not only does ADEC fail to analyze BACT for natural gas leaks, it also fails to consider leaks of hazardous air

[193] FERC's FEIS explains that to minimize impacts on wind-erodible soils, AGDC developed a Project Fugitive Dust Control Plan that outlines dust control measures to be used as needed during construction and operation of the LNG Plant as discussed above in section 4.2.4. FEIS Volume 1, at 4-92, 4-118 ("AGDC's implementation of dust control measures outlined in the Project Fugitive Dust Control Plan, including: using dust control abatement measures as needed during construction and operation; applying water to affected unpaved roads and staging areas; applying approved dust suppressants such as calcium chloride or water/magnesium chloride mixture; and reducing speed limits on unpaved roads."). ADEC's proposed permit is inconsistent with the FEIS because fails to include provisions limiting dust suppressants to those that are "approved and also lacks provisions reducing speeds on unpaved roads." Moreover, ADEC's proposed permit conditions (10.1) only require fugitive dust control for five months (May through September), while there are no such temporal limitations in the FEIS. Further, ADEC fails to provide rationale for the temporal restriction.

[194] FEIS, Vol. 3 at 4-959.

[195] *See* NSR Workshop Manual at B.44, B.45.

[196] Bay Area Air Quality Management District, Regulation 8, Organic Compounds, Rule 18, Equipment Leaks, available at https://www.baaqmd.gov/~/media/dotgov/files/rules/reg-8-rule-18-equipment-leaks/documents/rg0818.pdf?la=en.

pollutants and refrigerant loses.[197] Further, there is no analysis of fugitive emissions from LNG storage and containment.[198]

D. The Proposed Permit Fails to Demonstrate Plant Will Comply with all Federal Standards

The statutory PSD program provides, inter alia, that no construction on a major emitting facility may be commenced after August 7, 1977 in an area designated under the PSD classification system unless:

> [T]he owner or operator of such facility demonstrates that emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of (C) any other applicable emission standard or standard of performance under this (Act.)

(42 U.S.C. § 7475(a)(3). This includes, notably, any applicable new source performance standard (NSPS).[199] Similarly, 42 U.S.C. § 7475(a)(4), requires the proposed facility to be subject to the best available control technology for each pollutant subject to regulation under the Act. Under the statutory definition of the term "best available control technology," it is stated that:

> In no event shall application of "best available control technology" result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 7411 (which defines the standards of performance for new stationary sources) of this title.

42 U.S.C. § 7479(3).[200]

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[197] FEIS Vol. 1 at 2-28(Following pre-treatment, three liquefaction-processing units, or trains, would liquefy the natural gas. AGDC would use the Propane Precooled Mixed Refrigerant (AP_C3MR™) Process, an Air Products and Chemicals, Inc. patented technology. In this process, the treated natural gas would be pre-cooled in successive stages of propane chilling. Subsequent cooling and liquefaction would occur by heat exchange against mixed refrigerant in the main cryogenic heat exchanger. Prior to entering the main cryogenic heat exchanger, the mixed refrigerant would be cooled/partially condensed. The refrigeration for this pre-cooling would occur by multiple stages of propane chilling. Each of the three liquefaction trains would include two refrigerant compression strings installed in parallel, driven by two natural gas turbines. The propane and mixed refrigerant would be cooled using air coolers. Fans would pull the air over tube bundles, in turn cooling within the tube bundles. Air-cooled LNG plants are influenced by air temperature variation. The air cooler inlet air-dry bulb design temperature would vary between a low ambient of 2°F and a high ambient of 61°F.).

[198] Furthermore, any suggestion by ADEC that the audio/visual/olfactory (AVO) leak detection method is the most effective method to detect leaks is simply wrong. Relying solely on AVO is not reasonable. The proposed plant is large and it is unreasonable to rely on an individual "sniff-test" during inspection rounds to detect all leaks from a variety of pollutants at a Liquefaction Plant.

[199] 40 C.F.R. § 52.21(j) (requiring that PSD program ensure that all "major stationary source[s] . . . meet each . . . applicable emissions standard and standard of performance under 40 CFR parts 60 and 61"). *See also Northern Plains Resource Council v. Environmental Protection Agency*, 645 F.2d 1349, 1352–53 (9th Cir. 1981) (A permitting authority "would clearly be acting contrary to the statutory PSD program in issuing a PSD permit to a facility which would produce emissions in excess of an applicable new source performance standard."). *See also* 18 AAC 50.040(h)(8), adopting by reference 40 C.F.R. § 52.21(j).

[200] *See* Parallel regulatory definitions of BACT, 18 AAC 50.040(h)(4), adopting by reference the definitions in 40 C.F.R. § 52.21(b)("(12) In no event shall application of best available control technology result in emissions of any

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ADEC's proposed action fails to contain an analysis of whether any NSPS apply, and if so, whether the proposed Liquefaction plant will meet those standards. Based on analyses and determinations by other permitting authorities for similar facilities, there appear to be several NSPS that might apply.[201, 202] ADEC is prohibited from issuing the permit for the proposed Liquefaction plant until such an analysis is conducted and a determination made that the BACT determinations will not exceed the NSPS standards.[203] Furthermore, as discussed in the Stamper Report, ADEC's proposed BACT limits for the diesel-fired units (the fire pump and the and auxiliary air compressor engine) are less stringent than the applicable NSPS standards.[204] Finally, the Order issued to the AK LNG Project by FERC indicates that "AGDC would implement various measures to reduce construction emissions, including … use of electric generators in compliance with New Source Performance Standards (NSPS) Subpart III."[205]

E. ADEC's Public Notice Suggests Its Proposed Approval includes Hazardous Air Pollutants, and There is no Supporting Analysis.

Additionally, while ADEC's notice for this proposed approval indicates the Liquefaction Plant is subject to the construction permitting requirements for hazardous air pollutants (HAPs), there is nothing in the proposal covering these pollutants and the requirements. ADEC's public notice explains that "[t]he project is also classified under 18 AAC 50.316 as a major source of Hazardous Air Pollutants for formaldehyde and ethylbenzene."[206] Similarly, the PreTAR explains that "AGDC submitted this analysis in support of their 1 May, 2018 air quality control permit application (AQ1539CPT01) submitted under the Prevention of Significant Deterioration (PSD) requirements listed in 18 AAC 50.*306 and the major source of hazardous air pollutant (HAP) requirements* listed in 18 AAC 50.316."[207] The rule cited by ADEC includes the requirements for preconstruction review for construction or reconstruction of a major source of hazardous air pollutants,[208] which suggests ADEC's proposed permit action is also intended to cover the CAA's hazardous air pollutant requirements, which is does not.

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pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61."); , 18 AAC 50.040(h)(4), adopting by reference the definitions in 40 C.F.R. § 52.21(b)("(16) *Allowable emissions* means the emissions rate of a stationary source calculated using the maximum rated capacity of the source (unless the source is subject to federally enforceable limits which restrict the operating rate, or hours of operation, or both) and the most stringent of the following: (i) The applicable standards as set forth in 40 CFR parts 60 and 61"); AAC 50.040(h)(8), adopting by reference 40 C.F.R. § 52.21(j) ("*Control technology review.* (1) A major stationary source or major modification shall meet each applicable emissions limitation under the State Implementation Plan and each applicable emissions standard and standard of performance under 40 CFR parts 60 and 61.")

[201] NSPS for Combustion Turbines Subpart KKKK, NSPS Subpart Db, NSPS Subpart IIII, NSPS Subpart Kb, NSPS Subpart OOOOa.
[202] *See, e.g.,* FEIS at 4-925 – 4-927.
[203] Additionally, the FEIS "determined that" several NSPS would be "applicable to one of more of the Project facilities," and ADEC did consider this information. *Id.* at 4-925 – 4-927.
[204] *See* Stamper Report at 31-33.
[205] FERC Order ¶ 202.
[206] Public Notice, State of Alaska, Department of Environmental Conservation Alaska Gasline Development Corporation Liquefaction Plant.
[207] PreTAR at 1.
[208] 18 AAC 50.316. Preconstruction review for construction or reconstruction of a major source of hazardous air pollutants.

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EPA established NESHAPs in 40 C.F.R. Parts 61 and 63 to control the emissions of Hazardous Air Pollutants (HAPs). NESHAP regulations include emission standards or work practices for specific types of equipment located at a HAP source. A HAP major source is a facility with a potential to emit 10 tpy or more of a single HAP or 25 tpy or more of a combination of HAPs. Both AGDC and ADEC conclude that the proposed Liquefaction plant is a major source of HAPs, and AGDC's permit application provides information on the NESHAPs that it determined applies. AGDC explains that:

> Information related to Liquefaction plant applicability of Part 63 NESHAPs is provided in Resource Report 9, Section 9.2.6.7, starting on page 9-94, and in RR9 Appendix H Project NSPS, NESHAPs and RMP Applicability Analysis, both included as Attachment 4. … See 18 AAC 50.316 discussion below for 63.5(d)(1)-(2) requirements. Please note that AK LNG has refined NESHAPs applicability analysis since RR9 was submitted to FERC in April 2017. The Project now believes requirements of 40 C.F.R. 63, subpart EEEE do apply to the Liquefaction plant, while those of 40 C.F.R. 63, subpart HH do not

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(a) Applicability. The owner or operator of a major source of hazardous air pollutants subject to a standard under 40 C.F.R. Part 63, adopted by reference in 18 AAC 50.040, must obtain a construction permit before (1) constructing a new major source of hazardous air pollutants subject to that standard; (2) reconstructing a major source of hazardous air pollutants subject to that standard; or (3) reconstructing a major source of hazardous air pollutants in a way that causes the source to become an affected source that is major-emitting under 40 C.F.R. Part 63 and subject to that standard.
Definitions. The term "administrator" as used in 40 C.F.R. 63.5(d) - (e), adopted by reference in 18 AAC 50.040, means "department" for the purposes of this section.
(c) Procedures for preconstruction approval. An application for a construction permit required under this section must be prepared and submitted in accordance with 40 C.F.R. 63.5(d), adopted by reference in 18 AAC 50.040. After receiving a complete application,
(1) the department will prepare a report that contains a preliminary decision to approve or deny the permit application; the department will make a decision to issue the permit only if the department determines that the criteria of 40 C.F.R. 63.5(e)(1), adopted by reference in 18 AAC 50.040, are met;
(2) if the department makes the preliminary decision to deny the permit application, the owner, operator, or permittee may submit additional information for the department to consider before the department makes a final decision, as follows:
(A) after consulting with the applicant, the department will specify dates by which the applicant must submit any additional information under this paragraph;
(B) within 60 days after receiving the additional information, the department will (i) make a preliminary decision to approve or approve with conditions; or (ii) take a final permit action and deny the permit application for cause; (3) if the department makes a preliminary decision to approve the permit application, the department will (A) prepare a draft permit; (B) provide at least 30 days for the public to comment, and upon its own motion or upon a request in accordance with 18 AAC 15.060, will hold a public hearing on the application as described in 18 AAC 15.060(d) - (h); and
(C) make available for public review the materials submitted by the applicant and a copy of the proposed permit in at least one location within the area known or expected to be affected by the stationary source as proposed; (4) if the department makes a decision to issue a final permit, the department will issue the permit consistent with AS 46.14.170.
(d) Permit Content. In a permit under this section, the department will include terms and conditions that (1) reference specific applicable requirements under each applicable subpart of 40 C.F.R. 63, adopted by reference in 18 AAC 50.040; (2) require reporting in accordance with 18 AAC 50.235 - 18 AAC 50.240; and (3) require payment of fees in accordance with 18 AAC 50.400 - 18 AAC 50.420.
(e) Notification. For each notification that the owner or operator is required to send to the administrator under 40 C.F.R. 63.9, adopted by reference in 18 AAC 50.040, the owner or operator shall also send a copy of the notification to the department.

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apply to the Liquefaction plant. This differs from Table 9.2.6-6 of Resource Report 9, which indicates applicability of these two subparts is "TBD" (to be determined). AK LNG provided the Department a revised version of Table 9.2.6-6 in response to response RFI-538-014 submitted in response to the Department's March 6, 2018 incompleteness finding for the GTP construction permit application.[209]

The Application further remarks that "18 AAC 50.316(a) is the process in the Alaska State Implementation Plan for meeting 40 CFR 63.5(d)(1)-(2) requirements related to application for approval of construction of a HAP-Major Source".[210]

Contrary to the statement made in the Application, ADEC's authority for acting on applications requesting approval for construction of major sources of HAPs is not under the SIP. Rather, ADEC's authority for acting on the NESHAP and MACT requirements falls under section 112 of Act, and is a result of EPA's action on ADEC's Operating Permits Program, which included action on the State's Section 112(l) Program Submittal.[211] EPA's action identified the authority found in the Alaska regulations, which it approved and found met the requirements for adequate legal authority for Alaska to implement and enforce section 112 approval.[212]

The NESHAP identified by AGDC is 40 C.F.R. 63, subpart Eeee are the National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non–Gasoline), which "establishes national emission limitations, operating limits, and work practice standards for organic HAPs emitted from organic liquids distribution (OLD) (non-gasoline) operations at major sources of HAP emissions."[213] This NESHAP "also establishes requirements to

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[209] Alaska LNG, Alaska LNG Liquefaction Construction Permit Application, Project Information Form Attachment 1, Information Reference Table for Alaska LNG Liquefaction Plant (March 2018), Citation 63, PDF at 4.
[210] *Id.* at 5.
[211] 61 Fed. Reg. 49091, 49094 (Sept. 18, 1996)(EPA's proposal explained, "[a]uthority for section 112 implementation. Except as discussed below in section B.1.iii. and the section proposing action on Alaska's section 112(l) submittal, Alaska has demonstrated adequate legal authority to implement and enforce section 112 requirements through the title V permit. Alaska has incorporated by reference most of the regulations that have been promulgated by EPA under section 112 of the Act that may affect Alaska sources. See 18 AAC 50.040(b) (relevant standards under 40 C.F.R. part 61); 18 AAC 50.040(c) (relevant standards under 40 C.F.R. part 63); AS 46.14.130(a) and 18 AAC 50.300 to 50.322
preconstruction review of major sources of hazardous air pollutants ("HAPs").") EPA's final action on ADEC's authority to implement the Section 112 requirements further explained that, "In the September 18, 1996, Federal Register notice, EPA noted that Alaska lacked authority to implement several section 112(l) requirements, but believed that these deficiencies were not so serious as to warrant disapproval. 61 FR 49095. Alaska commented that the September 17, 1996, final version of the adopted State rules included the adoption by reference of 40 C.F.R. § 61.150 and 40 C.F.R. § 61.154 and asked that EPA remove the specific interim approval conditions related to these provisions. EPA agrees that the adoption of these two provisions remedies the deficiencies regarding implementation and enforcement of the asbestos NESHAP for waste disposal and active waste disposal sites.[FN1] Alaska has still not adopted, however, the provisions of 40 C.F.R. part 61, subpart I (radionuclide NESHAP for facilities licensed by the Nuclear Regulatory Commission). Therefore, the State still lacks sufficient authority to implement all applicable section 112 requirements for title V sources in Alaska. As such, EPA concludes that the Alaska program must be granted interim rather than full approval because of this deficiency.") *See also* 61 Fed. Reg. 64463, 64465 (Dec. 5, 1996)(EPA's Final Approval in Part and Disapproval in Part, Section 112(l) Program Submittal).
[212] *Id.*
[213] 40 C.F.R. § 62.2330.

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demonstrate initial and continuous compliance with the emission limitations, operating limits, and work practice standards."[214] Other NESHAPs may apply.[215]

Furthermore, ADEC's Preliminary TAR acknowledges that the "project is also classified under 18 AAC 50.316 as a major source of HAPs for formaldehyde and ethylbenzene,"[216] but it provides no analysis to determine what or whether any hazardous air pollutant standards apply, and whether any other HAPs are emitted. Therefore, if ADEC's proposal is intended to cover the construction permitting requirements for HAPs, it does not.

V. ADEC's Proposed BACT Determinations Are Flawed and Incomplete and ADEC's Proposed Emission Limitations Fail to Reflect BACT

The AGDC's proposed Liquefaction plant - and the Alaska LNG Project - must comply with the PSD BACT requirements as it is located in an attainment or unclassifiable area.[217] The Clean Air Act requires states with regions in attainment of the national ambient air quality standards to guard their attainment standards by implementing the PSD provisions found in sections 160 to 165 of the Clean Air Act. As Ms. Stamper's report explains, a final PSD permit issued by ADEC must impose emission limits reflective of BACT for each regulated air pollutant that Alaska LNG Project has the potential to emit in significant amounts,[218] which include nitrogen oxides (NOx), carbon monoxide (CO), volatile organic compounds (VOCs), sulfur dioxide (SO_2), particulate matter (PM) including PM_{10} and $PM_{2.5}$, and greenhouse gases (GHG).[219, 220] The PSD regulations define best available control technology as follows:

> [A]n emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement

[214] *Id.*
[215] For example, other LNG facilities determined that the following apply: 40 C.F R. § 63, SUBPART ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE), applies to all of the proposed diesel-fired engines. Subpart CCCCCC – Gasoline Dispensing Facilities at Area Sources. Subpart JJJJJJ – Area Source Boiler MACT- Industrial, Commercial and Institutional boilers and process heaters located at area sources of HAPs. NESHAP for Combustion Turbines Subpart YYYY.
[216] PreTAR at 2. Furthermore, the draft permit defines the hazardous air pollutant standard acronyms (NESHAP and MACT), but fails to include any of the requirements for these standards in the draft permit. Draft Permit at iii.
[217] Alaska Nonattainment/Maintenance Status for Each County by Year for All Criteria Pollutants, EPA (Oct. 31, 2020), available at https://www3.epa.gov/airquality/greenbook/anayo_ak.html.
[218] 40 C.F.R. § 52.21(j)(2), incorporated by reference into Alaska Rules at 18 AAC 50.040(h)(8).
[219] ADEC's Preliminary September 11, 2020 Technical Analysis Report (TAR) at 2.
[220] Stamper Report at 3.

> methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

40 C.F.R. § 52.21(b)(12), incorporated by reference into Alaska Rules at 18 AAC 50.040(h)(4). Thus, BACT requires an intensive analysis designed to ensure that the facility selects the most stringent available control technology unless it meets the high bar of showing that such technology is not technologically or economically feasible. Failure to provide a reasoned justification for applying a less stringent technology is grounds for federal intervention in ADEC's permitting decisions.[221] In promulgating the federal BACT definition[222] upon which the Alaska regulation is based, "Congress intended BACT to perform a technology-forcing function."[223] ADEC has a legal obligation to follow the regulatory requirements in its SIP, so that consistent with the purposes of the PSD program as outlined by Congress, its permitting decision:

- Protects health and welfare,
- Preserves and protects the air quality in Alaska's national parks and preserves, and national wilderness areas,
- Insures that economic growth will occur in a manner consistent with the preservation of existing clean air resources, and
- Assures that any decision to permit increased air pollution in any area to which this section applies is made only after careful evaluation of all the consequences of such a decision.[224]

In other words, ADEC must not only follow the regulations, but must do so furthering the goals and purposes of the PSD program. As detailed in Ms. Stamper's Report, ADEC's proposal ignores data, fails to accurately justify assumptions, and misapplies the regulations, which results in allowing the sources at the proposed Liquefaction plant to avoid the required BACT analysis. ADEC's proposal fails to require proper, up-to-date technology to limit the pollutant emissions. By allowing the permit applicant to avoid its legal responsibilities under the PSD Program and escape the legally compliant BACT analysis, ADEC is placing the Class I areas and impacted community members at risk of great harm. The purpose of the PSD permitting process is to

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[221] *See ADEC* at 490, 502, ("Congress . . . vested EPA with explicit and sweeping authority to enforce CAA 'requirements' relating to the construction and modification of sources under the PSD program, including BACT" and "EPA has supervisory authority over the reasonableness of state permitting authorities' BACT determinations and may issue a stop construction order, under §§ 113(a)(5) and 167, if a BACT selection is not reasonable.").
[222] 42 U.S.C. § 7479(3).
[223] EPA, Transmittal of Background Statement on "Top-Down" Best Available Control Technology (BACT) (June 13, 1989) at 5 ("EPA Background Statement on BACT"), available at https://www.epa.gov/sites/production/files/2015-07/documents/topdawn.pdf.
[224] *Id.* Therefore, the "basic purpose" of the PSD program is "simply put, to keep air clean." *Roosevelt Campobello Int'l Park Comm'n v. EPA,* 684 F.2d 1034, 1036 (1st Cir. 1982).

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protect the public health and welfare by ensuring that economic growth occurs in a responsible manner.[225] ADEC must redo its analysis, correct the errors, follow the regulatory requirements, and repropose this permit to ensure that the National Parks and Preserves in Alaska and public health are protected.

A. BACT for NOx for Compressor Turbines (EU 1-6) and Power Turbines (EU7-10)

1. ADEC Failed to Obtain, Consider and Make Available the Necessary Turbine Details.

The AGDC's proposed Liquified Natural Gas Plant will have several natural gas-fired turbines and neither the AGDC permit application nor the draft permit identify the make and model of the gas turbines to be installed. ADEC's Technical Analysis Report states that the make and model of these turbines are "yet to be selected."[226] As explained in Ms. Stamper's report and supported by examples, knowing the turbine make and model is important to be able to accurately project potential emissions, flue gas exhaust characteristics, and to analyze and set best available control technology (BACT) emission limits.[227] Ms. Stamper's report shows that the two potential turbine options for the large compressor turbine envisioned by the AGDC permit application have very different levels of NOx emission rates.[228] Furthermore, the net heat rate can also vary between turbine models, which can impact the greenhouse gas (GHG) BACT determination. Furthermore, the capacity of the turbines are also usually identified in the permit – i.e., horsepower rating for compressor turbines and megawatt output rating for power generating turbines. In permits for combined cycle units, the generating capacity of the heat recovery steam generator is specified and, if duct firing is to be included, the heat input in million British Thermal Units per hour (MMBtu/hr) (including for duct firing, if a unit will be so equipped) is specified along with the megawatt generating capacity of the generator with duct firing. Ms. Stamper's report cites to and includes examples of several such permits issued by other states that specifically identify the make and model and also power (horsepower or megawatt rating) of turbines to be installed.[229]

The specific make and model of turbines is necessary to evaluate BACT and set BACT emission limits, particularly for NOx, CO, and GHG. The Draft Permit for the Liquefaction plant uses non-factual "assumptions" regarding the combined cycle power generation turbines, and

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[225] 42 U.S.C. §7470, *See also* "What is PSD's Purpose," EPA, (Feb. 2019), https://www.epa.gov/nsr/prevention-significant-deterioration-basic-information.
[226] *Id.* at 2 and 19.
[227] NSR Workshop Manual states that "the technical specifications may be considered the core of the permit" and that identification of the emission unit "usually includes a brief description of the source or type of equipment, size or capacity, model number or serial number, and the source's identification of the unit," at H.5. For natural gas-fired turbines, identification of the make and model of the turbine is relevant to the BACT analysis for nitrogen oxides (NOx), carbon monoxide (CO), volatile organic compounds (VOCs), greenhouse gases (GHG), and other pollutants, as well as potential to emit of the turbines.
[228] Stamper Report at 4.
[229] *Id.* at 4-5.

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lacks information on the make and model, horsepower or megawatt rating, as well as hourly heat input. ADEC's Draft Permit similarly lacks information for the heat recovery steam turbine generator, where the MW rating of the must be defined and, if it will be supplemented with duct firing, the heat input to the duct firing must also be specified in the permit as well as the increased generating capacity. This information is essential for ADEC to accurately determine BACT as well as take into account specific flue gas characteristics of the turbines and the level of emissions in the air dispersion modeling required by the PSD regulations.

2. There is no Justification for the NOx Baseline Emission Rate Used in ADEC's Cost Effectiveness Analysis for NOx Controls.

The Liquefaction plant will use six simple cycle natural gas-fired combustion turbines (EU1-6) for the three compressor LNG trains at the Liquefaction plant, with two turbines used for each LNG train.[230] The Liquefaction plant will use four natural gas-fired combustion turbines operated in a combined cycle mode for power generation (EU 7-10).[231] ADEC has proposed to only require dry low NOx (DLN) combustors to meet a 9 parts per million by dry volume at 15% oxygen NOx limit (ppmv @ 15% O_2) as BACT for NOx at all of these turbines.[232] ADEC rejected the NOx control of DLN combustors along with selective catalytic reduction (SCR) to meet a NOx limit of 2 ppmv@ 15% O_2 as not cost effective, despite acknowledging that several similar large turbines have installed such controls as BACT. There are several flaws with the ADEC BACT analyses, as discussed in Ms. Stamper's report.

First, to determine cost effectiveness of a particular control technology or technique at an emissions unit, one must know the baseline emissions rate of that unit to assess the amount of pollution that will be reduced with a particular control.[233] ADEC's baseline emissions rate assumption differs from information in the permit application and while ADEC asserts it followed the permittee's approach, it did not: For the compressor turbines, ADEC considered a NOx rate of 15 ppmv, while AGDC used a 25 ppmv NOx rate. ADEC provides no basis for its lower baseline emissions rate assumption.[234] For the power generating turbines, both ADEC and AGDC assumed a 15 ppmv NOx baseline rate. This assumed baseline NOx rate is unjustified because AGDC has not yet selected a vendor or model of the power turbines to be used at the Liquefaction plant and the draft permit does not require a certain make or model of compressor turbine.[235] Additionally, as discussed in detail in Ms. Stamper's report, AGDC's use of a 25 ppmv@ 15% O_2 NOx baseline for evaluating costs of additional controls at the compressor turbines makes much more sense for a base case emission rate for both the compressor turbines and the power turbines, as compared to ADEC's assumption of a 15 ppmv@ 15% O_2 NOx baseline.[236] Therefore, "[g]iven that the draft permit has not specified a certain turbine make and

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[230] PreTAR, Appendix B at 2.
[231] *Id.* at 19.
[232] PreTAR (Sept. 11, 2020), Appendix B at 6 and 24.
[233] Stamper report at 6.
[234] *Id.*
[235] *Id.* at 7.
[236] *Id.* at 6-7.

model and that AGDC has not proposed a turbine make and model, it is reasonable to assume a NOx baseline of 25 ppmv@ 15% O_2."[237]

Finally, to illustrate the importance of this information in calculating emissions, Ms. Stamper's report calculates a NOx emissions baseline for the compressor turbines and for the power turbines based on a 25 ppmv baseline NOx rate. Ms. Stamper's calculated baseline of NOx emissions for the compressor turbines was 487.5 tons per year (tpy) per turbine,[238] which is much higher than ADEC's NOx baseline of 281.8 tpy.[239]For the power generating turbines, Ms. Stamper's calculated NOx baseline was 168.2 tpy per turbine, which is significantly higher than ADEC's 104 tpy NOx baseline.[240]

3. AGDC Assumed Too High an Interest Rate and Too Short a Life of Controls in its NOx Control Cost Effectiveness Analysis.

AGDC apparently assumed both a 7% interest rate and a 5.5% interest rate, along with a 20-year life of controls, in is cost effectiveness analysis of selective catalytic reduction (SCR) and DLN combustors for the compressor turbines and the power turbines.[241] This was not made clear in AGDC's March 2018 BACT analysis, because the details of the cost calculations in Appendix B of the company's BACT analysis were claimed as "Trade Secret in accordance with AS 46.14.520."[242] Given that the make and model of the combustion turbines has not been selected by AGDC nor required by the permit, it does not seem justified to withhold the detailed BACT cost effectiveness calculations for the turbines as trade secrets. Although the details of AGDC's cost effectiveness analyses were not provided in its permit application, ADEC's Technical Analysis Report states that AGDC used a 7% interest in its cost calculations that were based on the 6th edition of EPA's Control Cost Manual and that AGDC used a 5.5% interest rate in its cost calculations that were based on the 7th edition of EPA's Control Cost Manual.[243] ADEC revised the SCR cost analyses to be based on the current bank prime interest rate of 3.25% and to be based on an SCR life of 25 years for both the compressor turbines and the power turbines.[244] EPA's SCR Cost Spreadsheets that it has made available with its recent updates to its Control Cost Manual[245] recommend using the current bank prime lending rate in amortizing capital costs of controls, and it is currently 3.25%.[246] EPA's SCR Control Cost Manual also indicates that an SCR at an industrial boiler should have a useful life of 20-30

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[237] *Id.*
[238] *Id.* at 8.
[239] PreTAR, Appendix B at 7 (Table 3-5).
[240] Stamper Report at 8.
[241] ADEC's Preliminary September 11, 2020 TAR, Appendix B at 6 and at 23.
[242] *See* cover page for Appendix B to Attachment 6, BACT Analysis, April 30, 2018 of AGDC's Alaska LNG Application.
[243] ADEC's Preliminary September 11, 2020 TAR, Appendix B at 6 and at 23.
[244] *Id.* at 7 and 24.
[245] *See* EPA's SCR Cost Calculation Spreadsheet available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[246] *See* Board of Governors of the Federal Reserve System, Selected Interest Rates (Daily) – H.15 https://www.federalreserve.gov/releases/h15/.

years.[247] However, for a power plant, EPA states that an SCR should have a useful life of 30 years or more.[248]

ADEC's assumptions for interest rate and life of SCR at the compressor turbines are consistent with the current (7th edition) version of EPA's Control Cost Manual, although it would be more reasonable to assume a life of SCR of 30 years for the compressor turbines for a few reasons. First, AGDC has stated that the expected life of the entire operation is 30-years (i.e., Prudhoe Bay major gas sales operations are expected to have a 30-year life).[249] Second, AGDC has stated that the compressor turbines would be operating at 100% load during normal operations, rather than at variable loads, and such steady state operation would be similar to operations at a base load power plant.[250] EPA states that SCR at power plants is expected to have a useful life of 30 years or more. Thus, it would be more reasonable to assume SCRs at both the compressor turbines and the power turbines would last the 30-year life of the LNG plant.

In terms of using an older edition of EPA's Control Cost Manual, EPA revised its Control Cost Manual in 2019, including its chapter on SCR through an extensive notice and comment process, and that is the version that AGDC and ADEC should be using in the BACT cost effectiveness calculations as it is the most up-to-date with current costs for SCR.

4. AGDC and ADEC Assumed Too High a Cost of Ammonia in the SCR Cost Effectiveness Calculation.

ADEC stated that it did not revise the cost of ammonia that AGDC used in its cost calculations. Specifically, ADEC used a cost for aqueous ammonia of $2.24/gallon ($0.30/pound) and cited to the "Weekly Fertilizer Review, 4/2015." As Ms. Stamper explains in her Report, EPA's SCR Control Cost Manual chapter assumes a much lower cost for aqueous ammonia of $0.293/gallon, based on the average for 2016 from the U.S. Geological Survey's Minerals Commodities Summaries, for which EPA provided a weblink.[251] ADEC did not provide any weblink or other citation for its assumed cost of aqueous ammonia from the Weekly Fertilizer Review. Further, given recent changes in fuel prices, a more recent cost basis for ammonia should have been used.[252]

In addition, Ms. Stamper explains that use of anhydrous ammonia in the SCR, rather than aqueous ammonia, should have been evaluated in the cost effectiveness calculations. EPA's Control Cost Manual chapter for SCR states that anhydrous ammonia is more commonly used for SCR controls because it is the least expensive.[253] Indeed, EPA has acknowledged that 80% of EGUs operating SCR use ammonia (and not urea, which is another available SCR reagent) as the reagent for the SCR and, of those, anhydrous ammonia is used over aqueous ammonia by a

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[247] *See* EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 80.
[248] *Id.*
[249] *See* April 14, 2017 Resource Report No. 1 General Project Description at 1-92, at pdf page 180 of Attachments 1 through 3 of permit application.
[250] *See* 2018 Application Attachments 4 and 5 at pdf page 229.
[251] *Id.* at pdf page 82. Stamper Report at 9.
[252] Stamper Report at 9.
[253] *Id. See also* EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 82.

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ratio of 3 to 1.[254] Aqueous ammonia has the highest operating costs because of the cost of transportation.[255] Thus, ADEC should have evaluated the costs of using anhydrous ammonia in the cost effectiveness of SCR for the compressor turbines. The U.S. Geological Survey Minerals Commodities Report has the average cost for 2019 at $230/ton.[256] Although EPA's SCR cost calculation spreadsheet made available with the revised 2019 SCR chapter of the Control Cost Manual does not specifically provide for the use of anhydrous ammonia, the spreadsheet can readily be revised to account for the use of anhydrous ammonia as is discussed further below.[257]

5. AGDC and ADEC Assumed Too High of a Cost for Electricity, Given that the Liquefaction plant Will Be Equipped with Power Generating Turbines.

As presented in Ms. Stamper's Report, in its SCR cost analyses, both AGDC and ADEC assumed a cost of electricity of $0.16/kW-hr, which apparently is the average cost of electricity for industrial customers in Alaska.[258] For SCR cost effectiveness evaluations at utilities, EPA's Control Cost Manual states that the cost for auxiliary power is "the cost to the power plant to generate its electricity, or busbar cost."[259] While it is not clear what the cost is for AGDC to generate its electricity with its power turbines, it very likely will be significantly lower than the average electricity cost for industrial consumers in Alaska. EPA's SCR cost spreadsheet uses a default cost of $0.0361/kWh for electricity cost and states that the user should enter the actual value for electricity cost, if known.[260] Thus, AGDC and ADEC should use the actual cost for generation of auxiliary power at its Liquefaction plant in the SCR cost analyses from its planned power generating turbines which presumably should just equate to the fuel cost per kilowatt-hour produced. If that cost is currently unknown, which appears to be the case given all the uncertainties associated with plant design, the EPA default cost of $0.0361/kWh should be used.

6. Revised Cost Effectiveness Calculations for NOx Controls at the Liquefaction Compressor Turbines and Power Turbines.

To address the deficiencies discussed above, Ms. Stamper prepared revised cost analyses of NOx controls for the compressor turbines and the power turbines using EPA's SCR cost spreadsheet made available with its 2019 revised version of its SCR Chapter of its Control Cost Manual.[261] Her report provides details on the inputs for her calculations.[262]

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[254] *See* EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 5.
[255] *Id.*
[256] U.S. Geological Survey, Minerals Commodities Summaries (2020), at 116, available at https://www.usgs.gov/centers/nmic/mineral-commodity-summaries.
[257] Stamper Report at 9-10.
[258] ADEC's Preliminary September 11, 2020 TAR, Appendix B at 7 and at 23.
[259] EPA, Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, at 33 (fn 17), available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[260] *See* EPA's SCR Cost Calculation Spreadsheet at Data Inputs tab, row 56, available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[261] *See* EPA's SCR Cost Calculation Spreadsheet available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[262] Stamper Report at 10 and 15.

Ms. Stamper's report estimates the cost effectiveness for an SCR system at each compressor gas turbine that will reduce NOx from the worst case NOx baseline rate of 25 ppmv down to 2 ppmv, which reflects a 92% reduction in NOx across the SCR, to be $3,483/ton of NOx removed.[263] Ms. Stamper's report estimates the cost effectiveness for an SCR system at each combined cycle power turbine to reduce NOx from 25 ppmv down to 2 ppmv to be $5,308/ton.[264] Ms. Stamper provides ample support that 92% NOx reduction can be achieved with an SCR system, and her report provides numerous examples of simple cycle and combined cycle turbines being required to meet NOx BACT limits in the range of 2.0 (for combined cycle turbines) to 2.5 ppmv (for simple cycle turbines).[265] Her report explains that there are readily implementable options to address high exhaust temperatures of simple cycle turbines that could be used to optimize the NOx removal efficiency of an SCR system at a simple cycle gas turbine.[266] Therefore, AGDC statements regarding concerns regarding exhaust temperature can be addressed.[267]

In its BACT discussion for the compressor turbines, AGDC suggests that the 2 ppmv NOx rates have been achieved with SCR at gas turbines "only while under very stringent operational control," and AGDC points to SCR difficulty at Alaska sources "in maintaining uniform ammonia injection rates due to varying ambient temperatures and load ranges."[268] However, Ms. Stamper's report points out that SCR has been required as BACT and installed on numerous simple cycle gas turbines that operate as peaking plants (i.e., with varying load ranges) in the United States, that SCR has been successfully implemented in cold climates including other facilities in Alaska, and provides detailed examples demonstrating that in many cases, the NOx limit imposed with SCR was somewhat higher than 2 ppmv, but compliance was required on a very short-term basis with NOx emissions being monitored with continuous emissions monitoring systems (CEMs).[269] It is also important to point out that AGDC evaluated cost effectiveness of SCR to meet a 2 ppmv NOx limit,[270] and it appears that AGDC obtained a vendor quote, which presumably included a NOx emission rate guarantee, for the SCR systems. In records NPCA obtained on December 4, 2020 from its freedom of information request submitted to ADEC for the FLM communications, the FLMs reference the "vendor quote obtains by AK LNG for their turbines."[271] The FLM communications further indicate they found several

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[263] *Id.* at 16 (Table 6).
[264] *Id.* (Table 7).
[265] *Id.* at 12-15.
[266] *Id.* at 11-12.
[267] Additionally, the actual exhaust temperature is unknown because AGDC has not specified a make or model of compressor turbine to be installed.
268 Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 18.

[269] Stamper Report at 12-15,
[270] Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 22.
[271] Email from Andrea Stacy to Dave Jones, "NOx BACT questions for ADEC," (Oct. 26, 2020) ("I am sharing our initial technical evaluation of the AK LNG NOx BACT analysis to aid in the discussion of this topic," And in comparing the Liquefaction plant to the Agrium proposed facility, she explains that "The Agrium Solar turbines are much smaller units than the proposed turbines at the AK LNG liquefaction facility. In general, the "economy of scale" concept indicates that the smaller the unit, the lower the potential emissions reduction and the less cost-effective a measure becomes on a $/ton basis. While we don't have a cost evaluation for SCR on the Agrium turbines (a cost analysis is not required if a top-level control is selected), it is likely more expensive per ton of NOx removed to control the Agrium turbines than the AK LNG liquefaction facility turbines, calling AGDC's economic feasibility determination into question." (Email and attachment enclosed)

errors in AGDC's BACT analysis, revised the analysis and included the corrected analysis with their communication dated October 26, 2020.[272] Therefore, the FLM consultation was occurring *during* the public comment period on this proposed permit and not prior to it as required by the PSD regulations, which is discussed later in our comments.

SCR has been required as BACT for numerous simple cycle and combined cycle turbine, whether used for power generation or as compressor turbines and including turbines at LNG facilities.[273] In fact, ADEC has recently proposed to require SCR to meet NOx BACT at six power generating turbines at the nearby Agrium plant.[274] Thus, the cost of installing SCR to meet BACT at the compressor turbines and power turbines of the Liquefaction plant must be considered reasonable to meet BACT. As stated in EPA's Control Cost Manual, "[i]n the absence of unusual circumstance, the presumption is that sources within the same category are similar in nature, and that cost and other impacts that have been borne by one source of a given source category may be borne by another source of the same source category."[275] AGDC has not indicated any unusual circumstances at its compressor turbines and power turbines that would negate SCR from being required to meet BACT, other than the turbines being located in Alaska. That argument is without merit, given other facilities using SCR in Alaska and given that ADEC is proposing to require combustion turbines at the nearby Agrium facility to install SCR to meet NOx BACT.

B. ADEC Fails to Follow the Regulatory Requirements in Proposing BACT for Carbon Monoxide (CO) for the Natural Gas-fired Compressor Turbines and the Power Turbines

As outlined in Ms. Stamper's Report, AGDC's proposed CO BACT limit at both the compressor turbines and at the power turbines reflects the *least* stringent emission limit that has been required as BACT for CO with oxidation catalyst at gas-fired turbines in the EPA's RACT/BACT/LAER Clearinghouse.[276] While ADEC proposed a lower CO limit, rather than follow the proper BACT methodology and evaluate the lowest CO limit achievable with catalytic oxidation at gas-fired turbines, ADEC simply took the average of the CO emission limits required for this control at gas turbines and proposed a CO BACT emission based on an average

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[272] *Id.* ("We found several errors in AGDC's BACT analysis and revised the analysis to correct these errors (attached). We understand that the Department also revised the AGDC analysis to update the bank prime interest rate and the PTE assumptions; however, we found additional assumptions that impact the direct annual costs. It also appears that in their 6th edition estimates, the applicant double counted some TCI fees by including CCM default calculations for line items that were also included in the vendor quote. All revisions to the cost analysis and the basis for our analysis assumptions are documented in the attached spreadsheets along with the "LF_ARD_analysis_assumptions_review_notes.docx" document. Our results indicate that SCR is much more cost-effective for the four power generation turbines and six compressor turbines at the LF facility than what AGDC's analysis suggests.)

[273] Stamper Report at 11-17.

[274] See Preliminary ADEC Technical Analysis Report for Construction Permit AQ0083CPT07 issued to Agrium U.S., Inc., for the Kenai Nitrogen Operations, November 20, 2020, Appendix B: Best Available Control Technology (BACT) at 7-8.

[275] EPA, New Source Review Workshop Manual, October 1990, at B.29.

[276] Stamper Report at 18.

for both the compressor turbines and the power turbines.[277] This approach, and the others presented in Ms. Stamper's Report is inconsistent BACT regulation because it is not based on the maximum degree of emission reduction that can be achieved considering the costs of controls and other environmental and energy factors. The goal of the BACT analysis is to be technology-forcing and ensure the maximum degree of emission reduction is achieved, and this is best achieved through the top-down BACT review. ADEC must follow the regulatory process and impose a CO BACT limit reflective of the maximum degree of CO emission reduction achievable at the Liquefaction plant compressor turbines and at the power turbines.

C. BACT for GHG from the Compressor Turbines (Emission Units 1-6) and the Power Turbines (Emission Units 7-10)

ADEC has proposed to find that BACT for GHG emissions from the compressor turbines and the power turbines would be based on good combustion practices and low carbon fuels to meet a GHG limit of 117.1 lb/MMBtu on a 3-hour average basis.[278] As discussed in Ms. Stamper's Report, the proposed GHG limit does not reflect the maximum degree of GHG emission reductions that could be achieved at either the compressor turbines or the power turbines.[279]

1. ADEC's BACT Analysis Improperly Eliminates Carbon Capture and Sequestration

ADEC's analysis considered the information submitted by AGDC on carbon capture and sequestration (CCS) for its combustion turbines. As Ms. Stamper explains in detail, there are several issues with using the information AGDC submitted. First, it fails to include any site-specific costs, and is based on analyses for other facilities.[280] Moreover, as Ms. Stamper further notes, ADEC fails to explain what methodology was used to derive the cost estimates for the Liquefaction plant from the other studies.[281] ADEC's proposal also lacks justification explaining why the information from the other facilities is comparable to the Liquefaction plant. Moreover, the economic analysis and amount of GHG emissions reduced differ in the ADEC and the AGDC analyses. Therefore, the data ADEC relies on is different from what AGDC used. NPCA submitted requests to ADEC for this information, and did not receive it. Therefore, NPCA is unable to review on comment on ADEC's proposal because ADEC has neither provided nor justified the actual cost data it relies on (e.g., capital cost of CCS for the Liquefaction Plant, the transportation costs and assumptions, the operational costs and assumptions, and any other costs). Furthermore, ADEC failed to provide: the details regarding GHG reduction calculations and the cost analysis for CCS at the Golden Pass LNG project that it cites – and relies on - in its Technical Analysis Report.

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[277] *Id.*
[278] ADEC's Preliminary September 11, 2020 TAR, Appendix Bat 19 and at 36.

[279] Stamper Report at 19-29.
[280] *Id.* at 19-20
[281] *Id.* at 20-21.

Moreover, given the site-specific considerations of CCS, it is unreasonable for ADEC to first rely on a study for the GTP more than 800 miles away from the proposed Liquefaction plant, and rely on a second study that appears to be have been done for a Texas facility. ADEC cannot conclude that CCS is not cost effective for the AK LNG Project without a site-specific evaluation of this highly effective GHG control. Moreover, as Ms. Stamper presents, there are features at the proposed location for the Liquefaction plant that may be a prime area to consider for sequestration of carbon.[282] Neither AGDC nor ADEC perform the required study to examine sequestration at the Liquefaction plant site.[283] Thus, ADEC's evaluation of CCS for the Liquefaction plant is wholly deficient because detailed design studies have not been done to assess the feasibility of CCS, and ADEC has no basis to conclude CCS is not cost effective.

2. ADEC's Consideration of the Use of Electric Compressors Fails to Follow the Regulatory Requirements

The EPA has articulated an exception to the BACT requirement known as the "redefinition of the source" doctrine, and under this doctrine, a permitting authority may (but is not required to) eliminate from the BACT analysis an otherwise available control option that would disrupt the basic business purpose of the proposed facility.[284] In order to exercise this discretion, the permitting authority must first take a 'hard look' at which design elements are 'inherent' to the applicant's purposes and which design elements could possibly be altered to achieve pollutant reductions while maintaining the facility's basic business purpose. ADEC's incorrectly suggests that consideration of the use of electric compressor would redefine the source.

Another top BACT control option for the compressor turbines is the use electric turbines, which would eliminate all GHG emissions as well as other pollutant emissions from the turbines. Indeed, use of electric compressor turbines is the top level BACT control option for all pollutants. AGDC did identify use of electric motors as a GHG BACT control. However, AGDC eliminated this control from further consideration for the compressor turbines because, as Ms. Stamper's Report explains, AGDC incorrectly asserted that the use of electric turbines would redefine the source given that the Liquefaction plant would not be connected to the local electrical power grid.[285] In conducting its analysis, ADEC failed to take a "hard look" at AGDC's business purpose,[286] which is of central importance. As Ms. Stamper's report explained, although AGDC did describe that the AK LNG Project was "water dependent" and thus sited the Liquefaction plant to allow for waterborne vessels,[287] it did not describe use of

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[282] Stamper Report at 20-21.
[283] Stamper Report at 19-20.
[284] *Helping Hand*, 848 F.3d at 1195; *see also Sierra Club*, 499 F.3d at 654 ("EPA's position is that [BACT] does not include redesigning the plant proposed by the permit applicant" (citing NSR Workshop Manual at B.13).
285 Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 30. Stamper Report at 22.

[286] Furthermore, while state permitting agencies are "not necessarily required to follow the analytical framework used by EPA [and the EAB] to assess whether an option may be- excluded from a BACT analysis on 'redefining the-source' grounds,'" the state agency, if "intend[ing] to employ a different approach," must "articulate its intent to do so and provide a statutory foundation for any alternative approach." *Cash Creek I*, at 9.
[287] Stamper Report at 22.

natural-gas burning turbines as one of its business purposes. Additionally, as Ms. Stamper's report explains, ADEC must along consider a mix of electric and natural gas fired turbines.[288] AGDC made other faulty assumptions for using electricity from the grid in lieu of the power turbines.[289]

ADEC, contrary to the BACT regulations requiring consideration of control options, erred in totally excluding the evaluation of using electric compressor engines or electricity from the grid to replace its proposed power turbines in the GHG BACT analysis of its Technical Analysis Review.[290] For the reasons detailed in Ms. Stamper's analysis, ADEC should consider electric compressors (if not for all engines (i.e., if grid capacity is limited), then for at least some of the compressor turbines) in lieu of natural gas-fired compressors.[291] Moreover, to the extent ADEC decides to rely on mere assertions made by AGDC, it must support them with verified, factual information.

3. ADEC's Consideration of Aeroderivative Turbines Fails to Follow the Regulatory Requirements

As discussed in detail in Ms. Stamper's Report, there are several emission reduction benefits of use of aeroderivative turbines compared to heavy duty frame turbines for the compressor turbines at the Liquefaction plant.[292] In fact, aeroderivative turbines are being used in other LNG projects including Sabine Pass, Trunkline Project, and Corpus Christi.[293] While AGDC calculated the incremental cost of using aeroderivative turbines in lieu of heavy frame industrial compressor turbines to be $32/ton of GHG removed.[294] ADEC eliminated aeroderivative turbines from consideration in the BACT analysis for both the compressor turbines and power turbines because "it would fundamentally redefine the project…."[295] As explained in Ms. Stamper's report, there is no basis for ADEC to claim that use of aeroderivative turbines instead of industrial frame turbines would redefine the project. Aeroderivative turbines are combustion turbines that are more fuel efficient than heavy frame industrial turbines, and they can be operated in both simple cycle mode (such as to drive compressors) and combined cycle mode.[296] Further, AGDC has not identified the make and model of turbines that it intends to install. Thus, ADEC is without basis to claim that consideration of a more fuel-efficient

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[288] *In re N. Mich. Univ. Ripley Heating Plant*, 14 E.A.D. 283, 301–02 (E.A.B. 2009)("IMU"); *see also Cash Creek I.*
[289] Stamper Report at 24.
[290] It appears one reason ADEC failed to consider options is that it limited its consideration of control options to unspecified methodology it used to search EPA's RBLC. ADEC has failed to provide details on how it conducted its searching: although NPCA asked for this information, ADEC refused to provide it. Furthermore, the BACT analysis is clearly not limited to a mere review of the RBLC. While that is one place to look, ADEC clearly missed other options by not conducting a broader search.
[291] Stamper Report at 22-24.ADEC must not automatically dismiss the use of electric turbines as an impermissible redesign, particularly as "the CAA promotes "clean fuels" with particular vigor. *See* CAA § 169(3), 42 U.S.C. § 7479(3)." *IMU* at 302. Clean fuels may not be "read out" of the Act merely because their use requires "some adjustment" to the proposed technology. *Sierra Club*, 499 F.3d at 656.
[292] Stamper Report at 24, 27-28.
[293] *Id.* at 24.
[294] As discussed in PreTAR, Appendix B at 18 including Table 3-11.
[295] PreTAR, Appendix B at 17 and 34.
[296] Stamper Report at 24-5 and 27.

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turbine in an analysis of BACT for greenhouse gas emissions would be a redefinition of the project.

Furthermore, AGDC's incremental cost analysis of aeroderivative compressor turbines, the use of aeroderivative gas turbines appears to be very cost effective at $32/ton. However, AGDC did not provide the assumptions that went into this Yet – as Ms. Stamper explains AGDC claimed aeroderivative turbines would only be cost effective if turbine fuel costs were $7.50 per million British Thermal Units (MMBtu) or greater.[297] Although AGDC did not provide the background data that went into this incremental cost analysis or explain its finding, it appears that AGDC's criteria of consideration of aeroderivative turbines to meet BACT for GHG was whether the costs of the aeroderivative turbines would be close to the same as the industrial turbines. Ms. Stamper's report explains that AGDC failed to answer the fundamental question posed by the cost effective analysis; which is whether it is cost effective to use aeroderivative turbines, which would emit less GHG emissions for the same amount of power generation. Indeed, AGDC's own analysis admits that "other comparable LNG projects have incorporated [aeroderivative turbines] into their design" including Sabine Pass, Trunkline Project, and Corpus Christi,[298] which shows that other similar sources have used these turbines to reduce GHG emissions.

Ms. Stamper's report further explains the challenges the public faced in reviewing this proposed action. Although AGDC conducted what it characterized as a "cost effectiveness analysis," the information ADEC made available at the start of the public comment period failed to include any of the details regarding AGDC's cost effectiveness analysis. AGDC's increment cost spreadsheet was made available to the public at the request of National Parks and Conservation Association, after ADEC negotiated with AGDC to have them withdraw its wrongfully asserted Confidential Business Information (CBI) claims.[299] Based on Ms. Stamper's review and analysis, AGDC's analysis contained numerous errors (e.g., taking into account capital costs to replace the planned 6 compressor turbines with 12 smaller capacity aeroderivative turbines when aeroderivative turbines of the same size as the planned compressor turbines are available, more than doubling the interest rate in amortizing capital costs, and overstating maintenance costs).[300] Moreover, AGDC assumed a higher heat rate for the aeroderivative turbines than is justified. which had the effect of underestimating the amount of GHG reductions from use of aeroderivative turbines and overstating the amount of fuel necessary for the aeroderivative turbines.[301]

As seen in Ms. Stamper's report, by correcting these assumptions, she found the incremental cost effectiveness of use of aeroderivative turbines reduces to $29/ton.[302] For this analysis, Ms. Stamper assumed the cost for natural gas was $2.57/MMBtu based on the Henry Hub Natural Gas Spot Price for January to December of 2019 as the cost for natural gas.[303] Thus, as she explains, use of aeroderivative turbines could be a cost effective GHG control, and

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[297] *Id.* at 25.
[298] Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 29.
[299] See spreadsheet entitled "23_Trade Secret_cost effectiveness_Compression Turbines" at row 24 of tab entitled "GHG-Incremental" that was included in the "2018.05.01 Original Submittal" provided to NPCA by ADEC in November of 2020.
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[300] Stamper Report at 25-27.
[301] Stamper Report at 26-27.
[302] *Id.* at 26.
[303] *Id.*

use of such turbines would avoid approximately 410,000 tons per year of GHG emissions simply by using more energy efficient turbines for the compressor turbines.[304] In addition to the decreased GHG emissions, turbines that use less natural gas will also emit lower levels of all other air pollutants on an hourly and annual basis.[305]

Furthermore, AGDC's BACT analysis did not discuss use of aeroderivative turbines at all for the power turbines, but it should have. Along with reduced GHG emissions, there are several other benefits that could be realized with the use of aeroderivative gas turbines, such as improved ability to reduce NOx with SCR, shorter startups, less frequent and lower downtime for maintenance which will reduce flaring emissions, and lower emissions of all air pollutants due to burning less fuel for the same level of power produced.[306] Thus, this GHG control technique of using aeroderivative turbines must be given more weight in ADEC's GHG BACT analysis as it appears to be a very cost effective method of reducing GHG emissions with several other air quality benefits.

4. ADEC Has Not Justified that the GHG Limit it Proposes is BACT

Contrary to the requirements in Alaska's SIP, ADEC fails to evaluate and document GHG BACT for the compressor turbine and the power turbines. For example, ADEC fails to provide a technical basis for its proposed GHG BACT limit for the compressor turbines and power turbines, it merely suggests the limit is based on good combustion practices and burning clean fuels.[307] Furthermore, in setting this limit, ADEC cannot rely on AGDC's information for the CO2 emissions rate per megawatt-hour for its compressor turbines, because AGDC did not provide nor does the permit specify the turbine make or model.[308] As Ms. Stamper identifies in her report, "A review of the draft permit shows that ADEC has imposed the same 117.1 lb/MMBtu GHG BACT limit for every emission unit at the proposed Liquefaction plant – that is, the compressor turbines, the combined cycle emission units, and the flares."[309] These are not case-specific BACT determinations, rather ADEC's proposed limits are "simply the EPA GHG emission factor for natural gas combustion at any type of combustion source."[310] Contrary to the requirements, ADEC's limit does not:

- Reflect the maximum degree of GHG emission reduction achievable for the source considering costs of control and other impacts; and
- Encourage improvements in efficiency or even good combustion practices.

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[304] *Id.* at 28.
[305] *Id.*
[306] *Id.* at 27-28.
[307] Stamper Report at 28-29. Additionally, as Ms. Stamper explains, AGDC's submittal similarly lacks the required BACT evaluation as AGDC did not identify any claimed heat rate for those turbines and simply proposed using a combined cycle turbine, low carbon fuel, and energy efficiency as BACT for GHG emissions. Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 44.
[308] *Id.*
[309] Stamper Report at 29.
[310] *Id. See* EPA GHG Emission Factors, available at https://www.epa.gov/sites/production/files/2020-04/documents/ghg-emission-factors-hub.pdf. The emission factors for CO_2, methane (CH_4) and nitrous oxide (N_2O) convert to 117.1 lb/MMBtu (after applying the global warming potential factors in 40 C.F.R. Part 98, Table A-1.

Moreover, as explained in Ms. Stamper's report, ADEC's GHG BACT determination for the power turbine was based on "maintaining good combustion practices and burning clean fuels at all times"[311] and nothing in the permit requires that the power turbines be operated in combined cycle mode nor does the permit limit the time such units can operate in the less efficient simple cycle mode.[312] This is an issue because operating in a combined cycle mode is a GHG BACT control, and at the very minimum, ADEC's GHG BACT limit for the power turbines must be based on the combined cycle operation of the units.[313]

Furthermore, ADEC's proposal is inconsistent with EPA's GHG permitting guidance, which, states that: GHG BACT limits should at the minimum encourage energy efficiency by being output-based limits (as in lb/MW-hr or lb/horsepower-hour); and other requirements may also be imposed to ensure energy efficiency, such as an environmental management system focused on energy efficiency.[314] The proposed BACT limits do not provide for energy efficiency and require any level of GHG control other than burning natural gas.

In sum, as highlighted in these comments and discussed in more detail in Ms. Stamper's Report, there are several options that ADEC should considered in adopting a BACT emission limit for GHG, including carbon capture and sequestration, use of electric compressors, use of aeroderivative turbines, and operating in combined cycle mode. Between its lack of a full evaluation of GHG control options and the lack of documentation in the record to support its proposed emission limit, the GHG BACT determinations for the compressor turbine and the power turbines are wholly inadequate and must be redone.

D. ADEC Must Not Exempt Startup and Shutdown from BACT Emission Limits

BACT is an "emission limitation," and an "emission limitation" is defined as a requirement that limits the rate of emissions "on a continuous basis."[315] As detailed in Ms. Stamper's report,[316] ADEC's exemptions for the compressor and power turbines from complying with BACT limits during startup and shutdown are inconsistent with the definition of BACT and must be removed.

Additionally, Ms. Stamper's report documents numerous concerns about the enforceability of the proposed permit regarding startup and shutdown situations:

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[311] ADEC's Preliminary September 11, 2020 TAR, Appendix B at 36.

[312] Draft Permit at 1, Table 1. Notably, the Draft Permit states that the "information in Table 1 is for identification purposes only" and that "[t]he specific [emission unit (EU)] descriptions do not restrict the Permittee from replacing an EU identified in Table 1." *Id.*

[313] Stamper Report at 29.

[314] *Id.*, citing EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, EPA-457/B-11-001, March 2011, at 46.

[315] 18 AAC 50.990(30)(definition of "emission limitation" has the meaning given in AS 46.14.990. AS 46.14.990(10) defines "emission limitation" and "emission standard" as in 40 C.F.R. § 51.100(z)("*Emission limitation* and *emission standard* mean a requirement established by a State, local government, or the Administrator which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirements which limit the level of opacity, prescribe equipment, set fuel specifications, or prescribe operation or maintenance procedures for a source to assure continuous emission reduction.")

[316] Stamper Report at 30-31.

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- ADEC's proposed work practice standards for the power turbines are vague and provide significant flexibility to AGDC without providing assurance that emissions will be minimized during these periods;[317]

- It does not require any recordkeeping or reporting on the frequency, magnitude, and duration of exceedances of BACT emission limits during startup, shutdown, or malfunction:

- It does not require any documentation that manufacturer's specifications and good combustion practices were followed during such periods.[318]

Further, as demonstrated in other states – and presented in Ms. Stamper's report – it is feasible to impose alternative emission limits that apply during periods of startup and shutdown.[319] If ADEC justifies the need for alternative BACT limits during startup and shutdown at the compressor turbines and the power turbines, such alternative limits should apply only to BACT limits for NOx, CO and VOC emissions. Table 4 of Ms. Stamper's report provides examples from other permitting authorities.[320] For SO_2, PM_{10} and $PM_{2.5}$ emissions, no exemption from BACT requirements should be authorized at all. BACT for PM (PM_{10} and $PM_{2.5}$) and SO_2 at natural gas-fired combined cycle power plants is based on burning pipeline quality natural gas with low sulfur content, and the effectiveness of that pollution control does not vary during periods of startup and shutdown.[321]

Since BACT is to be met during all periods of operation, ADEC must revise the draft permit terms and conditions for the compressor turbines and the power turbines to ensure that the maximum degree of emissions reduction is required on a continuous basis.

E. ADEC's BACT for the Diesel-Fired Engines (EU 11 and 12) is Unlawful

The Liquefaction plant will have two diesel-fired engines- a 575 horsepower diesel fire pump (EU 11) and a 300 horsepower diesel-fired auxiliary air compressor engines (EG 12). The Draft Permit limits operations of these engines to 500 hours per year each.[322] These engines are of a source category regulated under the EPA's New Source Performance Standards (NSPS) at 40 C.F.R. Part 60, Subpart IIII (Standards of Performance for Stationary Internal Combustion Engines). Therefore, as discussed in detail earlier in our comments, BACT can be no less stringent than the applicable NSPS standards. As presented in detail in Ms. Stamper's Report, ADEC has proposed BACT limits for these engines that are less stringent than the NSPS BACT floor.[323]

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[317] ADEC simply requires that AGDC operate the turbines "according to manufacturer's specifications and good combustion practices." Draft Permit at 13 and 17.
[318] Stamper Report at 30.
[319] *Id.* at 14 (Table 4) and 30.
[320] *Id.* at 14 and 30-31.
[321] *Id.* at 30-31.
[322] Draft Permit at 12.
[323] Stamper Report at 31-33.

Given that BACT is supposed to be based on the maximum degree of emission reduction achievable and the fact that this is a new Liquefaction plant, ADEC should require that both diesel engines meet Tier 4 emission standards as BACT limits.[324] Tier 4 engines are readily available and, given that Tier 4 engines achieve the lowest emission rates of NOx, PM and CO, such engines should be considered BACT for the firewater pump (EU 12) as well as for the auxiliary air compressor (EU 11).[325]

F. ADEC's BACT for the Flares is Unlawful

The Liquefaction plant will have 7 flares: a dry ground flare and wet ground flare (maximum capacities of 55,000 million standard cubic feet per hour (Mscf/hr) and of 13,000 Mscf/hr) for each of the three LNG lines (EU's 14-19), and an elevated low pressure flare with maximum relief capacity of 990 Mscf/hr (EU 20).[326]

While ADEC conducted a BACT analysis for the various pollutants to be emitted by the flares, the emission limits it has proposed are, with the exception of SO_2, simply reflective of EPA emission factors for flares.[327] While ADEC's draft permit will limit the number of hours each flare can operate to not more than 500 hours per consecutive 12 months, the limit applies only to flaring during startup, shutdown, and maintenance events and does not include upsets or emergency flaring, which can be a significant cause of prolonged flaring. [328] The Draft Permit also imposes a GHG emission limit of 117.1 lb/MMBtu[329] which, as stated above, is simply the same as the EPA GHG emission factor for GHG emissions from natural gas combustion (i.e., it does not require any reduction in GHG emissions). Further, although ADEC has proposed emission limits in terms of lb/MMBtu for NOx, CO, PM, VOCs, and GHG, there are no requirements to ensure that these emission limits are met, other than training of flare operators and meeting the work practice standards of 40 C.F.R. §§ 60.18(c) through (f).[330] Ms. Stamper's Report continues additional important information on flare operations.[331]

1. ADEC Failed to Evaluate Capture and Use of the Excess Natural Gas Stream in Lieu of Flaring the Excess Natural Gas Stream

ADEC improperly ignored other techniques in lieu of flaring, including the top BACT option: eliminate flaring by capturing the excess gas for use, rather than to flare the excess gas. Ms. Stamper's report presents several options to capture and use of the excess gas.[332] ADEC should evaluate this option as a BACT control for all pollutants emitted by flaring.

2. ADEC Failed to Evaluate the Control Option of Use of a Thermal Incinerator in Lieu of Flares

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[324] Stamper Report at 33.
[325] *Id.*
[326] Draft Permit at 1 (Table 1).
[327] ADEC's Preliminary September 11, 2020 TAR, Appendix B at 64, 66, 67, 71, and 73. Stamper Report at 34.
[328] Draft Permit at 23 (Condition 17).
[329] *Id.*
[330] *Id.* at 24.
[331] Stamper Report at 33-35.
[332] Stamper Report at 35.

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Another control option that ADEC should evaluate is requiring excess natural gas to be combusted in a thermal incinerator, rather than through flaring, in which the combustion of the natural gas could be controlled to a much greater extent than in an open flame of an elevated flare. As explained in Ms. Stamper's report, use of thermal incinerators instead of flaring could provide for greater control of VOCs through the ability to control and optimize the combustion of the gas, and low NOx burners are available which could decrease NOx emissions as compared to flaring of the natural gas.[333]

For these and other reasons discussed in Ms. Stamper's Report, ADEC erred in not evaluating the use of a thermal incinerator as a BACT option in lieu of flaring.

3. ADEC's Proposed Permit Requirements for Minimization of Flaring Are Inadequate to Reflect BACT

As Ms. Stamper explains, minimization of flaring is another important BACT option to fully evaluate. ADEC stated that it based its BACT determination on establishing a flare minimization plan, and the permit requires that AGDC develop and keep on-site a flare minimization plan.[334] However, the provisions of the Draft Permit regarding the flare minimization plan do not reflect enforceable requirements, because the Draft Permit simply leaves it up to the company to develop a flare minimization plan without requiring that plan to be submitted to and reviewed by ADEC and/or become part of the permit. In addition, as the LNG plant ages, the approaches to minimizing flaring may change over time. Thorough recordkeeping and reporting of flaring incidents from all causes (startup, shutdown, maintenance, as well as upsets) is imperative for ensuring that flaring is minimized. Recordkeeping and reporting allows for lessons to be learned from flaring events and for appropriate flaring minimizing plans to be put into place from excess flaring events.[335] Ms. Stamper's report lists the factors EPA has listed to prevent excess flaring at refineries, and this same approach can be used to identify methods and techniques to reduce flaring at LNG facilities, along with other EPA recommendations to reduce the amount of flaring due to upsets.[336]

Finally, Ms. Stamper's Report discusses in detail numerous additional provisions that ADEC must include to ensure the flares are maintained and operated properly and that use of flares is minimized. Importantly, a limit on total hours of flaring due to all causes including upsets would provide significant incentive for AGDC to truly minimize flaring of excess gas.

ADEC must analyze all of these BACT options for flaring , including capture and use of excess gas to eliminate or greatly minimize flaring and use of a thermal incinerator in lieu of flaring for more complete combustion and better control of VOCs and NOx. If ADEC determines flare minimization is the top BACT control option, it must include additional requirements in the permit to ensure that flaring is truly minimized.

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[333] *Id.* at 35-36.
[334] Draft Permit at 24.

[335] Stamper Report at 37.
[336] *Id.*

VI. The Draft Permit Unlawfully Relies on Deficient and Inaccurate Air Quality Modeling

An air quality analysis provides predictions of pollutant concentrations in ambient air by modeling the impacts of new emissions from a proposed source. Congress' concern about modeling science led it to require EPA to establish uniform modeling techniques for use in PSD permitting. EPA is expected to develop and utilize the most accurate and feasible modeling techniques available, and to review and update those models periodically as modeling science develops.[337] EPA did develop modeling guidelines, 40 C.F.R. § 52.21(1), and they were subsequently upheld on judicial review.[338] PSD permit applicants use modeling to demonstrate compliance with the requirements for obtaining a permit.[339] The main purpose of the air quality impacts analysis is to demonstrate that the new emissions emitted from a proposed major stationary source, in conjunction with other applicable emissions from existing sources, will not cause or contribute to a violation of any applicable NAAQS or PSD increment.[340] The NAAQS are maximum concentration 'ceilings' measured in terms of the total concentration of a pollutant in the atmosphere for certain pollutants that apply nationwide. The standards are set at levels that the Administrator of EPA has determined are necessary to protect the public health and welfare. PSD increments are maximum allowable increases in pollutant concentration over baseline concentrations. The permit applicant's the analysis must calculate whether the proposed emissions will be within the applicable PSD increment The PSD increment concept was designed to accommodate economic growth and increased pollution associated with such growth while placing limits on new pollution. Significant deterioration is prevented if the amount of new pollution from the proposed source, in conjunction with pollution from certain existing sources, is less than the amount permitted by the PSD increment.[341] Permit applicants must use EPA-approved models.[342] Written approval from EPA's Administrator is required for model substitutions and modification, as well as public notice and opportunity for comment.[343] If, after taking into account emissions from a proposed source and emissions from certain existing sources, the modeled ambient air concentration of a pollutant is below the NAAQS, and the

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[337] *See* 42 U.S.C. §§ 7475(e)(3)(D) and 7620.

[338] *Alabama Power.*

[339] *See, e.g,. Hadson Power.*

[340] 18 AAC 50.040(h)(9), incorporating by reference 40 C.F.R. § 52.21(k) (Source Impact Analysis)("The owner or operator of the proposed source or modification shall demonstrate that allowable emission increases from the proposed source or modification, in conjunction with all other applicable emissions increases or reductions (including secondary emissions), would not cause or contribute to air pollution in violation of:
(1) Any national ambient air quality standard in any air quality control region; or
(2) Any applicable maximum allowable increase over the baseline concentration in any area.")

[341] *See* NSR Workshop Manual at C.3.

[342] 18 AAC 50.040(h)(10), incorporating by reference 40 C.F.R. § 52.21(l)(1) ("All estimates of ambient concentrations required under this paragraph shall be based on applicable air quality models, data bases, and other requirements specified in appendix W of part 51 of this chapter (Guideline on Air Quality Models).")

[343] 18 AAC 50.040(h)(10), incorporating by reference 40 C.F.R. § 52.21(l)(2) ("Where an air quality model specified in appendix W of part 51 of this chapter (Guideline on Air Quality Models) is inappropriate, the model may be modified or another model substituted. Such a modification or substitution of a model may be made on a case-by-case basis or, where appropriate, on a generic basis for a specific state program. Written approval of the Administrator must be obtained for any modification or substitution. In addition, use of a modified or substituted model must be subject to notice and opportunity for public comment under procedures developed in accordance with paragraph (q) of this section."). *See also In re AES Puerto Rico L.P.*, 8 E.A.D. 324, 337 (EAB 1999) .

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increase in concentration for that pollutant is less than the applicable PSD increment, the permit applicant has successfully demonstrated compliance.[344]

The models are listed in the "Guideline on Air Quality Models" 40 C.F.R. part 51, appendix W.[345] ADEC adopts EPA's Guideline on Air Quality Models by reference, which was most recently approved by EPA on August 29, 2019 to include the following: 18 AAC 50.040(f) ("The provisions of 40 C.F.R. Part 51, Appendix W (Guideline on Air Quality Models), revised as of July 1, 2017, are adopted by reference.") EPA's 2019 approval also included 18 AAC 50.215 Ambient Air Quality Analysis Methods.

As discussed in Mr. Gebhart's Report, ADEC's "lack of scientific certitude about modeling techniques"[346] relied on and developed for the proposed PSD permit, demonstrates the need for the agency to develop new accurate information that meets the regulatory requirements and renotice the proposed permit to provide for public comment.

A. ADEC Inappropriately Relies on the Modeling Analysis Prepared for NEPA Compliance

As explained in Mr. Gebhart's Report, "the PSD permit modeling for the most part relied upon air quality modeling completed by the applicant for the EIS," which "was seriously flawed and these flaws were therefore carried forward into the PSD permit modeling."[347] For example the:[348]

- EIS indicated that the technical information about the Project used for the air quality modeling assessment was outdated and/or incorrect;
- Construction-related emissions were inconsistent with the applicant's current project schedule and as such were outdated;
- CALPUFF modeling addressing Class I area impacts was incomplete because cumulative impacts were not properly addressed; and
- Maritime emissions were not calculated based on the maximum number of vessels serving the Liquefaction plant.

ADEC's PreTAR explained that:

> AGDC conducted various air quality demonstrations under the National Environmental Policy Act (NEPA) prior to submitting their permit application for the Liquefaction plant. They therefore relied on these previous demonstrations, to the extent possible, for the ambient analyses required under PSD. This type of coordinated approach is encouraged by

[344] NSR Workshop Manual at C.51. *See also In re Knauf I* at 149.
[345] *See* 40 C.F.R. § 52.21(l)(1)(" (1) All estimates of ambient concentrations required under this paragraph shall be based on applicable air quality models, data bases, and other requirements specified in appendix W of part 51 of this chapter (Guideline on Air Quality Models).") ("Guideline on Air Quality Model")
[346] *Alabama Power* at 388.
[347] Gebhart Report at 1.
[348] *Id.* at 2. Additional issues related to ADEC's reliance on the EIS air quality impact modeling are presented in these comments.

> EPA under 40 CFR 52.21(s). The Department has not adopted this citation by reference (since it has no control over the federal actions conducted under NEPA), but the Department nevertheless agrees that the analyses should be consistent where possible.[349]

As ADEC notes, 40 C.F.R. § 52.21(s) does not apply to the State. Furthermore, that particular regulation clearly states that while coordination between the Clean Air Act and NEPA is aspirational, it shall only be done to the "extent feasible *and reasonable*."[350]

Therefore, ADEC's proposed PSD permit analysis is also incomplete, inaccurate, and furthermore, does not provide for a complete understanding and analysis of air quality impacts as is required under federal and State of Alaska PSD permit regulations.[351] "ADEC's reliance on the EIS modeling, which was completed to fulfill a separate legal requirement, was inappropriate and in turn led to substantial and significant errors in the assessment of the real-world air quality impacts."[352] As discussed throughout these comments, it was unreasonable for ADEC to rely on information compiled in the NEPA context where the information fails to meet Clean Air Act requirements.

B. ADEC Failed to Consider the Range of Operations in the Modeling Scenarios

EPA's Guideline on Air Quality Models requires that

> For point sources, there are many source characteristics and operating conditions that may be needed to appropriately model the facility. For example, the plant layout (e.g., location of stacks and buildings), stack parameters (e.g., height and diameter), boiler size and type, potential operating conditions, and pollution control equipment parameters. Such details are required inputs to air quality models and are needed to determine maximum potential impacts.[353]
>
> For stationary source applications, changes in operating conditions that affect the physical emission parameters (e.g., release height, initial plume volume, and exit velocity) shall be considered to ensure that maximum potential impacts are appropriately determined in the assessment. For example, the load or operating condition for point sources that causes maximum ground-level concentrations shall be established. As a minimum, the source should be modeled using the design capacity (100 percent load). If a source operates at greater than design capacity for periods that could result in violations of the NAAQS or PSD increments, this load should be modeled. Where the source operates at substantially less than design capacity, and the changes in the stack parameters associated with the operating conditions could lead to higher ground level

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[349] PreTAR at 3.
[350] 40 C.F.R. § 52.21(s)("*Environmental impact statements.* Whenever any proposed source or modification is subject to action by a Federal Agency which might necessitate preparation of an environmental impact statement pursuant to the National Environmental Policy Act (42 U.S.C. 4321), review by the Administrator conducted pursuant to this section shall be coordinated with the broad environmental reviews under that Act and under section 309 of the Clean Air Act to the maximum extent feasible *and reasonable*.") (emphasis added)
[351] Gebhart Report at 1.
[352] *Id.* at 3.
[353] Guideline on Air Quality Model, ¶ 8.2.1 (b)

> concentrations, loads such as 50 percent and 75 percent of capacity should also be modeled. Malfunctions which may result in excess emissions are not considered to be a normal operating condition. They generally should not be considered in determining allowable emissions. However, if the excess emissions are the result of poor maintenance, careless operation, or other preventable conditions, it may be necessary to consider them in determining source impact. A range of operating conditions should be considered in screening analyses. The load causing the highest concentration, in addition to the design load, should be included in refined modeling.[354]

In modeling emission scenarios, it was unreasonable for ADEC not to consider different flaring operations. The dispersion modeling for the Liquefaction plant *only* addressed "normal operations," which was represented as full build-out of the liquefaction processing equipment at the maximum production rate.[355] However, Resource Report No. 9 Appendix D states that "considerable flaring over six (6) months" will occur during Liquefaction plant commissioning and start-up,[356] which was not addressed in the PSD permit modeling evaluation. Mr. Gebhart's Report explains that because flaring will have different air dispersion characteristics and would produce air quality impacts that might vary significantly from those modeled under "normal operations," one cannot rely solely on emissions comparisons when deciding if and when to model possible flaring scenarios.[357] Therefore, "[a]ppropriate flaring scenarios need to be independently considered; otherwise, the Liquefaction plant air dispersion modeling analysis as presented by the ADEC TAR is incomplete."[358]

Furthermore, "[u]nder the EPA Guideline on Air Quality Models (40 CFR 51, Appendix W), modeling of combustion sources at partial load is recommended because the plume rise will be less during partial load conditions, which can lead to elevated ground-level pollutant impacts even when emissions are less.[359] "Also, for the Liquefaction plant combustion turbines, only 100% load was considered in the air quality modeling impact analysis," and "[i]t was not realistic for ADEC to assume that the Liquefaction plant combustion sources would only operate at or near full capacity."[360] Instead, "[t]he air quality modeling needed to address the possibility of operating the combustion turbines and other combustion sources at less than 100% load. In the absence of such modeling, the PSD permit should have imposed appropriate operational restrictions to prohibit operating the turbines and other combustion sources at less than 100% load."[361]

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[354] Guideline on Air Quality Model, ¶ 8.2.2 (d)
[355] *Id.* at 3.
[356] Alaska LNG Project, "RESOURCE REPORT NO. 9 APPENDIX D – LIQUEFACTION FACILITY AIR QUALITY MODELING REPORT," at 9 (April 14, 2017), available at http://alaska-lng.com/wp-content/uploads/2017/04/Alaska-LNG-RR9-AppxD_041417_Public.pdf
[357] Gebhart Report at 2.
[358] *Id.*
[359] Guideline on Air Quality Model, ¶ 8.2.2 (d)
[360] Gebhart Report at 3.
[361] 18 AAC 50.040(h)(9), incorporating by reference 40 C.F.R. § 52.21(k), *see also* NSR Workshop Manual at C.24-25.

C. ADEC Ignores Onsite Meteorological Data, Fails to Demonstrate Data Used is Representative and Processes Data Inconsistently with Regulatory Requirements

In order to perform an air quality analysis, certain data must be obtained, including information on existing ambient air quality, emission rates from the proposed source, and meteorological data to predict how emissions will behave once they are emitted from the proposed source. Ambient background concentrations are essential in constructing the design concentration, or total air quality concentration, as part of a cumulative impact analysis for NAAQS and PSD increments.[362] Background air quality should not include the ambient impacts of the project source under consideration. Instead:[363]

- The monitoring network used for developing background concentrations is expected to conform to the same quality assurance and other requirements as those networks established for PSD purposes. Accordingly, the air quality monitoring data should be of sufficient completeness and follow appropriate data validation procedures. These data should be adequately representative of the area to inform calculation of the design concentration for comparison to the applicable NAAQS (section 9.2.2).[364]

- The EPA recommends use of the most recent quality assured air quality monitoring data collected in the vicinity of the source to determine the background concentration for the averaging times of concern. In most cases, the EPA recommends using data from the monitor closest to and upwind of the project area. If several monitors are available, preference should be given to the monitor with characteristics that are most similar to the project area. If there are no monitors located in the vicinity of the new or modifying source, a "regional site" may be used to determine background concentrations. A regional site is one that is located away from the area of interest but is impacted by similar or adequately representative sources.[365]

The liquefaction modeling analysis relied on five years of meteorological data from Kenai Airport (2008-12), yet it appears that on-site meteorological monitoring data was also collected at or near the Liquefaction plant.[366] EPA's Modeling Guideline, which is in Alaska's SIP "indicates a preference for on-site data when such data are available."[367] Therefore, "[t]he applicant should have used the on-site meteorological monitoring data for the air quality

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[362] Guideline on Air Quality Model, 9.2.3. The PSD requirements for the ambient air quality data are in 40 C.F.R. § 52.21(m)(1)(iv), which similarly require that the data is representative. 18 AAC 50.040(h)(11), incorporating by reference 40 C.F.R. § 52.21(m)(1)(iv).
[363] *Id.*, at 8.3.1(a).
[364] *Id.*, at 8.3.1(b).
[365] *Id.*, at 8.3.2(b).
[366] ADEC Draft Technical Analysis Report, Section 5.3, *See also* Resource Report #9.
[367] Guideline on Air Quality Model, ¶ 8.4.4.1 ("Site-specific measured data are therefore preferred as model input provided that appropriate instrumentation and quality assurance procedures are followed, and that data collected are adequately representative").

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modeling calculations or explained why the Kenai Airport data were more appropriate for the Liquefaction plant air quality analysis."[368]

In any case, any meteorological data used as input to air quality models supporting a PSD permit application need to be "representative" of the transport and dispersion conditions in the project area. Specifically, Appendix W carries the following language regarding the need for representative meteorological data:

> The meteorological data used as input to a dispersion model should be selected on the basis of spatial and climatological (temporal) representativeness as well as the ability of individual parameters to characterize the transport and dispersion conditions in the area of concern.[369]

However, the ADEC TAR and other information in the record are silent as to whether the Kenai Airport data are "representative." Until the Kenai Airport data are evaluated and shown to meet the "representative data" criterion in Appendix W and the regulation, they cannot be used to support a PSD permit application.

Lastly, the TAR notes that the applicant's modeling of air quality impacts "randomized" the wind directions when processing the Kenai Airport meteorological data. This is contrary to USEPA guidelines when meteorological data are processed with the AERMINUTE data processor, which occurred in this case. The applicable EPA guidelines on this issue were well established and date to 2013,[370] long before the applicant filed the modeling protocol and completed the Liquefaction plant air modeling for the PSD permit. ADEC should have invalidated the applicant's modeling and instead required that the meteorological data processing conform with EPA and ADEC guidelines (please refer to additional comments later in Mr. Gebhart's Report that address ADEC's so-called sensitivity analyses, which is how ADEC tried to address this issue and other inconsistencies between the applicant's modeling and applicable modeling guidelines).

D. ADEC Relies on Baseline Air Quality Data that is Not Representative of Baseline Conditions

As Mr. Gebhart's Report explains, "[a]ll PSD applicants need to collect ambient air quality measurements documenting baseline conditions representative of the current air quality at

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[368] Gebhart Report at 3. Moreover, an applicant cannot substitute ambient data unless it is deemed "sufficiently representative of air quality in the targeted area — in terms of the sufficiency of the monitoring locales selected and the quality and currentness of the monitoring data — to legitimately be substituted for site-specific data." *NMU* at 325, *citing* NSR Workshop Manual at C.18-19; *Ambient Monitoring Guidelines* § 2.4, at 6-9; *see also, e.g., Knauf I at* 145-48; *In re Haw. Elec. Light Co.*, 8 E.A.D. 66, 97-105 (EAB 1998); *In re Hibbing Taconite Co.*, 2 E.A.D. 838, 850-51 (EAB 1989).

[369] Guideline on Air Quality Model, ¶ 8.4.1(b).

[370] U.S. Environmental Protection Agency, 2013. Use of ASOS meteorological data in AERMOD dispersion modeling. Memorandum dated March 8, 2013, Office of Air Quality Planning and Standards, Research Triangle Park, NC. https://www3.epa.gov/ttn/scram/guidance/clarification/20130308_Met_Data_Clarification.pdf. (cited at n95 in the Guideline on Air Quality Model)

the project site, or otherwise demonstrate that it meets the applicable monitoring exemptions under the applicable PSD regulations. In part, the applicant met this requirement by collecting on-site measurements for nitrogen oxides (NOx), sulfur dioxide (SO_2), and carbon monoxide (CO), which operated from September 2018 through August 2019."[371]

"However, for the PM-10, PM-2.5, and ozone (O3) baseline monitoring, the applicant relied upon data collected during 2013-14 to support a previous PSD permit action by a nearby facility (Agrium). These data cannot be used to support a PSD permit action in 2020 as the 2013-14 data no longer accurately represent the current baseline air quality conditions around the Liquefaction plant site. Even at the time that the PSD permit application was filed by the applicant (May 1, 2018), these data were approaching five years old. The applicant has not complied with the PSD baseline monitoring requirements because the applicant has relied upon data which is out of date and no longer representative of baseline air quality conditions."[372]

E. ADEC's Methodology is Inconsistent with the Regulatory Requirements for NOx Emissions Modeling

The Liquefaction plant modeling applied the Ambient Ratio Method (ARM2) to address the atmospheric conversion of NOx emissions to nitrogen dioxide (NO_2), which is the regulated form for NOx under the National Ambient Air Quality Standards (NAAQS). ARM2 is the recommended Tier 2 modeling approach under the Guideline.[373] The Modeling Guideline recommends 0.5 for the lower limit in the ARM2 calculations. However, the Liquefaction plant NOx modeling used the Tier 2 Ambient Ratio Method (ARM2) lower limit as 0.2, which does not conform to the Modeling Guideline.[374, 375] While prior versions of Appendix W may have listed lower thresholds for this variable, the current version in ADEC's SIP is the 2017 Guideline, which EPA adopted nearly four years ago.[376] Therefore, the Liquefaction plant

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[371] Gebhart Report at 4. *See* 18 AAC 50.040(h)(11), incorporating by reference 40 C.F.R. § 52.21(m)(b)(iv)("In general, the continuous air quality monitoring data that is required shall have been gathered over a period of at least one year and shall represent at least the year preceding receipt of the application, except that, if the Administrator determines that a complete and adequate analysis can be accomplished with monitoring data gathered over a period shorter than one year (but not to be less than four months), the data that is required shall have been gathered over at least that shorter period.")

[372] Gebhart Report at 4.

[373] Guideline on Air Quality Model, ¶ 4.2.3.4.d).

[374] Gebhart Report at 4.

[375] Guideline on Air Quality Model 4.2.3.4 Models for Nitrogen Dioxide ("d. For Tier 2, multiply the Tier 1 result(s) by the Ambient Ratio Method 2 (ARM2), which provides estimates of representative equilibrium ratios of NO2/NOx value based ambient levels of NO2 and NOx derived from national data from the EPA's Air Quality System (AQS).55 The national default for ARM2 includes a minimum ambient NO2/NOx ratio of 0.5 and a maximum ambient ratio of 0.9. The reviewing agency may establish alternative minimum ambient NO2/NOx values based on the source's in-stack emissions ratios, with alternative minimum ambient ratios reflecting the source's in-stack NO2/NOx ratios. Preferably, alternative minimum ambient NO2/NOx ratios should be based on source-specific data which satisfies all quality assurance procedures that ensure data accuracy for both NO2 and NOx within the typical range of measured values. However, alternate information may be used to justify a source's anticipated NO2/NOx in-stack ratios, such as manufacturer test data, state or local agency guidance, peer-reviewed literature, and/or the EPA's NO2/NOx ratio database.")

[376] Gebhart Report at 4.

analysis must apply the most current data and information in the Model Guideline to the Liquefaction plant PSD permit modeling.

F. ADEC Underestimates Maritime Emissions and Fails to Include them in the Increment Analysis

Based on the air quality modeling description in Resource Report No. 9, Appendix D, maritime emissions were considered only when they occurred in the immediate vicinity of the LNG loading dock (within 500 meters).[377] As explained in Mr. Gebhart's Report, "[e]missions from the vessels impact air quality at considerable distances from the source and these impacts are not limited to just 500 meters. The 500 meter modeling limitation for maritime emissions was not appropriate nor was it scientifically defensible. The air quality modeling should have considered maritime emissions associated with the project beyond those that occur close to the loading dock." The 500 meter assumption is very limiting and results in an implicit assumption that emissions occurring beyond 500 meters have no impact on air quality concentrations. An arbitrary exclusion of real-world emissions from the modeling goes against the general concept that modeling should attempt to address uncertainties with conservative assumptions.

Furthermore, the AK LNG Project FEIS stated that the maritime emissions were not calculated based on the maximum number of vessels serving the Liquefaction plant,[378] and since the PSD permit modeling used the modeling data generated by the Draft EIS, which again was improper, this error also translated to the PSD permit modeling. Therefore, the results in the air quality impacts were underestimated.

Lastly, an impact analysis for maritime emissions transiting the Cook Inlet on the Class I Tuxedni National Wildlife Refuge (TUXE) has not been conducted. These maritime emissions would consume PSD increment and would have the potential to impact the nearby onshore Class I PSD areas. Any increase in emissions from maritime traffic will occur after the minor source baseline date consumes PSD increment. As such, PSD increment consuming emissions would be present not only from maritime traffic travelling to/from the Liquefaction plant, but also from some of the maritime traffic serving other facilities in Kenai and elsewhere in the Cook Inlet. By not properly considering the maritime emissions at the point where such emissions are in the proximity of TUXE, the air quality impacts to this Class I area have been underestimated.

G. Flaring Emission Must Represent Permitted Not "Average" Emission

The air quality modeling included emissions from emergency equipment such as flares, emergency engines, and other sources. However, in many cases, these sources were modeled at their annual average emissions rate, which substantially underestimated short-term emissions, which are allowed under the proposed permit, when these emergency sources actually operate.

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[377] Resource Report No. 9, Appendix D, at 32.
[378] Gebhart Report at 4.

The air quality modeling assessment needed to be based on realistic scenarios for operation of the emergency equipment that accounted for the actual short-term emissions of such equipment when these sources operate. If permitted, the Liquefaction plant will emit flare emissions over a specific period of time, such emissions are not emitted on an annual average. Therefore, the current modeling analysis underestimates the short-term emissions and associated impacts from this equipment.

The emissions modeling for the flaring scenarios are documented in Resource Report #9, Appendix D, Table 4-3. The table below extracts the data on the flaring emissions modeled by the applicant from the EIS documentation. Although this table comes from the EIS documentation, ADEC has asserted that it relied upon the EIS modeling for the purpose of quantifying air quality impacts for the Liquefaction plant PSD permit. Also listed in this table are the operating hours upon which the annual emissions total at the individual flares have been computed.

Figure 4. Flaring Emissions Modeled by the Permit Applicant

Model ID	Description	Op Hrs	NOx (g/sec)		SO_2 (g/sec)			PM-10/PM-2.5 (g/sec)	
			1-hr	Ann	1-hr	3& 24-hr	Ann	24-hr	Ann
DRYMAX 1&2	Dry Grnd Flare: Max Case	500	29.3	29.3	1.08	3.14	1.08	4.44	12.2
WETMAX 1&2	Wet Grnd Flare: Max Case	500	6.86	6.86	0.251	0.734	0.251	1.04	2.85
LPMAX	Low Press Flare: Max Case	144	0.148	0.148	5.67E-3	0.345	5.67E-3	3.55	5.83E-2

Based on the above table, flaring emissions for compliance with the applicable 1-hour NOx and SO_2 NAAQS were modeled at the annual emissions rate. This approach significantly underestimated the short-term emissions from max case flaring operations as this approach essentially smoothed out flaring emissions over the year instead of modeling the short-term spikes in flaring emissions that would actually occur. Also, flaring emissions would occur with sufficient frequency to affect the form of the standard for the 1-hour NOx and SO_2 NAAQS. For example, the max case flaring emissions may occur up to 500 hours per year for individual flares (based on the ADEC analysis). At 500 hours per year, flaring could occur on a minimum of 21 days per year (e.g., 500/24 = 20.8), and would likely occur on significantly more days since flaring would not be expected to occur continuously over 500 hours. This means that the frequency of flaring would affect ambient air concentrations on more than 1 percent of all days for the SO_2 NAAQS and more than 2 percent of all days for the NO_2 NAAQS. As such, the

maximum emissions and not the average emissions needed to be modeled for the 1-hour NAQQS compliance analysis.[379]

When modeling compliance with the 3-hour and 24-hour standards, the LPMAX emissions were modeled using a higher emission rate that appears to be indicative of the maximum short-term emissions rate at this flare. The same approach should have been used for modeling compliance with applicable 1-hour NAAQS.

At the dry/wet ground flares, the SO_2 emissions were modeled for the 3-hour and 24-hour average at a higher emissions rate, although it is unclear how the higher 3-hour/24-hour rate was derived. The data in the table show that the 3-hour/24-hour emissions were increased by about a factor of three above the annual emissions rate. However, extrapolating from 500 hours of annual operation would suggest that the maximum short-term emissions at the various ground flares should have increased by about a factor of about 17.5, e.g., 8760/500. The basis for the factor of three was not explained in the modeling documentation.

For PM-10 and PM-2.5 emissions, the table indicates that the ground flares were modeled at a lower emission rate for the 24-hour modeling compared to the annual emissions, which should never occur. The maximum 24-hour emissions should always be at or above the annual emissions rate. Again, extrapolating from 500 hours of operation would result in a factor of about 17.5 for the increase in the maximum short-term PM-10 and PM-2.5 emissions. The PM-10 and PM-2.5 emission rates in the flare modeling appear to contain a serious error.

H. ADEC Applied a Model That Required But Did not Receive EPA Approval

If the recommended models are inappropriate in a given case, other non-guideline models may be used pursuant to 40 C.F.R. § 52.21(l). That section provides that "[w]ritten approval of the Administrator must be obtained for any" non-guideline model. "In addition, use of a modified or substituted model must be subject to notice and opportunity for public comment … ." *Id.*[380]

The applicant and ADEC have applied the Shoreline Dispersion Model (SDM) as part of the air quality modeling analysis. SDM is not listed as an approved air dispersion model under 40 C.F.R. 51 Appendix W.

Anytime modeling for a PSD permit applies a non-guideline model, written approval of the EPA Administrator (or the Administrator's designee) is required. No such approval for SDM has been secured by ADEC and/or the applicant for use in this particular PSD application.

ADEC has claimed that such approval is not required because the SDM was used to "supplement" the AERMOD modeling analysis and AERMOD was in fact the approved model. However, no such distinction for a "supplemental" model is found in 40 C.F.R. 51 Appendix W. Appendix W discusses "Preferred Models" (Section 3.1) and "Alternative Models" (Section 3.2). There are no other categories for models as has been suggested by ADEC. In addition, any

[379] PSD modeling must reflect worst-case emission rates of (i.e., the maximum allow emission rate under the permit) for each pollutant.
[380] 18 AAC 50.040(h)(10), incorporating by reference 40 C.F.R. § 52.21(l).

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attempt to supplement a "preferred model" such as AERMOD would constitute a modification to the approved model. Appendix W specifically prohibits modifying a "preferred" model without subjecting to model to the "alternative model" approval requirements of Appendix W.

Given that SDM is not on the list of EPA "Preferred Models," its use in the Liquefaction Plant PSD permit application is by default as an "Alternative Model." Under Appendix W, the use of any "Alternative Model" is subject to the procedures for EPA Administrator approval listed in Section 3.2 of Appendix W. ADEC's failure to secure written EPA Administrator approval for SDM under the "Alternative Model" procedures means that the PSD permit cannot be issued.

Additionally, ADEC's TAR explains that for characterization of the off-site horizontal stacks in the AERMOD analysis, AGDC used the "POINTHOR and POINTCAP options to characterize the off-site EUs with horizontal/capped stacks,"[381] which ADEC further suggests received the required case-specific approval from EPA.[382] ADEC's proposal does not indicate whether the EPA personnel that approved the alternative was authorized by the agency.

I. ADEC Failed to Consider Secondary PM Impacts

From the information in the TAR, secondary pollutants impacts, such as formation of sulfate and nitrate which would be additive to the primary PM-10 and PM-2.5, were not addressed in the air quality modeling analysis for the AK LNG Project Liquefaction plant. This is critically important in the case of the Liquefaction plant PSD permit, because the modeling of primary PM-10 and PM-2.5 showed results that were at or near the applicable Class II PSD increment at Kenai National Wildlife Refuge, which ADEC explained is approximately 10 km distant.[383] Based on Table 10 in the ADEC TAR, the 24-hour Class II PM-10 modeling listed a modeled concentration of 29.7 micrograms per cubic meter at Kenai versus the Class II PSD increment of 30 micrograms per cubic meter. Similarly, TAR Table 10 lists the modeled PM-2.5 24-hour concentration at 8.7 micrograms per cubic meter at Kenai vs the Class II increment of 9 micrograms per cubic meter.

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[381] PreTAR at 23.

[382] *Id. See also* PreTAR at 4 ("The ambient demonstrations submitted in support of a permit application must comply with the air quality models, databases, and requirements specified of 40 C.F.R. 51, Appendix W (*Guideline on Air Quality Models*), per 18 AAC 50.215(b), or an alternative modeling approach approved under 18 AAC 50.215(c). This basic requirement is reiterated for PSD applicants in 40 C.F.R. § 52.21(l), which the Department has adopted by reference in 18 AAC 50.040(h)(10).")

[383] PreTAR at 32, which further explains that the Class II Sensitive areas subject to evaluation include the Kenai NWR, Chugach National Forest, Lake Clark National Park and Preserve, Kenai Fjords, and Kodiak National Wildlife Refuge.

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Figure 5. ADEC Modeling Analysis Results Demonstrate Impacts At and Near the PSD Increment.[384]

Table 10. Maximum Modeled Impacts Compared to the Class II Increments

Pollutant	Avg. Period	Modeled Design Conc. (μg/m³)	Max. one-hour Fumigation Conc. (μg/m³)	Total Impact (μg/m³)	Class II Increment (μg/m³)
NO_2	Annual	12.5	Included	12.5	25
PM-10	24-hour	24.7	5.0	29.7	30
	annual	2.7	5.0	7.7	17
PM-2.5	24-hour	8.7	Included	8.7	9
	Annual	1.3	Included	1.3	4
SO_2	three-hour	39.6	5.7	45.4	512
	24-hour	17.5	5.7	23.3	91

The modeling results showed no margin of compliance with the Class II PSD increment and it is highly likely that if the increased PM-10 and PM-2.5 associated with secondary emission had been properly considered, the modeling results would in fact have exceeded the applicable Class II PSD increment for PM-10 and/or PM-2.5.

Additionally, ADEC failed to consider impacts from the maritime and terminal NOx and VOC emissions, which must be included in the secondary impacts analysis for PM-10/PM-2.5 and ozone referenced above.

Further, an approach was by EPA for quantification of such impacts, specifically Modeled Emission Rates for Precursors or MERPs.[385] This approach should have been considered by the applicant and by ADEC to address secondary particulate matter (PM) impacts. The draft EPA MERPs report was published in late 2016 and used for PSD permitting upon release.[386] Therefore, the draft 2016 EPA guidance "Draft Guidance on the Development of

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[384] *Id.*

[385] EPA, "Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program," EPA-454/R-19-003 (April 2019), available at https://www.epa.gov/sites/production/files/2019-05/documents/merps2019.pdf.

[386] EPA, "Draft Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program," (Dec. 1, 2016), available at https://nepis.epa.gov/Exe/ZyNET.exe/P100QQWB.TXT?ZyActionD=ZyDocument&Client=EPA&Index=2016+Thru+2020&Docs=&Query=&Time=&EndTime=&SearchMethod=1&TocRestrict=n&Toc=&TocEntry=&QField=&QFieldYear=&QFieldMonth=&QFieldDay=&IntQFieldOp=0&ExtQFieldOp=0&XmlQuery=&File=D%3A%5Czyfiles%5CIndex%20Data%5C16thru20%5CTxt%5C00000001%5CP100QQWB.txt&User=ANONYMOUS&Password=anonymous&SortMethod=h%7C-&MaximumDocuments=1&FuzzyDegree=0&ImageQuality=r75g8/r75g8/x150y150g16/i425&Display=hpfr&DefSeekPage=x&SearchBack=ZyActionL&Back=ZyActionS&BackDesc=Results%20page&MaximumPages=1&ZyEntry=1&SeekPage=x&ZyPURL (this draft guidance was used for PSD permitting upon release).

Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program, was available for use by the applicant on this project well before the PSD application was filed. The EIS appears to have attempted to address secondary PM impacts; however, this effort does not appear to have been carried over into in the PSD permit modeling. Without considering these secondary PM impacts, the liquefaction modeling analysis for the PSD permit is incomplete and underestimated the real-world air quality impacts of the project.[387]

The adjacent Agrium fertilizer facility also should have been considered. Based on Resource Report #9, Appendix D, Agrium has estimated ammonia emissions of approximately 700 tons per year.[388] These ammonia emissions would be expected to react with project-related NOx and SO_2 emissions to form secondary PM in the near-field and increase PM-10 and PM-2.5 above those concentrations explicitly modeled by the applicant. The nearby ammonia emissions, the potential for formation of secondary PM and the associated increase in PM-10 and PM-2.5 concentrations cannot be ignored, especially given that the current PSD permit modeling has virtually no margin of safety with respect to compliance with Class II PSD increments. The secondary PM as described would be additive to the primary PM-10 and PM-2.5 otherwise modeled and these increases would likely cause the Class II PSD increments to be exceeded in the vicinity of the Liquefaction plant.

The transport of nearby ammonia emissions from Agrium would also extend downwind to nearby Class I areas (see separate Class I comments below).

J. The Permit Fails to Include Enforceable Limits to Address Impacts to the AQRVs at the Class I Areas

With respect to required Class I Impact analysis,[389] AGDC's Class I modeling analysis, upon which ADEC's proposed approval relies, clearly documents adverse air quality impacts at both TUXE and DNPP. And while disclosed by ADEQ's PreTAR, the FEIS identified numerous

[387] Furthermore, we note that EPA's Webinar (Jan. 19, 2017)(enclosed and available at https://www3.epa.gov/ttn/scram/appendix_w/2016/MERPs_WebinarPresentation_01192017.pdf) provided detailed information on EPA's rulemaking and revisions to the Guideline on Air Quality Models (82 Fed. Reg. 5182 (Jan. 17, 2017) (Revisions to the Guideline on Air Quality Models: Enhancements to the AERMOD Dispersion Modeling System and Incorporation of Approaches To Address Ozone and Fine Particulate Matter.) EPA's final rulemaking webinar cited to the 2016 MERP guidance documents as to the recommended procedures for the secondary pollutants analysis. The Appendix W guidelines are in Section 5.3 for ozone and Section 5.4 for PM-10/PM-2.5. While Appendix W Section 5.4 refers to PM-2.5, since PM-2.5 is a subset of PM-10, the secondary PM-2.5 determined by the MERPs procedure is also additive to the PM-10 modeling. Finally, EPA's proposed rulemaking further discussed the purpose of MERPs for ozone and secondary $PM_{2.5}$ precursors in the permitting context. 80 Fed. Reg. 45340, 45348 (July 29, 2015)

[388] Based on information included in ADEC's proposed approval of Agrium's recently submitted request for a new PSD permit to construct, if permitted and constructed, the potential to emit for ammonia would be 634 tpy. See, Agrium Permit Application at PDF 182.

[389] 18 AAC 50.306(h)(4). which adopts 40 C.F.R. § 52.21(p) by reference.

exceedances of sulfur and acid deposition thresholds, nitrogen deposition thresholds and visibility thresholds.[390]

Given these impacts, ADEC was required to – and did not – consult with and address FLM concerns prior to providing public notice on its proposed permit action,[391] which we discuss elsewhere in our comments. Moreover, if the proposed action will likely cause or contribute to an adverse effect to air quality related values, the federal land manager (FWS or the NPS may recommend permit conditions that ensure mitigation, including stricter emissions controls and effective emissions offsets. If no mitigation is possible, NPS or FWS may recommend denial of the permit.[392] While this is a procedural error, more importantly the fact the ADEC did not follow the procedures to consult with the FLMs **before proposing the permit** means that ADEC failed to address FLM comments and concerns regarding the significant AQRV impacts at the national park and wilderness area in its proposed permit action.

As Mr. Gebhart's report explains, ADEC acknowledges in the PreTAR that the proposed project will adversely impact the Class I areas. But then ADEC then goes on to assert that such adverse impacts were not of regulatory significance. In the first part of its analysis, ADEC attempts to characterize the results from the VISCREEN analysis at the Kenai NWR as "negligible."[393] ADEC basis its characterization on the following assertions: accurate model inputs were used; and "the relative isolation of these estimated deviances at a Class II Sensitive area is not sufficient to warrant further regulatory inquiry, *ceteris paribus*."[394] Finally, ADEC

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[390] *See* FEIS at 4-943 (nitrogen deposition impacts from gas treatment plant would exceed deposition thresholds for the Arctic National Wildlife Refuge ("the Refuge")); id. at 4-955 (sulfur deposition thresholds could be exceeded by air emissions from the Galbraith Lake Compressor Station at the Refuge); id. at 4-974 (LNG emissions "could have a long-term significant impact on acid deposition at the Tuxedni NWR, DNRR, Kenai NWR, and Lake Clark NPP"); id. at 4-958, Tbl. 4.15.5-19; 4-955 ("compressor station and heater station operation could have significant impacts on ecosystems from nitrogen deposition in Class I and Class II nationally designated protected areas"); id. at 5-42 ("the FLM-established visibility threshold and sulfur deposition threshold at the Arctic National Wildlife Refuge could be exceeded by emissions from the Galbraith Lake Compressor Station. FLM-established nitrogen deposition thresholds at multiple Class I and II areas—including Arctic National Wildlife Refuge, Gates of the Arctic NPP, Gates of the Arctic Preserve, Yukon Flats NWR, Kanuti NWR, DNPP, and Kenai NWR—could also be exceeded by operation of the stations").146 Such emissions would also harm visibility in these areas, degrading the quality of recreation. See, e.g., FEIS at 4-943 (visibility impacts from the gas treatment plant could exceed threshold at the Refuge); id. at 4-943 (identifying cumulative impacts to visibility in the Refuge and Gates of the Arctic National Park and Preserve); id. at 4-946 (gas treatment plant emissions would exceed the visibility change threshold at the Refuge and "could have a long-term significant impact on regional haze at [the Refuge]"); id. at 4-974 (LNG emissions could have a significant impact on regional haze at the Kenai NWR); id. at 4-955 (visibility plume perceptibility thresholds could be exceeded by the Galbraith Lake Compressor Station at the Refuge and by the Healy and Honolulu Creek Compressor Stations at the Denali National Park and Preserve).

[391] For example, the FLMs evaluate visibility impacts are evaluated by looking at the change in light extinction due to pollution. Light extinction is a measure of visibility reduction (degradation) and is inversely proportional to visual range. According to the "Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report," (2010), Natural Resource Report NPS/NRPC/NRR-2010/232, impacts that change light extinction by more than 5% would be considered to contribute to visibility impairment and impacts that change light extinction by more than 10% would be considered to cause visibility impairment, available at https://www.fws.gov/guidance/sites/default/files/documents/FLAG%20Air%20Quality%20Phase%201%20report.pdf.

[392] *Id.* at 66-67.

[393] PreTAR at 33.

[394] *Id.*

concludes that, "the Department finds AGDC's modeled results sufficient to provide a reasonable estimation of immaterial near-field visibility impacts."[395]

We have numerous concerns with ADEC's analysis of the VISCREEN results. First, ADEC merely labels the results as "negligible" neither providing a frame of reference nor explaining why the results are negligible. Further, the PreTAR fails to present the actual results, and fails to include a reference to where information on the results is found,[396] presenting the adverse impacts as follows:

- A slight deviation from both criteria for the compressor turbine plumes, subject to sky background and backward scatter, at the closest park boundary observer location; and
- An increase in the perceptibility criteria for the compressor turbine plumes, subject to terrain background and forward scatter, at both the closest park boundary and Skilak Lake observer locations.[397]

Second, as discussed below and throughout our comments, the assumptions used to create the model inputs – from the flawed determination of what constitutes the source, to the detailed modeling inputs and methodology – have serious flaws that are inconsistent with the regulations and Act. Thus, it is unreasonable for ADEC to suggest that the model inputs were "representative-to-conservative" as they clearly were not. Finally, we disagree with ADEC's assertions that the model results are just mere "deviances" because they come from model estimations. ADEC's assertion is not supported by any rationale. For example, ADEC fails to explain or justify "deviations," the relevance of its finding that they are in "relative isolation," or explain its concerns regarding what it perceives to be model inaccuracies. Such bare assertions without supporting rationale are arbitrary and unreasonable. Additionally, presenting the modeling results as "exceptions" is illogical and unsupported.[2] The results stand. ADEC provides no support for its a theory that the results from these modeling runs are not consistent with what one would expect from VISCREEN, which is not surprising since models are predictive in nature and moreover, can only be used in this context if they have been approved for use by EPA. Moreover, while uncertainty is inherent to the modeling process, models are the tools Congress specified for use in this context and are what is used by agencies to make permitting decisions. Thus, ADEC cannot supplant the VISCREEN modeling results and meet the purposes of the PSD program based on its proposal.[398]

ADEC's Class I AQRC analysis next considers the "source-only" results from the CALPUFF model, explaining that the model showed impacts "to both Class I and Class II Sensitive areas, in terms of regional haze and visibility degradation." ADEC's attempts to discount the following results as "immaterial" are also unavailing:

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[395] PreTAR at 33.

[396] A permitting agency must present information for public review in a clear manner. ADEC goes at great lengths in other portions of its PreTAR to present the fine details, and yet when it comes to the AQRV impacts at the Class I and Class II areas, neither details nor a citation as to where one can find the information are provided.

[397] PreTAR at 33.

[2] *Id.* at 33.

[398] Furthermore, ADEC's discussion fails to include the FLMs comments and concerns regarding these adverse AQRV impacts to the lands they have an affirmative to protect.

- For **regional haze** the modeling results showed impacts to both Class I and Class II Sensitive areas,
- For **visibility degradation** the modeling results showed impacts to both Class I and Class II Sensitive areas, and
- The **deposition analysis** indicates sulfur and nitrogen flux results above the respective deposition analysis thresholds (DATs) at several locations.

We disagree with ADEC's supporting discussion of the CALPUFF results based on the following. In assessing the impacts to regional haze and visibility, ADEC divides the impacts into two categories and characterizes them as follows: (1) "slight exceedances [of regional haze and visibility degradation] at Lake Clark National Park in model years 2003 and 2004;"[399] and regional haze and visibility impacts to "both Class I and Class I sensitive areas … that fall below the five-percent extinction threshold at all areas evaluated."[400] As they neglected to do in the VISCREEN analysis, ADEC fails to include any of the model results in the PreTAR and does not provide a reference where the public can review the information. The suggestion that impacts are "slight" is unsubstantiated, ADEC does not explain what the actual results show, why they are "slight" and how the results compare to some apparent metric upon which they assess impacts. Further, in mentioning the exceedances were only found in two of the model years (2003 and 2004), without providing any justification, ADEC appears to further discount the results. This is illogical. The CALPUFF model is run over a series of years of meteorological data to represent a variety of conditions. The fact that exceedances are seen in some years and not others is not an anomaly since weather patterns change from one year to the next. ADEC further offers that for all the Class I and Class II Sensitive areas impacted – with the exception of Lake Clark National Park – "regional haze and visibility degradation … fall below the five-percent extinction threshold."[401] ADEC does not explain the basis for using this threshold, nor does it explain how close the results are to this threshold. Without explaining what "cumulative values" it refers to, ADEC further suggests that it understands

> [T]hese cumulative values may be compelling when considered in the absence of additional information.[402]

Although ADEC suggests there is "additional information," in reality none is provided. First, without explaining how and why plant operation impacts its decision, ADEC suggests "there is no cause for regulatory concern at the former areas with regard to significant visibility impairment attributable to operation of the Liquefaction plant as proposed."[403] Moreover, ADEC's next piece of information is also unreasonable, it offers that "mode uncertainty and conservative operational assumptions suggest estimated impacts attributable to the Liquefaction plant may be overstated."[404] There is nothing to support this statement. The public is left wondering: what does ADEC mean by "mode uncertainty" … and by "conservative operational assumptions … and how does the uncertainty and operational assumptions relate to the CALPUFF model inputs? None of this information is disclosed. For a permitting agency to rely on source operating parameters to limit

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[399] PreTAR at 33-34.
[400] PreTAR at 34.
[401] PreTAR at 33-34.
[402] *Id.* at 34.
[403] *Id.*
[404] *Id.*

emissions and thereby protect the AQRVs, ADEC must disclose what "mode" and "operation" it assumes, and include those assumptions in the proposed permit. Providing a clear link between the assumptions made and how they will be enforced under the Act. None of which is provided in ADEC's proposal.

Finally, ADEC's PreTAR attempts to explain why the acidic deposition impacts are immaterial. The sulfur and nitrogen flux results are neither included in the PreTAR, nor has the ADEC indicated to the public where it can find them. ADEC discloses that the "sulfur and nitrogen flux results above the respective deposition analysis thresholds (DATs) at several locations," but does indicate the locations impacted. Without explaining what this means, ADEC notes that "Denali is the only Class I area among the former."[405] ADEC next attempts to discount the results by suggesting the impacts from sulfur are higher than those from nitrogen. Since impacts from both are above the threshold, all impacts are of concern, it is unreasonable for ADEC to suggest otherwise. Further, without describing what the "cumulative deposition analysis" included, nor where one can find the results, ADEC suggest "the results are below the DAT at all locations."[406] ADEC's suggestion that by relying on "potential" qualities in the natural-gas and "operational assumptions" "would likely obviate the sulfur deposition concerns at the Class II Sensitive areas modeled."[407] ADEC does not provide any details on what it suggests relying on. It does not provide the basis for "AGDC's position" regarding potential for gas that is different than what was modeled. Further, ADEC points to nothing in the permit that reflects this assumption. Moreover, it is similarly unclear what and how "operational assumptions" might impact the areas modeled; and further no explanation of whether those operational assumptions are reflected in the proposed permit. ADEC also offers that the nitrogen impacts would also be mitigated by "said conservativism of operational assumptions, largely predicated upon AGDC's greater than anticipated 'normal' modeled operational scenario."[408] ADEC's attempt to discount the nitrogen impacts fail for the same reasons outlined above. Further, neither AGDC nor ADEC present revised modeling results to support the myriad of assumptions.

Furthermore, FERC's FEIS discloses that it issued information requests requesting that AGDC provide information about the "mitigation strategy."[409] It appears AGDC did not respond to FERC's request.

In sum, ADEC cannot proceed with the Liquefaction plant PSD permit without first addressing the adverse Class I impacts that have been identified. ADEC should have fully disclosed to the public the FLM findings when it proposed the permit and required adoption of appropriate measures to address the adverse impacts and made implementation of such measures enforceable permit requirements. As presented in the Draft PSD permit and PreTAR, ADEC has not fulfilled its regulatory and statutory obligations to protect AQRVs and other resources in the affected Class I areas. Furthermore, not only has ADEC failed to meet these requirements, as discussed in the next section, the methodology upon which ADEC relied is incomplete, inaccurate and inconsistent in its assumptions.

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[405] *Id.*
[406] *Id.*
[407] *Id.* ("The Department notes that AGDC's position regarding an in-situ potential for "sweeter" than modeled pipeline-quality fuel gas and conservative operational assumptions.)
[408] *Id.*
[409] *See* FEIS at 4-943 ("While preparing the draft EIS, we issued information requests on July 28, 2017 and February 15, 2018 to AGDC requesting that they work with the FLMs to establish a mitigation strategy to ensure that air emissions from the proposed facilities would not negatively affect nearby Class I and Class II nationally designated protected areas. To date, AGDC has not provided a mitigation strategy or determined acceptable thresholds agreed upon by the FLMs.").

K. The Class I Modeling Analysis Is Incomplete, Inaccurate and Inconsistent in its Assumptions

Notwithstanding the above, the Class I modeling has technical errors and the result is that Class I impacts at TUXE and DNPP have been underestimated. These technical errors are documented below.

The cumulative air quality modeling was incomplete with respect to Class I impacts. For example, the modeling for the Liquefaction plant did not completely address all project-related impacts to Denali National Park and Preserve (DNPP). Several of the pipeline compression facilities associated with the AK LNG Project would be in close proximity to DNPP. For example, the Healy Compressor Station would be located within 5 kilometers of DNPP and the Honolulu Creek Compressor Station would be located within 14 km of DNPP. Based on the data presented in the TAR, the pipeline compressor station emissions were not included in the Class I air quality modeling. However, these compressor stations emissions are part of the AK LNG Project and their impacts should have been evaluated. Also, any such emissions would occur after the PSD minor source baseline date and as such, would consume PSD increment at nearby Class I areas such as DNPP. Likewise, these emissions have the potential to adversely impact AQRVs such as visibility and acid deposition. The compressor station emissions needed to be addressed in combination with the Liquefaction plant for the Class I analysis at DNPP; otherwise, the analysis was incomplete with respect to air quality impacts, including PSD increment along with air quality related values (AQRVs) such as visibility and acid deposition.

In the CALPUFF modeling, the selected years for meteorological data and other inputs was 2002-04. As such, the background ozone data used in CALPUFF were also from 2002-04, which meant that the ozone data input to CALPUFF were more than 15 years old. The CALPUFF modeling should have been based on more recent data so that it would be representative of current conditions.

The CALMET modeling used to derive the CALPUFF meteorological fields was not consistent with current EPA/FLM guidelines (See: Clarification on EPA-FLM Recommended Settings for CALMET; USEPA Memo dated August 31, 2009). For example, the vertical layers assigned in CALMET/CALPUFF did not match the 2009 EPA/FLM guidelines. There may have been other deviations from the 2009 EPA/FLM guidelines, but that could not be determined from the information presented in Resource Report No. 9, Appendix D.

As noted in earlier comments above, errors exist in specification of emissions associated with flaring as well as emissions associated with maritime traffic. These errors also translate to the Class I modeling analysis.

Finally, as noted in comments above, the Agrium fertilizer plant located adjacent to the Liquefaction plant site is a very large source of ammonia emissions. It is likely that these ammonia emissions would be transported along with emissions from the proposed Liquefaction plant to nearby Class I areas. The ammonia emissions would interact with the Liquefaction plant

NOx and SO_2 emissions to form ammonium sulfate and ammonium nitrate during the downwind transport to these nearby Class I areas and cause increased impacts to AQRVs such as visibility and acid deposition. This is contrary to the applicant's claims in the CALPUFF modeling that the Liquefaction plant emissions would exist in an ammonia-limited environment. The ammonia emissions associated with the adjacent Agrium plant were not considered in the Class I impact modeling relied upon by ADEC. As such, the reported impacts to Class I areas such as DNPP and TUXE were underestimated.

L. ADEC's Public Notice Failed to Provide the Degree of Increment Consumption Expected at the Source at the Class I Areas

The Clean Air Act requires meaningful public participation in the PSD permitting process. Section 165(a)(2) requires a public hearing allowing for interested persons "to appear and submit written and oral presentations on the air quality impact of such source, alternatives thereto, control technology requirements, and other appropriate considerations." In implementing this provision, ADEC adopts EPA's regulations defining the requirements for state PSD plans, which require the reviewing authority to:

> Notify the public, by advertisement in a newspaper of general circulation in each region in which the proposed source would be constructed, of the application, the preliminary determination, *the degree of increment consumption that is expected from the source or modification*, and of the opportunity for comment at a public hearing as well as written public comment.

40 C.F.R. § 51.166(q)(2)(iii) (emphasis added).[410] ADEC's public notice for the draft permit was defective because it failed to include the predicted amount of increment consumption in the Class I areas. The regulation specifically requires these data to be in the public notice. "To allow for meaningful comment, the public must be apprised of all of the proposed source's increment consumption as determined through the modeling analysis."[411] Furthermore, "[d]ifferent potential commenters may have an interest in different areas to be impacted and would want, and would reasonably be entitled to, available data on increment consumption at the area of their particular concern. Otherwise, their ability to comment on the air quality impact and proposed alternatives would be severely limited."[412] Therefore, ADEC should "provide a new public notice … and such notice should detail all of the increment to be consumed by the proposed source, including any increment consumed"[413] at the Class I areas.

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[410] ADEC adopts many of the PSD regulations by reference, including this one. EPA last approved ADEC's adoption by reference in 2014, when ADEC adopted the version of this rule [via 18 AAC 50.040(h)(2)] that was revised by EPA as of July 1, 2011. 79 Fed. Reg. 56268 (Sept. 19, 2014).
[411] *Hadson Power* at 272.
[412] *Id.*
[413] *Id.*

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M. ADEC Erred in Categorically Excluding Construction Emissions from the Air Quality Analysis.

Section 165(a)(3) of the Clean Air Act, provides that no major emitting facility may be constructed unless "the owner or operator of such facility demonstrates … that emissions from construction or operation of such facility will not cause or contribute to air pollution in excess of [any applicable PSD increment or national ambient air quality standard.]." In addition, the Clean Air Act prohibits construction, not just operation, prior to permit issuance. In addition to the language of section 165(a)(3) itself, the requirement to consider construction emissions is clearly demonstrated by the inclusion of "construction" throughout the PSD regulations.[414]

Construction emissions were not modeled for the PSD permit. However, given the duration of construction anticipated to be eight years and the phased nature of construction for the proposed activity included in this permit and the other emitting units that must be made part of this source, as Mr. Gebhart's Report explains, it should be apparent that construction of later project phases would overlap with initial project operations. ADEC's analysis needs to address modeling scenarios where project construction would overlap with the initial project operations in order to provide for a full and complete air quality modeling analysis.[415] As discussed above, ADEC must first obtain the applicants construction schedule in order to conduct this analysis. If the modeling does not include construction emissions and acknowledge the likely overlap with startup and operation emissions, it will be inaccurate and misleading.[416]

Mr. Gebhart's Report further notes that it is not enough that the permit has included PM-10 and PM-2.5 monitoring requirements during the construction phase … these monitoring requirements only provide for measurements against the NAAQS, and fail to assure that the permit conditions will actually protect the NAAQS. Furthermore, the construction-related emissions would occur after the minor source baseline date and as such, the construction emissions also consume PSD increment and were not included in the increment analysis. The monitoring program contemplated under the permit would not be capable of demonstrating whether the construction-related emissions might cause or contribute to possible violations of the Class II PSD increment for PM-10 and PM-2.5. Therefore, an accurate PSD increment assessment that addresses construction-related emissions is required, which would be best achieved through air quality modeling conducted in accordance with the Modeling Guideline and other requirements.

N. ADEC Erred in Equating the Soils and Vegetation Impact Analysis with the NAAQS Analysis

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[414] *See e.g.,* 40 C.F.R. 52.21(b)(2), (b)(48)(iii).
[415] Gebhart Report at 11.
[416] Notably, the revised construction schedule AGDC provided during the DEIS comment period led to the disclosure in the FEIS that simultaneous construction, startup, and operation of the Liquefaction Facilities "could lead to short-term air quality impacts" such that a monitoring plan would need to be implemented to monitor air quality and manage exceedances. FEIS, App. CC at CC-583; *see also* Order ¶ 210.

The PSD regulations require that the permit applicant "provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source … and general commercial, residential, industrial and other growth associated with the source … ." 40 C.F.R. § 52.21(o). This requirement is often referred to as the "additional impacts analysis." The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value." 40 C.F.R. § 52.21(o)(1); *see In re Kawaihae Cogeneration Project*, 7 E.A.D. 107, 130 (EAB 1997). Generally, the additional impact analysis consists of four parts: (1) impairment to visibility; (2) soils and vegetation impacts; (3) ambient air quality impact; and (4) growth expected as result of the source or modification. *See* 40 C.F.R. § 52.21(o). For the impacts to soils and vegetation, the permitting authority must consider the impacts of growth associated with the proposed Liquefaction plant as well as the impacts of pollutants for which there are no NAAQS. The PreTAR acknowledges these requirements.[417]

For the soils and vegetation analysis, the ADEC PSD permit analysis relies solely on compliance with NAAQS to address possible adverse impacts to soils and vegetation. This approach is wholly inadequate. The NAAQS do not cover all pollutants and therefore are not intended to be protective of all soils or all vegetation species. If the NAAQS adequately protected all species from harmful effects of air pollution, there would be no need for the separate soils and vegetation analysis required by the PSD regulations at 40 C.F.R. § 52.21(o)(1).[418] Instead, ADEC should instruct the applicant to inventory soils and vegetation species present in the area impacted by the entire AK LNG Project to determine the presence of species that may be particularly sensitive to adverse impacts from air pollution.[419] Special attention should be paid to any threatened and endangered species that exist in the region. The EIS already contains local/regional data on soils and vegetation that could assist in conducting a soils and vegetation assessment consistent with the basic requirements of the underlying PSD regulations.[420] Relatedly, Appendix Q contains the "Recreation Areas Affected by the Project," and it could also assist in analyzing the impairment to vegetation of recreational value and well as other reports prepared.[421]

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[417] PreTAR at 35. And while ADEC acknowledges these regulations, explains that "AGDC it did not include Pipeline Stations and Gas Treatment Plant [nor any other sources that comprise the Alaska LNG Project) in their Associated Growth Analyses since those stationary sources will not be located in the same area as the Liquefaction Plant. As previously noted in Section 5.6.3 of this report, the ambient impacts associated with each of those stationary sources will be assessed, as warranted, under the permit requirements for that stationary source." *Id.* For the reasons described earlier in these comments, we also disagree with ADEC's unsupported assertion here.

[418] 18 AAC 50.040(h)(10), incorporating by reference 40 C.F.R. § 52.21(o)Additional impact analyses.
(1) The owner or operator shall 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. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.
(2) The owner or operator shall provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source or modification.
(3) Visibility monitoring. The Administrator may require monitoring of visibility in any Federal class I area near the proposed new stationary source for major modification for such purposes and by such means as the Administrator deems necessary and appropriate.

[419] Gebhart Report at 11.

[420] FEIS at 4-943.

[421] FEIS, Appendix Q, included as an enclosure. Additionally, the following could also assist with this analysis and are included with these comments: FEIS Appendix O (information on critical habitat, which could also assist in

Additionally, for several of the facilities that must be considered part of this PSD permit analysis, the Final EIS explains that there would be the following impacts as Class I and Class II areas

- Operation of the Galbraith Lake Compressor Station could have a significant plume impact at ANWR[422]
- Compressor station and heater station operation could have significant impacts on ecosystems from nitrogen deposition in Class I and Class II nationally designated protected areas[423]
- Nitrogen deposition impacts from gas treatment plant would exceed deposition thresholds for the ANWF[424]
- Emissions from the aboveground facilities, including the GTP, compressor stations, heater station, and Liquefaction Facilities, could cause exceedances of visibility extinction thresholds[425]
- Sulfur deposition thresholds could be exceeded by air emissions from the Galbraith Lake Compressor Station at the Refuge,
- LNG emissions *could have a long-term significant impact on acid deposition at the Tuxedni NWR, DNRR, Kenai NWR, and Lake Clark NPP.*[426]

Moreover, despite these impacts, no "additional mitigation measures" as identified in the analysis upon which AGDC relied for its permit application,

O. ADEC's Use of Sensitivity Modeling Fails

ADEC uses sensitivity modeling in an attempt to demonstrate that the errors introduced by not following the current Guideline did not significantly impact the modeling results and that not following the Guideline shouldn't matter. As discussed in Mr. Gebhart's report and presented here, ADEC's attempt to defend the flawed modeling using a sensitivity analysis similarly fails.

The underlying air quality modeling reports from the AK LNG Project EIS (and by extension, the Liquefaction plant PSD permit) were outdated. The Appendices to Resource Report No. 9 that described the air quality modeling methods and results dated to 2017, and in some cases, the actual modeling studies described in Resource Report No. 9 were even older.

There are significant issues with using outdated air quality modeling studies. First, the

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considering the impacts); FEIS Appendix P (special status species list, which includes the region impacted, habitat impacted, as well as what portion of the proposed AK LNG Project will impact a particular species and the potential impacts); FEIS Appendix V (includes and relies of information on the potentially affected communities, which could be used to assist in analyzing the air quality impact of the AK LNG Project as a result of general commercial, residential, industrial and other growth associated with the source); FEIS Appendix Z includes a list of more than one hundred pages of references, at approximately 10 references per page, no doubt that information could also assist.)

[422] FEIS at 4-673.

[423] *Id.* at 4-955.

[424] *Id.* at 4-955

[425] Id. at 4-955.

[426] *Id.* at 4-974.

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EPA models used for the Draft EIS air quality impact assessment have been revised and newer versions of the air quality models such as AERMOD and CALPUFF have been released by EPA. Also, using outdated information adversely impacted the cumulative modeling studies in that new emission sources not previously identified may have been constructed and/or proposed since the air quality modeling studies were conducted. In addition, emissions at off-site modeled sources may have changed. The air quality modeling studies need to: 1) use the current versions of the EPA dispersion models and 2) model cumulative air quality impacts using current and relevant emissions data.

To some extent, ADEC recognized that flaws existed from using the outdated EIS modeling analysis. ADEC then conducted so called "sensitivity studies" in a misguided attempt to defend the flawed modeling. However, the ADEC "sensitivity studies" were themselves flawed in several major respects: 1) these studies were limited in that they were applied only to a small subset of the EIS modeling results, 2) these studies looked at modeling errors on an individual basis and did not address the potential cumulative effect of all relevant modeling errors, and 3) the sensitivity studies did not address all modeling errors that carried over from the EIS.

ADEC's own permit review analysis recognized that the EIS modeling was technically deficient and not up to current standards for a PSD permit. ADEC should have instructed the applicant to update the modeling so that the permit could rely on modeling results that were created under current modeling procedures and standards. Instead, ADEC erroneously chose a convoluted process to defend its reliance on outdated dispersion modeling created for the EIS.

P. ADEC's Modeling Analysis Failed to Address Secondary Emissions Associated from Growth Impacts

Secondary emissions are defined as:

> [E]missions 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 … itself. Secondary emissions include emissions from any off-site support facility which would not be constructed or increase its emissions except as a result of the construction or operation of the major stationary source ….[427]

Secondary emissions arise from residential, commercial and industrial growth that accompanies the new activity at the source.[428] For PSD review, "[s]econdary emissions must be specific, well-defined, quantifiable, and impact the same general area as the stationary source … undergoing review."[429]

ADEC's proposal suggests that

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[427] 40 C.F.R. § 52.21(b)(18). 18 AAC 50.040(h)(4)(adopts by reference the definitions in 40 C.F.R.§ 52.21(b), which includes the definition of secondary emissions in 40 C.F.R. § 52.21(18).
[428] 40 C.F.R. § 52.21(o).
[429] *In re Encogen Cogeneration Facility*, 8 E.A.D. 244, 258 (EAB 1999), citing *Knauf I* at 166 (quoting NSR Workshop Manual at A. 18)(internal quotations omitted); *see also* 54 Fed. Reg. 27,286, 27,289 (June 28, 1989).

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> The only secondary emissions that would occur due to the construction and operation of the Liquefaction plant are the construction emissions that would occur within the local area. The emissions that would occur due to the remaining aspects of the AK LNG Project, including the construction/operation of the Pipeline Stations and the Gas Treatment Plant, are not secondary emissions for purposes of the Liquefaction plant PSD review since they will not occur in the same general area as the Liquefaction plant emissions.[430]

ADEC's analysis and proposed conclusions regarding the need to address secondary emissions associated with construction and operation are misplaced. As presented earlier in these comments, not only is it inconsistent with the PSD regulations to exclude emitting units in the source determination, it is similarly inconsistent to ignore them when analyzing impairment to visibility, soils and vegetation that would occur as a result of the source and general commercial, residential, industrial and other growth associated with the source growth impacts. Once a proper source determination is made, the "general area" of the stationary source includes the general area around all the emitting units that comprise the AK LNG Project. Contrary to ADEC's assertions, the "area" is not limited to the Liquefaction plant. Furthermore, ADEC references an EPA memo from 1981, suggesting that EPA's guidance clarifies that for purposes of the secondary emission inventory

> [T]he 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."[431]

The guidance ADEC refers to in its footnote is an EPA letter from Edward F. Tuerk (Acting Assistant Administrator for Air, Noise and Radiation) to Allyn M. Davis (Director, Air and Hazardous Materials Division), regarding "PSD Evaluation of Secondary Emissions for Houston Lighting and Power." Although ADEC did not include a citation to where the memo can be found or the memo in its proposed action, we found the memo in EPA's "New Source Review Prevention of Significant Deterioration and Nonattainment Area Guidance Notebook," Volume I, dated January 1989.[432] In applying the phrase "impact the same general area," EPA's memo explained that "the scope of any required analysis haw to be limited to those areas where both secondary and primary emissions are known to occur."[433] To summarize:

> EPA's 1981 memo addressed the question of whether emissions from the mine mouth plant needed to be included in the power plant's modeling analysis. Additionally, the memo looked at the provisions for Total Suspended Particulate Matter (TSP) and SO_2 impacts at Class II and Class III areas as set forth in EPA's Emission Offset Interpretive Ruling and the preamble to the 1978 PSD regulations (43 Fed. Reg. 26398 (June 19, 1978)), noting that the mine and power plant were under different ownership.

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[430] PreTAR at 5.
[431] PreTAR at 17.
[432] A copy of this guidance enclosed.
[433] EPA, "New Source Review Prevention of Significant Deterioration and Nonattainment Area Guidance Notebook," Volume I (Jan. 1989), Edward F. Tuerk (Acting Assistant Administrator for Air, Noise and Radiation) to Allyn M. Davis (Director, Air and Hazardous Materials Division), regarding "PSD Evaluation of Secondary Emissions for Houston Lighting and Power," at PDF 411-412 (March 17, 1981).

> Furthermore, the modeling analysis performed demonstrated that the proposed power plant would not cause a significant ambient concentration of TSP at any of the Class II and Class III areas. Thus, the memo recommended that it was not necessary to consider the emissions from the mine as secondary emissions since they do not impact any area of significant impact which would be created by the direct emissions from the proposed power plant.[434]

The facts in EPA's 1981 memo are clearly inapposite to the AK LNG Project (as well as the proposed Liquefaction plant). EPA's memo looked at two sources under different ownership, while the AK LNG Project is all under the same ownership. Additionally, modeling done for the question raised back in 1981 showed the proposed power plant did not impact any areas, where that is not the case here. Thus, ADEC's suggestion that EPA's 1981 memo supports excluding emissions based on this secondary emissions theory fails.

Q. ADEC's Assessment of NAAQS Exceedances Differs from FERC's

While both ADEC and FERC relied on the same modeling analysis, the two agencies differ in whether the proposed AK LNG Project will cause exceedances of the NAAQS FERC's FEIS discloses that

> During the years that simultaneous construction, startup, and operational activities would occur at the Liquefaction Facilities, which would **likely be Years 7 and 8 of construction, emission levels could result in exceedances of the NAAQS/AAAQS**. AGDC developed and would implement an Ambient Air Quality Monitoring Plan to ensure the emissions associated with simultaneous construction, startup, and operational activities would not result in exceedances of PM10 and PM2.5 ambient air quality standards.[435]

While ADEC asserts that "AGDC's far-field model results, both source-only and cumulative, indicate estimated ambient concentrations within the modeled areas of Page 33 of 38 concern fall below the respective increments; no violations of the NAAQS/AAAQS are seen."[436] Although this assertion from ADEC is in a paragraph referring to the FERC Report, ADEC fails to provide a citation. It is deeply concerning that ADEC neither disclosed nor addressed these predicted public health impacts.

Furthermore, FERC discloses that overall "[p]roject operation would have a permanent effect on air quality in the vicinity of the aboveground facilities associated with the Project,"[437] while also recognizing in its Order that "measures could be implemented by the State of Alaska during the air permitting phase that would reduce these impacts."[438]

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[434] *Id.* at 412
[435] FEIS at 4-975
[436] PreTAR at 32-33.
[437] *Id.*
[438] FERC Order ¶ 209.

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R. ADEC's Proposed Permit Fails to Include Enforceable Permit Conditions That Reflect the Ambient Air Boundary Modeling Assumptions

"AGDC used the proposed fenced perimeter around the Liquefaction plant as an ambient air quality boundary for the on-shore facility area … excluded the marine vessel loading berths and trestle areas from ambient air assuming a 500-foot stand-off distance predicated upon reasonable and enforceable safety requirements."[439] ADEC's proposal indicates that the "AAAQS and increments only apply in ambient air locations, which has been defined by EPA as, '…that portion of the atmosphere, external to buildings, to which the general public has access.'"[440] ADEC further explains that, "[a]pplicants may, therefore, exclude areas that they own or lease from their ambient demonstration if public access is "precluded by a fence or other physical barrier."[441]

ADEC suggests that "[t]he former element of AGDC's approach offers a clear means to preclude the public from ambient air … [t]he latter element of this approach, while not supported by explicit and quantifiable air quality guidance, is rooted in practical precedent."[442] ADEC finally explains that

> The Department's discussion in the Ambient Boundary section of its Modeling Report for PacRim Coal, LLC's Chuitna Project, Minor Permit AQ0957MSS03, offers relevant detail regarding the exclusion of vessel loading activities from ambient air. AGDC's approach to exclude select areas from ambient air is appropriate for the Liquefaction plant ambient analysis.[443]

As an initial matter we point out that ADEC neither provided a reference to nor the documents where its prior discussion on Ambient Boundary could be found, thus we were unable to review that information. Furthermore, the proposed permit lacks requirements that AGDC effectively restrict access to the plant site. Therefore, ADEC "must impose requirements in the permit that would force" AGDC "to erect appropriate barriers or to take other measures that would effectively preclude public access."[444] Without such enforceable requirements it is unreasonable for ADEC to use the property boundary in modeling impacts and ADEC's proposed decision essentially allows AGDC to emit more pollution, and possibly with fewer controls, than would otherwise be lawful.

Similarly, the proposed permit lacks any enforceable conditions covering the 500-foot stand-off distance for the marine loading berths and trestle areas, and without enforceable

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[439] PreTAR at 28.
[440] PreTAR at 27, explaining that "[t]he term "ambient air" is defined in 40 CFR 50.1. The Alaska Legislature has also adopted the definition by reference in AS 46.14.90(2)."
[441] *Id.* at 29, explaining that "EPA has written a number of guidance documents regarding ambient air issues which may be found in their Modeling Clearinghouse Information Storage and Retrieval System (http://cfpub.epa.gov/oarweb/MCHISRS/). The documents routinely use the phrase "fence or other physical barrier" when discussing an acceptable means for precluding public access at onshore locations. The phrase originated in a December 19, 1980 letter from EPA Administrator Douglas Costle to Senator Jennings Randolph."
[442] *Id.*
[443] PreTAR at 27-28 (citation omitted).
[444] *In the Matter of Hibbing Taconite Company,* 2 E.A.D. 838 (EAB 1989).

requirements we have the same concerns identified above. Therefore, ADEC's permit must include terms and conditions to ensure the source actually takes steps to preclude public access from these areas, that the plan be in writing and subject to ADEC's approval.[445]

VII. The Draft Permit's Terms and Conditions Are Insufficient to Ensure Compliance with the Clean Air Act

A. ADEC Allows for Use of Alternative Test Methods that are not EPA-approved

- Permit Condition 4.2 the stationary source's projected annual rate of emissions that will occur from July 1 to the following June 30, based upon credible evidence of actual annual emissions emitted during the most recent calendar year or another 12 month period approved in writing by the Department, when demonstrated by the most representative of one or more of the following methods:

  d. *other methods and calculations approved by the Department*, including appropriate vendor-provided emissions factors when sufficient documentation is provided.[446]

- Permit Condition 35.7 Source testing for emissions of any contaminant may be determined *using an alternative method approved by the Department* in accordance with 40 C.F.R. 63 Appendix A, Method 301.[447]

- Permit Condition 36. Test Deadline Extension. The Permittee may request an extension to a source test deadline established by the Department. The Permittee may delay a source test beyond the original deadline only if the extension is *approved in writing by the Department's* appropriate division director or designee.[448]

B. The proposed permit allows for amendments to the permit that the public will not have an opportunity to review and comment on

The following permit conditions allow siting of ambient monitors and development of a flare minimization plan, neither of which the public will have a chance to review and comment.

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[445] *See, e.g, In re Shell Gulf of Mexico, Inc.,* 15 E.A.D. 470, 510-514 (EAB 2020).

[446] Draft permit at 3.
[447] Draft permit at 32.
[448] Draft permit at 32-33.

Moreover, the permit fails to provide that the flare minimization plan be submitted to the Department for approval.

> 10.2 **Ambient Air Monitoring**. The Permittee shall establish ambient PM-10 and PM-2.5 monitoring during the construction phase as follows: a. At least 180 days prior to commencing construction, submit for Department approval a scaled site map(s) that identifies the proposed locations of one or more downwind PM-10 monitoring site and one or more downwind PM-2.5 monitoring site.4 Site the monitoring stations in areas that would likely experience the maximum construction-related 24-hour PM-10 and 24-hour PM-2.5 impacts from the Liquefaction plant project area. Include a written narrative that documents the reasons for selecting the proposed monitoring sites.[449]

> 17. **Vent Gas Disposal (Flares) BACT Emission Limits:** Limit the emissions from flares EUs 14 through 19 as specified in Table 7 and from EU 20 as specified in Table 8, which indicate that BACT control for these units is "*proper flare work practice requirements and establishing a flaring minimization plan*."[450]

VIII. The Permit Is Unlawful Because ADEC's Proposal Violated Public Participation and Federal Agency Consultation Requirements

A. ADEC Failed to Provide the Public Timely and Complete Access to the Supporting Record.

ADEC's failure to comply with the public notice obligations are so substantial that it precludes public participation. Moreover, the limited information provided by ADEC is so defective that it rippled throughout its proposal, hampering the public's participation and ability to review and identify issues. The harm from ADEC's procedural violation is that is has deprived the public's opportunity to have its views considered by ADEC. A key statutory objective of the Clean Air Act's PSD program is to "assure that any decision to permit increased air pollution … is made only after consideration of all the consequences of such a decision and after adequate procedural opportunities for informed public participation in the decisionmaking process."[451]

Consistent with EPA's regulations, to Alaska's PSD regulations require ADEC to – among other things:

> (i) Make a preliminary determination whether construction should be approved, approved with conditions, or disapproved.

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[449] Draft permit at 8-9.
[450] Draft permit at 23-24. (emphasis added)
[451] *In re Russel City Energy*, 14 E.A.D. 159, 175 (EAB 2008), citing In re *Rockgen Energy Center*, 8 E.A.D. 536, 557 (EAB 1999) (*quoting* CAA § 160(5), 42 U.S.C. § 7470(5)).

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(ii) Make available in at least one location in each region in which the proposed source would be constructed a copy of *all materials the applicant submitted*, a copy of the preliminary determination, and *a copy or summary of other materials*, if any, *considered in making the preliminary determination*.[452]

Contrary to the requirement to make available *all materials the applicant submitted* and *a copy or summary of other materials*, if any, *considered in making the preliminary determination*, ADEC did not initially and, despite herculean efforts by NPCA, failed to provide these materials. The following is a summary of the timeline of NPCA's communications with ADEC to obtain and review the information submitted by the applicant and the materials ADEC considered in making its proposed determination to approval AGDC's PSD permit request.[453]

9/23/2020	Letter from NPCA to ADEC requesting a 30-day extension to the deadline for comments (from October 11 to November 10)
9/25/2020	Letter from NPCA requesting complete permit application,[454] correspondence between ADEC and AGDC, including attachments listed in the permit application. ADEC's supporting analysis, including electronic files for the proposed permit (e.g., modeling files, emission calculation spreadsheets, etc.) All correspondence to and from the FLMs regarding the plant, including notes of meetings and conference calls.[455]
9/28/2020	Email from ADEC to NPCA indicating it will be granting the request to extend the comment period by 30 days.
9/28/2020	Email from ADEC to NPCA indicating it will need a public records request to move forward with the records requested on 9/25/2020.[456]
9/29/2020	ADEC notification of extension of public comment period to 11/20/2020, with attachments.
10/29/2020	Letter from NPCA to ADEC requesting the remainder of the foundational materials, including analyses and supporting information in native format.

[452] 8 AAC 50.040 adopts by reference 40 C.F.R. § 51.166(q)(2) (emphasis added).
[453] Copies of these communications are included as enclosures.
[454] The initial information provided redacted AGDC's assertions regarding confidential business information, which were subsequently withdrawn. Notably, ADEC did not resolve these unsubstantiated claims prior to public notice, and thus shifted the burden to the public to identify and request that the claims be lifted.
[455] Documents and emails between ADEC and external parties (permit applicant) and the FLMs/EPA/FERC, are not covered the deliberative process privilege since the incoming records are not ADEC's to protect, and for those that leave the agency, ADEC waives its right to protect. Therefore, it was unreasonable for ADEC to withhold these external communications, that it clearly "considered" in developing its proposed action. Further, we recognize some of these documents were initially covered by AGDC's CBI assertions, but those were subsequently waived after NPCA requested the AGDC BACT analysis.
[456] Despite the PSD regulations requiring that the permitting agency provide the information it considered, ADEC required that NPCA submit a formal record request, which created a barrier to public participation.

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10/29/2020	Email from NPCA, with addendum to NPCA's 10/29/2020 request, and confirmation from ADEC that it was received.
11/4/2020	Email and attached letter from ADEC to NPCA.[457, 458]
11/6/2020	Email and attached documents from ADEC to NPCA and others, 2nd extension of public notice, until December 10, 2020.
11/10/2020	Letter from NPCA to ADEC requesting records and providing information that demonstrated the requester met the requirements for waiver of fees.[459]
11/10/2020	Email from ADEC to NPCA providing notification that an email and link would arrive to download the monitoring and modeling files
11/12/2020	Response to NPCA's letter of 10/29/20, where ADEC explained that a fee waiver was needed. The individual responding has not yet seen NPCA's 11/10/2020 letter
11/16/2020	Although NPCA's representative had signed ADEC's certification form, as explained in this letter, ADEC informed her that was not adequate and that she needed to submit a subsequent signed document using the language "I hereby certify," which was done via this letter. The letter further responded to ADEC's request for clarification regarding a portions of the requested information.
11/20/2020	Email from NPCA to ADEC inquiring as to whether any additional information needed for the fee waiver. Response from ADEC that the request for fee waiver was passed along to the Commissioner for

[457] ADEC cover email explained that, "Requested Items 1 through 3:The Department has contacted the Alaska Gasline Development Corporation (AGDC) regarding your request and AGDC has since released all application materials previously submitted as confidential business information. The Department is currently working to get all of the application materials (requested items 1 and 3) as well as the Department's analyses in native MS Excel format (requested item 2) up on a new website. We will send you a link to this new webpage when it is live. The requested modeling files are too numerous and of too large a size to list on our webpage. Therefore, the Department will create a file transfer protocol (FTP) site for the requested modeling files and send you a link when it is live. Requested Items 4 and 5: The Department does not consider the consultation with the Federal Land Managers (FLMs) and communications with EPA to be a part of the material required for public notice. Therefore, please send the Department a Public Records Request for these materials and the Department will make a determination on whether this material will be released."

[458] ADEC further explained that "Regarding the additional 60-day extension of the comment period: The Department has not made a decision on the request to grant an additional 60-day extension. As of this email the preliminary permit has already been out for public comment for over 50 days. However, the Department recognizes that additional time to review the requested items is appropriate before the public comment period ends. Therefore, an extension of a yet undecided timeframe will be granted prior to the current public comment period's closing date of November 10, 2020. We will notify you when a determination is made."

[459] In addition to adding a requirement that the public submit a record request, ADEC insisted that NPCA pay fees for the information. While ADEC did not inform NPCA of the opportunity to submit a fee waiver request, NPCA's research identified this opportunity and submitted a fee waiver request.

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consideration and there are no additional clarifications needed by the Department regarding the request.

12/2/2020	Letter from ADEC to NPCA indicating that the fee waiver was denied,[460] this letter was transmitted at 1:05:01 AM MST.
12/2/2020	Email from ADEC to NPCA, transmitted at 1:20:09 AM, indicating that it was a request to "recall" the message sent earlier that morning.
12/3/2020	Letter from NPCA to ADEC including two requests, (1) copies of all electronic mail communications and attachments from the Federal Land Managers (FLMs) regarding the AK LNG Project as relates to the proposed PSD permit limited to time frame starting August 12, 2020 to present (December 3, 2020); and (2) extension of the public comment period until 1/11/2020 so that NPCA has time to review the communications from the FLMs.
12/4/2020	Email from ADEC to NPCA, which indicated the requested electronic communications from the Federal Land Mangers would be transmitted via a link to download the files.
12/10/2020	Email from ADEC to NPCA explaining that the Department further considered NPCA's request to extend the public comment period, which as explained in NPCA's letter of December 3, 2020, NPCA sought to allow meaningful review of the incoming communications from the FLM. Those records were made available via download link on Friday, December 4, 2020 at 5:45 pm EST. Therefore, while we appreciate the documents for review, it is disappointing we were given three business days to review them before comments are due.

ADEC's 74-day delay in providing the records documenting the PSD program's requirement that it first consult with the FLMs prior to proposing the permit, had the result of NPCA having only three business days to review an incomplete set of documents.[461] The absence of information available in the administrative record, which despite NPCA's efforts is still not available, prevented the public from being able to meaningfully understand and participate in the permitting process.

B. There is No Evidence to Show ADEC Provided the FLM's with the Required 60-day Comment Period

[460] ADEC's letter failed to explain how NPCA could appeal this decision. Furthermore, NPCA does not waive any rights to appeal ADEC's denial.

[461] NPCA first asked for the communications with the FLMs on September 25, 2020, and thus as seen in this timeline it was 74 days before a subset of the communications with the FLMs was provided.

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The Clean Air Act and regulations require that written notice of a permit application and proposed PSD permit be provided to the Federal Land Manager (FLM) for a Class I area that may be affected by emissions from the proposed Liquefaction plant.[462] ADEC's SIP regulations require that it

> [P]rovide written notice of any permit application for a proposed major stationary source or major modification, the emissions from which may affect a Class I area, to the Federal land manager and the Federal official charged with direct responsibility for management of any lands within any such area. Such notification shall include a copy of all information relevant to the permit application and shall be given within 30 days of receipt and at least 60 days prior to any public hearing on the application for a permit to construct. Such notification shall include an analysis of the proposed source's anticipated impacts on visibility in the Federal Class I area.[463]

State permitting agency requirements to consult with the Federal Land Managers regarding impacts to Class I areas are an important part of the PSD permitting regulations because the FLMs are "charged with direct responsibility for management of such lands have an affirmative responsibility to protect the air quality related values (including visibility) of such lands and to consider" in consultation with the permitting agency, "whether a proposed source or modification will have an adverse impact on such values."[464] ADEC's PreTAR explains that the Department initially "notified the FWS and the NPS of the pending PSD application on 12 October, 2017. The FWS responded the same day by saying they would like to kept informed and that they wanted to discuss the AQRV evaluation. The NPS expressed their interest during a 24 October, 2017 teleconference with the FLMs."[465] There is no other information in the PreTAR regarding ADEC's consultation with the FLMs. Furthermore, the PSD program requires that EPA consult with ADEC along with the FLMs regarding the FLM concerns. There is nothing in the record to show this occurred.[466]

In light of the special role and authority provided the FLMs and the lack of information about ADEC's consultation with the FLMs, as seen in the enclosures to these comments, NPCA requested information on the consultation for this proposed permit. As the enclosures show, NPCA tried over a period of months to obtain information on the communications that occurred between ADEC and the FLMs, and it was not until three business days before the comments were due that ADEC finally shared a portion of those records.

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[462] CAA § 165(d)(2)(A); 40 C.F.R. § 52.21(p) (Sources Impacting Federal Class I Areas)(2011).

[463] 8 AAC 50.040(h)(14) ADEC adopts by reference, 40 C.F.R. § 52.21(p). Moreover, "[i]rrespective of distance from a proposed source to the Class I area, permit applicants are legally obligated to demonstrate that their proposed facilities will not cause or contribute to air pollution in violation of any PSD increment, including the Class I increments. CAA § 165(a)(3)(A), 42 U.S.C. § 7475(a)(3)(A); 40 C.F.R. § 52.21(k)(2)." *NMU* at 329.

[464] *Id.*

[465] PreTAR at 3. The PreTAR includes citations to emails, but those emails were not included as part of the proposed permit action. (Email from James Renovatio (Department) to Andrea Stacy (NPS) and Catherine Collins (FWS), *Alaska LNG – Liquefaction Class I impacts for proposed PSD permitting*; 12 October, 2017; Email from Catherine Collins (FWS) to James Renovatio and Alan Schuler (Department), *Re: Alaska LNG – Liquefaction Class I impacts for proposed PSD permitting*; 12 October, 2017.) *Id.*

[466] Although several of the emails NPCA obtained through its records request to ADEC reveal that EPA was included in emails regarding the FLMs concerns about not receiving prior notice of the Liquefaction Plant, EPA was not involved in the subsequent communication emails between ADEC and FLMs where the proposed permit for the Liquefaction plant was discussed.

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Moreover, under the regulations, ADEC is required to "consider any analysis performed by the Federal land manager … that shows that a proposed new major stationary source … may have an adverse impact on visibility in any Federal Class I area." Additionally, where ADEC "finds that such an analysis does not demonstrate to the satisfaction of the … [ADEC] that an adverse impact on visibility will result in the Federal Class I area, the … [ADEC] must, in the notice of public hearing on the permit application, either explain his decision or give notice as to where the explanation can be obtained."[467] There is nothing in the information for the proposed permit to demonstrate that ADEC considered analysis from the FLMs, nor did ADEC's notice explain that it did not agree with the FLMs or give notice where ADEC's explanation can be obtained.

Additionally, ADEC's PSD regulations provide the following, and there is nothing in the proposed permit record to indicate whether ADEC received such a demonstration, or whether ADEC concurs:

> Federal Land Manager of any such lands may demonstrate to the … [ADEC] that the emissions from a proposed source or modification would have an adverse impact on the air quality-related values (including visibility) of those lands, notwithstanding that the change in air quality resulting from emissions from such source or modification would not cause or contribute to concentrations which would exceed the maximum allowable increases for a Class I area. If the … [ADEC] concurs with such demonstration, then he shall not issue the permit.[468]

The PSD regulations require that ADEC's public participation for the proposed permit action make available the following:

> [A] copy of all materials the applicant submitted, a copy of the preliminary determination, and a copy or summary of other materials, if any, considered in making the preliminary determination.[469]

The information regarding ADEC's notification to the FLMs regarding the permit application and proposed permit was not provided to the public as part of the proposed permit notice, nor was there a copy of materials that ADEC received from the FLMs. Therefore, in order to confirm the FLMs received the necessary notifications and review comments and materials sent by the FLMs to ADEC, as explained above, over a period of 74 days, NPCA submitted written requests, fee waiver documentation, certifications and clarification to ADEC to obtain this information.

ADEC provided the electronic communications from the FLMs to NPCA on December 7, 2020.[470] NPCA's review of the communications found that the FLMs had not been provided the notifications and opportunity to comment required by the PSD regulations. Instead, in addition to submitting significant concerns and details about the proposed permit, the FLMs expressed considerable concern about ADEC's timing and efforts.

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[467] *Id.*
[468] 40 C.F.R. § 52.21(p)(4).
[469] 40 C.F.R. § 51.166(q)(2)(ii).
[470] A compilation of these emails enclosed.

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C. There is No Evidence Demonstrating ADEC Provided Notice and Communicated with EPA

ADEC is also required to provide notice to EPA in its implementation of the PSD program. This notice consists of a copy of the permit application for sources subject to PSD and notice of every action related to the consideration of the permit.[471] ADEC's proposed permit information also failed to include this information. Therefore, NPCA requested information from the State regarding "[a]ll ADEC records regarding communication with EPA in its oversight role of this proposed permit,"[472] and despite the fact that the PSD regulations required this communication and that EPA generally provides comments on proposed PSD permits in its oversight role, as discussed above, NPCA was informed a written records request and agreement to pay fees were required before ADEC would release the communications. Thus, NPCA never received this information and was unable to determine whether the required notifications were provided and whether EPA expressed any concerns with either the permit application or ADEC's proposal to approve the permit.

CONCLUSION

In short, ADEC cannot validly finalize the proposed permit. To issue the permit as proposed would not only be unlawful under Alaska's SIP, but contrary to the Congressional purposes of the PSD program to:

- Protect health and welfare;
- Preserve and protect the air quality in Alaska's national parks and preserves, and national wilderness areas;
- Insure that economic growth will occur in a manner consistent with the preservation of existing clean air resources; and
- Assure that any decision to permit increased air pollution is made only after careful evaluation of all the consequences of such a decision.

Therefore, ADEC must either deny the request for construction and withdraw its proposed permit approval, or require AGDC submit a full and complete application addressing the myriad defects providing all required analysis and documentation. Should ADEQ repropose a valid permit, it must disclose all of the underlying information to the public.

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[471] These regulatory requirements are often memorialized between state permitting agencies and EPA regional offices in what's called a "Performance Partnership Agreement" ("PPA") that provides the details on communications like CAA permits.
[472] NPCA Letter to ADEC at 2 (Oct. 29, 2020).

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List of Enclosures

Comments Submitted on Behalf of
National Parks Conservation Association
Center for Biological Diversity
Northern Alaska Environmental Center

Preliminary Prevention of Significant Deterioration Permit No. AQ1539CPT01
Proposed in response to Application from Alaska Gasline Development Corporation to Construct a Liquefaction Plant in Nikiski, Alaska
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Name

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10.26.2020 ARD_AKLNG_LNG-LF__PG_turbines_Revised-vendor-TCI_revised-electricity-costs-inlet-temp.xlsm
10.26.2020 ARD_AKLNG_LNG-LF__PG_turbines_TCI_defualt_revised-electricity-costs-inlet-temp.xlsm
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-Appendix O: Biological Assessment, PDF.

-Appendix Q: Recreation Areas Affected by the Project, PDF.

-Appendix U: ANILCA Section 810 Final Evaluation, PDF.

-Appendix V: Health Impact Assessment, PDF.

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Exhibits 1-29 of Stamper Report:

Exhibit # to Stamper Report	Description
1	Fact Sheet for GE LMS100 Gas Turbine
2	Fact Sheet for GE 9E&GT13E2 Power Plants
3	Final Air Permit No. 1010524-001-AC (PSD-FL-444), Shady Hills Combined Cycle Facility
4	June 24, 2019 PSD Permit and Permit to Construct Balico LLC/Chickahominy Power, issued by Virginia Department of Environmental Quality
5	January 9, 2019, Registration Number 21599, Atlantic Coast Pipeline, LLC, issued by Virginia Department of Environmental Quality
6	NSR Permit No. 0761-M10, Williams Four Corners LLC, Thompson Compressor Station, Issued by New Mexico Environment Department
7	GE LM6000 Power Plants Fact Sheet
8	BASF NOxCat VNX SCR Fact Sheet
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12	Bay Area Air Quality Management District, Preliminary Determination of Compliance, Mariposa Energy Project, August 2010
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15	Permit No. R13-3271, issued July 21, 2016, for Marts Compressor Station
16	SCR Cost Calculation Spreadsheet for Alaska LNG Compressor Turbines at 2.0 ppm Controlled NOx Rate

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17	SCR Cost Calculation Spreadsheet for Alaska LNG Compressor Turbines at 3.5 ppm Controlled NOx Rate
18	SCR Cost Calculation Spreadsheet for Alaska LNG Power Turbines
19	Preliminary ADEC Technical Analysis Report for Construction Permit AQ0083CPT07 issued to Agrium U.S., Inc., for the Kenai Nitrogen Operations, November 20, 2020
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USFWS Air Quality Alaska Maritime National Wildlife Refuge (NWR) - Tuxedni Wilderness, available at https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/AirQuality.html

USFWS AQRVs Alaska Maritime National Wildlife Refuge (NWR) - Tuxedni Wilderness, available at https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/AQRV.html

USFWS Air Pollution Impacts (Visibility) Alaska Maritime National Wildlife Refuge (NWR) - Tuxedni Wilderness available at https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/Impacts.html

USFWS Air Pollution Impacts (Nitrogen & Sulfur) Alaska Maritime National Wildlife Refuge (NWR) - Tuxedni Wilderness available at https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/Impacts.html

USFWS Air Pollution Impacts (Ozone) Alaska Maritime National Wildlife Refuge (NWR) – Tuxedni Wilderness available at https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/Impacts.html

USFWS Monitoring Alaska Maritime National Wildlife Refuge (NWR) – Tuxedni Wilderness available at https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/Monitoring.html.

Williams, Megan. *Air Quality Review of the Alaska LNG Project Draft Environmental Impact Statement.* (September 30, 2019) PDF.

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Attachment B
NPS Comments

United States Department of the Interior
NATIONAL PARK SERVICE
Alaska Region
240 West 5th Avenue, Room 114
Anchorage, Alaska 99501

IN REPLY REFER TO:

Dave Jones
Environmental Engineering Assistant II
Alaska Department of Environmental Conservation
PO Box 111800
Juneau, AK 99811

Dear Mr. Jones:

The National Park Service (NPS) has reviewed Alaska Department of Environmental Conservation's (ADEC's) preliminary decision to approve Alaska Gasline Development Corporation's (AGDC's) application for Air Quality Control Construction Permit AQ1539CPT01. AGDC is proposing to construct a new natural gas liquefaction facility located near Nikiski, Alaska. In summary, we recommend that ADEC reconsider the control technology analysis for nitrogen oxide emissions from the turbines. Cost-effective, more efficient nitrogen oxide emission controls than those proposed for this facility are widely available and would address nitrogen deposition concerns in Denali National Park. Our detailed comments and analysis are provided below and in the attachments.

The liquefaction facility is one component of a much larger overall project and is the proposed terminus of an approximately 807-mile natural gas pipeline. The liquefaction facility will process an average of 2.7 billion standard cubic feet per day of feed gas. The liquefaction facility also includes a 20-acre offshore Marine Terminal where natural gas from Alaska's North Slope will be shipped to outside markets. The primary emission sources at the facility include ten natural gas-fired combustion turbines and seven flares.

Under the permitting provisions of the Clean Air Act, the NPS has evaluated potential visibility and other air quality related value (AQRV) impacts to Denali National Park (NP), a designated Class I area under the Act. While we determined that emissions from the facility would not cause significant visibility impacts in the park, we have concluded that those emissions would contribute to nitrogen deposition that may already be causing harm to park resources; in particular, to pollution-sensitive lichen species. Lichens are a critical component of Denali NP's plant communities, aiding in nutrient cycling in nutrient-poor systems and providing food, forage, and habitat for many species. Recently published research indicates that some lichen species could potentially decline by 50% of their natural cover at current estimated levels of background deposition. Based on modeling analyses, additional nitrogen deposition from the AK LNG liquefaction facility (as well as other AK LNG-related emissions) will potentially exacerbate these concerns. Implementing better nitrogen oxide (NOx) controls at the liquefaction facility would ameliorate the potential nitrogen deposition impacts of this proposal. (See Attachment A for our detailed analysis.)

One purpose of Denali NP is to "preserve extensive, unaltered natural ecosystems" within the park (Denali NP Foundation Statement, 2014). Currently, visitors to Denali NP can enjoy some of the cleanest air in the country. Continued preservation of these pristine ecosystems and the prevention of further deterioration for present and future generations is fundamental to the park's establishment as a unit of the National Park System. It is with this management direction in mind that we offer the following recommendations.

We recommend that ADEC reconsider the nitrogen oxide (NOx) Best Available Control Technology (BACT) determination for the ten combustion turbines located at the facility and implement Selective Catalytic Reduction (SCR) technology to reduce potential nitrogen deposition impacts in Denali NP. SCR is a commonly applied and cost-effective control technology for turbines and can reduce flue gas NOx concentrations to as low as 2.0 ppmvd. Requiring SCR at a 2.0 ppmvd NOx limit would ensure a level of NOx control at the liquefaction facility that is requisite with other similar sources in Alaska and elsewhere in the lower 48 states (see examples in Attachment B).

We also recommend that the draft permit be revised to include annual emission limitations for all criteria pollutants and that any best practices identified in the "flaring minimization plan" (which is to be completed prior to operation) are made enforceable by ADEC through the permit conditions. (See Attachment B and attached spreadsheets for our detailed BACT analyses.)

Finally, we encourage ADEC to continue ongoing discussions with us towards the goal of improving notification procedures for future permits. Supporting documentation for our nitrogen deposition impact assessment, our BACT evaluation and our authorities and obligations to comment on PSD permitting actions that may affect Class I areas is provided in the attachments.

Thank you for the opportunity to comment on this permitting action. We appreciate ADEC's willingness to work with us to address AQRV impact concerns in one of Alaska's iconic parks and the only Class I area administered by the NPS within the State of Alaska. We look forward to discussing the NOx BACT determination for this source and ongoing opportunities to resolve notification issues with respect to Class I analyses.

Please contact Paul Burger (907-644-3577) with the NPS Alaska Regional Office or Andrea Stacy (303-969-2816) with the NPS Air Resources Division if you have questions regarding the supplemental technical information.

Regards,

Grant Hilderbrand

Natural Resources Team Lead, Alaska Region
Acting for Deb Cooper, Associate Regional Director, Resources

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Cc: Deb Cooper, AKRO
Paul Burger, AKRO
Peter Christian, AKRO
Andrea Stacy, ARD
Carol McCoy, ARD

Attachments:
A: AQRV Impact Assessment—Nitrogen Deposition in Denali National Park
B: BACT Evaluation—SCR for the Combustion Turbines, Annual Emission Limits and Flares
C: NPS Authorities and Obligation to Comment on PSD Permits that May Affect Class I Areas

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ATTACHMENTS:

Attachment A: AQRV Impact Assessment—Nitrogen Deposition in Denali National Park

Attachment B: BACT Evaluation—SCR for the Combustion Turbines, Annual Emission Limits and Flares

Attachment C: NPS Authorities and Obligation to Comment on PSD Permits that May Affect Class I Areas

Attachment A:
AQRV Impact Assessment—Nitrogen Deposition in Denali National Park (NP)

Introduction

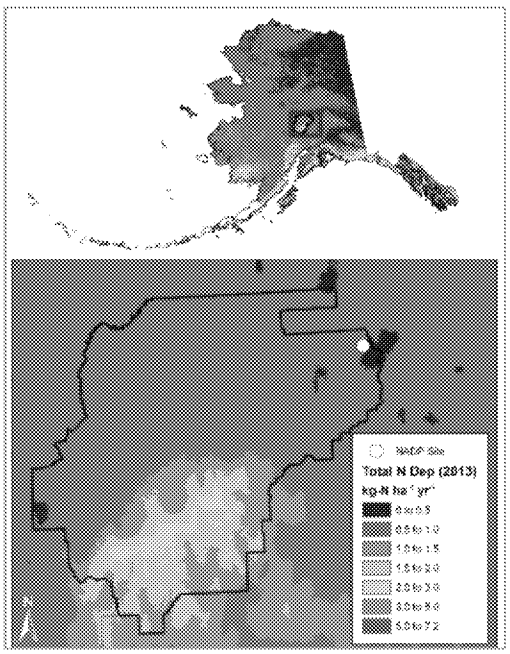
Current estimated levels of nitrogen pollutant deposition (1.0 – 2.0 kg/ha/yr) in the southern end of the park are potentially causing declines in sensitive lichen communities. The additional nitrogen deposition from the AK LNG Liquefaction facility (as well as other AK LNG-related emissions) could exacerbate these concerns.

Modeling performed by both the applicant and the Federal Land Management Agencies (FLMs) demonstrates that nitrogen oxide (NOx) emissions from the facility alone (and in conjunction with other AK LNG emission sources) results in additional nitrogen deposition above NPS ARD significance thresholds.[1] The modeled deposition impacts from the AK LNG sources are most significant in the southern end of the park, which overlaps with the geographic extent of the areas that already receive the highest estimated deposition inputs and are potentially impacted by current deposition. The AK LNG sources will result in increased nitrogen deposition in the most vulnerable areas of the park.

Estimates of Current Total Nitrogen Deposition in Denali NP

Hember et al. (2018) developed a model for total nitrogen (N) deposition for 2013 that shows a range within the park from 0.5 to 2.1 kg-N/ha/yr (median 0.8 kg-N/ha/yr), with the highest deposition occurring in the southern regions of the park.

Figure A-1: Estimated Background Nitrogen Deposition in Denali NP.



[1] The FLAG 2010 guidance defines the DAT as "… *the additional amount of nitrogen or sulfur deposition within an FLM area, below which estimated impacts from a proposed new or modified source are considered negligible. In other words, if the new or modified source has a predicted nitrogen or sulfur deposition impact below the respective DAT, the NPS and FWS will consider that impact to be negligible, and no further analysis would be required for that pollutant. In cases where a source's impact equals or exceeds the DAT, the NPS/FWS will make a project-specific assessment of whether the projected increase in deposition would likely result in an "adverse impact" on resources considering existing AQRV conditions, the magnitude of the expected increase, and other factors.*" This Attachment summarizes the existing AQRV conditions for Denali NP as part of the project-specific assessment.

Nitrogen Deposition—Risk to Lichen Communities in Denali NP

Lichens are a critical component of Denali NP's ecosystems, aiding in nutrient cycling in nutrient-poor systems and providing food, forage and habitat for many species (Stehn et al. 2015). There are 431 unique lichen species known to occur within Denali NP and lichens are found in many habitats throughout the park, often covering a large proportion of the landscape. A complex web of interactions connects members of the ecosystem, and consequently, lichens significantly affect the ecosystems in which they live, serving important roles in park ecosystem functioning.

Lichens lack root structures and instead "filter" moisture and nutrients from the air. Because of this, lichen species are often sensitive to air pollution but vary in sensitivity among species—an understanding of the specific species present as well as their known tolerance for air pollution is an important consideration when determining the potential effects of pollutant deposition. One tool that can assist managers in addressing species or ecosystem response to air pollution is called a critical load.

Critical loads are scientifically defined thresholds designed to aid land managers in identifying the level of deposition below which harmful impacts to ecosystems, ecosystem components or individual species do not occur (Porter et al. 2005). When deposition exceeds a critical load threshold the integrity of the ecosystem begins to decline. Critical load values have been identified for cyanolichen communities, as well as for 42 individual lichen species documented to occur within Denali NP.

Lichen Community Response Curves: Geiser et al. (2019) developed a community response curve for cyanolichen communities. Cyanolichens are important because they provide habitat and nutrient-rich food for mollusks and other invertebrates and help balance N cycling in the forest (Geiser et al. 2019). A 20% decline in cyanolichen communities occurs at deposition levels above 1.3 kg nitrogen/ha/yr and a 30% decline in cyanolichen communities occurs at deposition levels above 1.9 kg-N/ha/yr,[2] indicating that cyanolichen communities in the southern end of the park may already be experiencing declines due to current deposition.

Individual Species Response: There are 431 known lichen species within Denali NP, and 97 of these species have a calculated critical load of N for a reduction in abundance (Stehn et al. 2015, Geiser et al in prep.). Of the 97, there are 42 lichen species within Denali NP that have a nitrogen critical load for a 20% decline in detectability between 1.0 and 1.6 kg-N/ha/yr. Thirty-four of these species are expected to decline by up to 50% within a range of 1.3 to 1.9 kg-N/ha/yr. Of the 42 species in Denali NP with identified critical load values, 33% are cyanolichens, 14% are forage lichens and 52% are matrix lichens. The median critical load value for the individual Denali NP cyanolichen species is the same nitrogen deposition load (1.3 kg-N/ha/yr) as the critical load to protect cyanolichen communities already published.

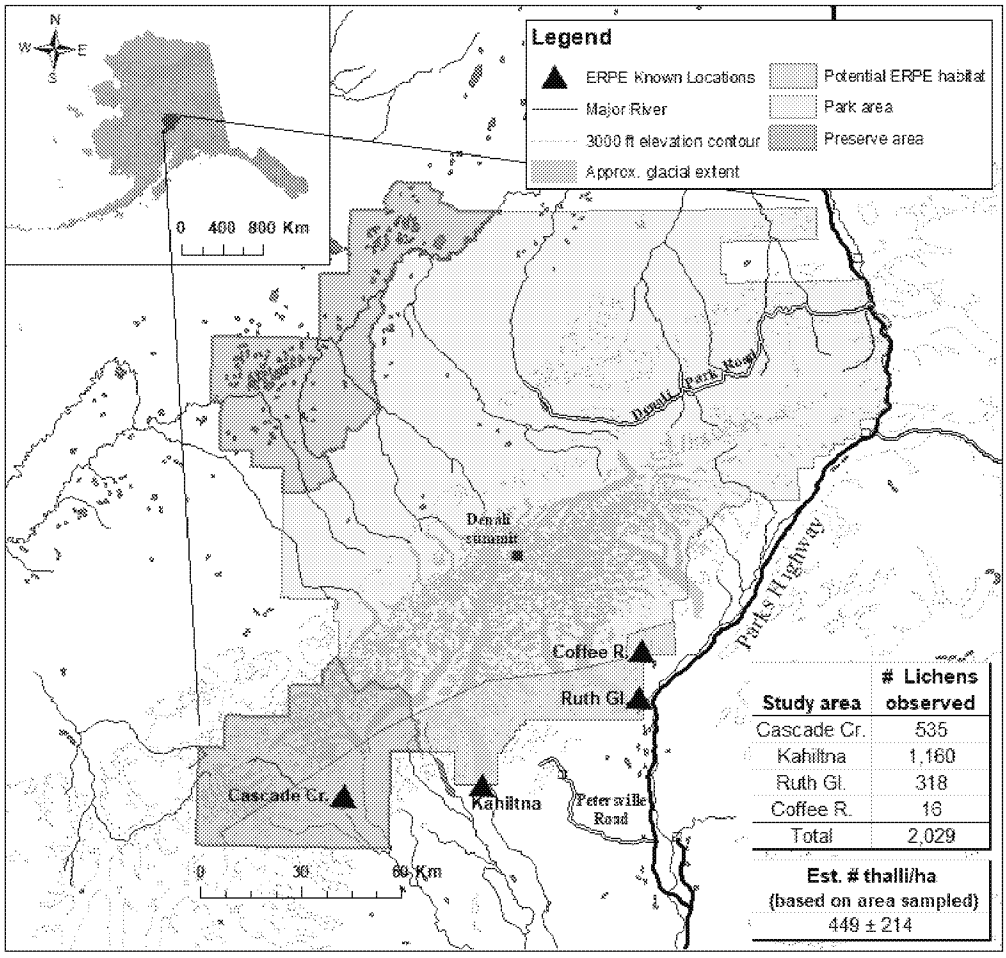
Boreal felt lichen—an IUCN Critically Endangered Lichen: Of concern within the cyanolichen communities is the globally rare boreal felt lichen (*Erioderma pedicellatum*), which has only recently been discovered in the U.S. at sites within Denali NP. The species is listed as critically endangered by the International Union for Conservation of Nature (IUCN). Given the species rarity, the boreal felt lichen was not directly assessed in the studies referenced above but is known to co-occur with sensitive cyanolichen species that are potentially in decline.

Individual lichens in the Denali population live primarily on the twigs of spruce trees and achieve most of their nutrient needs through absorption of moist air or receipt of water-borne nutrients flowing or dripping through the tree canopy (Stehn et al. 2013). Nutrients are passively absorbed through their thalli, or body surface, increasing their potential susceptibility to pollutant deposition. Regional air pollution has been linked to declines in *Erioderma pedicellatum* in Atlantic Canada (Maass & Yetman 2002) and Norway

[2] Boot-strapped 95% confidence interval on this CL, 0.49 – 1.3 kg N, meaning that 1.3 kg/ha/yr is at the high end of the range for this CL.

(Goudie et al. 2011). Known locations of *Erioderma pedicellatum* are in the southern portion of Denali NP, which coincide with areas estimated to receive the highest levels of current nitrogen deposition and the areas most impacted by the AK LNG facility.

Figure A-2: Known Locations of the Boreal Felt Lichen (Erioderma pedicellatum) in Denali NP (from Stehn et al. 2013)



Modeled Nitrogen Deposition from AK LNG Source

We re-ran the modeling analysis with four emission scenarios.[3] The results for each scenario are provided in Table A-1 below. All modeled emission scenarios exceed the NPS nitrogen deposition analysis threshold (DAT); however, the magnitude and geographic extent of the DAT exceedances change based on the modeled emission scenario. We note that on an annual basis, the facility-wide potential to emit is considerable when the annual flare emissions are accounted for (up to 5,040 TPY NOx). Because the deposition analysis evaluates an annual flux in deposition (kilograms per hectare per year), the FLM analysis also considered annual potential to emit from the flares (accounting for the annual limitations of 500 hours per year for the wet and dry flares and 144 hours per year for the low pressure flare). Additionally, the FLM agency modeling analysis considered the emissions from the liquefaction facility alone as well as in conjunction with the mainline compressor and heater stations associated with the much larger AK LNG project. The additional emissions from the compressor stations

[3] Air resources staff in the FLM agencies—including the Fish and Wildlife Service and NPS air resources staff.

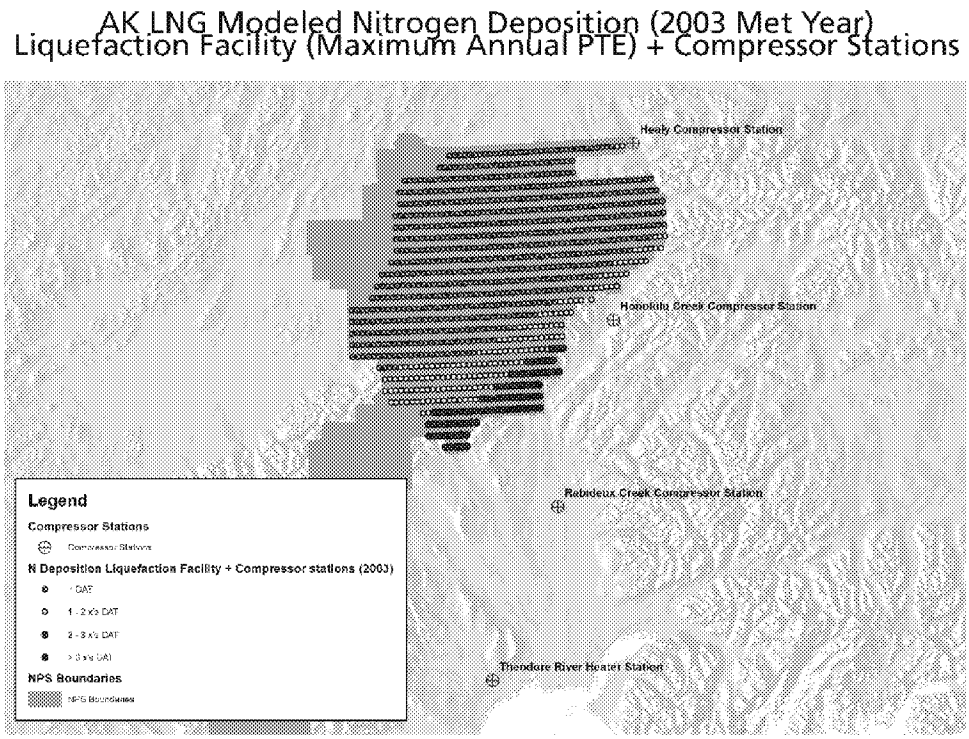
were considered in the analysis under the additional impacts analysis provisions of 40 C.F.R 52.21.[4] These provisions call for an impact analysis that considers other industrial source growth associated with the facility.

Table A-1: FLM Deposition Modeling Results for the AK LNG Liquefaction Facility

Model Year	Modeling Scenario	Max N Dep (kg/ha/yr)	DAT Exceedance (X's over DAT)
2003	Liquefaction Facility Only - LFF Normal Ops	0.0079	1.58
2003	Liquefaction Facility + Compressor Stations - LFF Normal Ops	0.0131	2.62
2003	Liquefaction Facility Only - LFF Max Annual PTE	0.0134	2.68
2003	Liquefaction Facility + Compressor Stations - LFF Max Annual PTE	0.0185	3.7

As noted previously, the geographic extent of the modeled nitrogen deposition from the AK LNG facility occurs in the southern and southeastern end of Denali NP, which also coincides with the areas estimated to receive the highest amounts of current cumulative deposition. (See Figures A-3 through A-5)

Figure A-3: Modeled Nitrogen Deposition for the AK LNG Liquefaction Facility (Flares Maximum Annual PTE) plus the AK LNG Mainline Compressor and Heater Stations



[4] 40 CFR 52.21 (o) *Additional impact analyses.* (1) The owner or operator ***shall 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***.

Figure A-4: Modeled Nitrogen Deposition for the AK LNG Liquefaction Facility Alone (Flares Maximum Annual PTE)

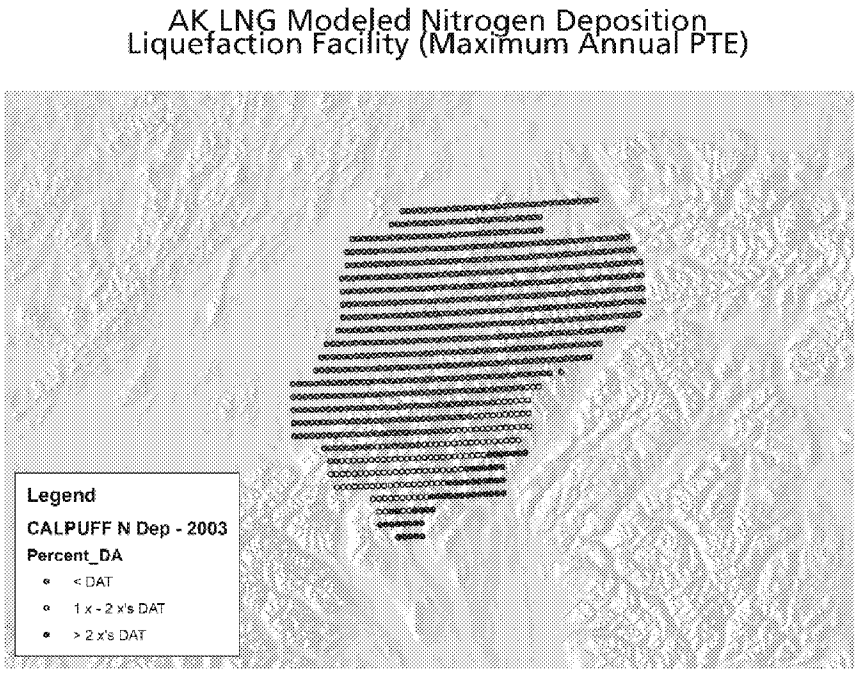
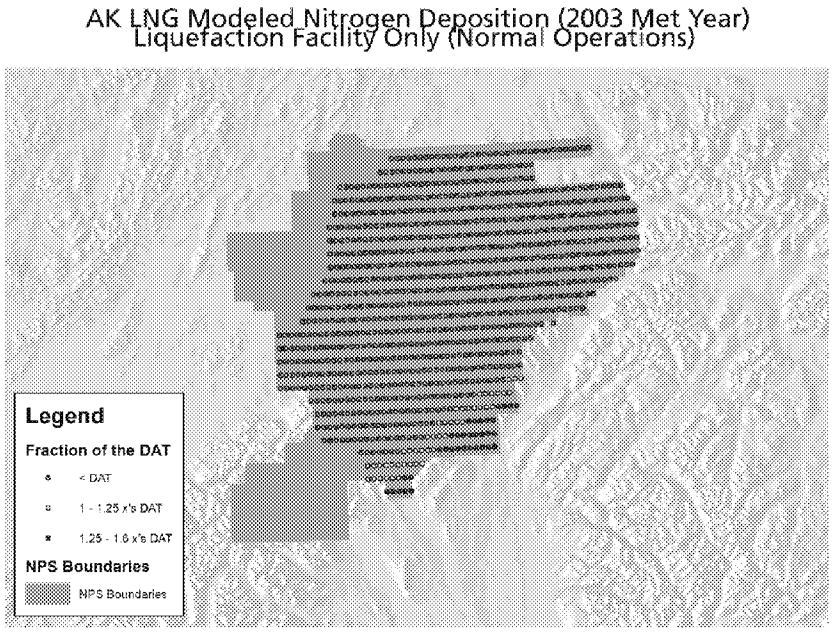


Figure A-5: Modeled Nitrogen Deposition for the AK LNG Liquefaction Facility Alone (Flares in Pilot Purge Mode Only—No Flaring Events)



Additional Impacts Analysis

AGDC provided an additional impacts analysis in their March 2018 Project Information Form Attachment 10. The "Additional Impacts Analysis" is required under 40 CFR 52.21(o). Several of the conclusions reached in that report contradict the information provided in our comments—we would like to address these.

First, in their growth analysis required under 40 CFR 52.21(o)(2), the applicant concludes: "*No industrial or commercial growth is likely to occur as the requirements for the project are expected to fit within the current infrastructure in the area.*" We note that there are several proposed compressor and/or heater stations to be located along the pipeline delivering natural gas to the liquefaction facility, three of which are in proximity to Denali NP, the only NPS Class I area in Alaska (see map above). This source growth is clearly connected with the liquefaction facility, as it is part of the overall AK LNG project, and therefore, it is relevant to the Class I impacts analysis. For this reason, our revised modeling analysis also considered the compressor and heater stations and we recommend that AGDC's analysis should as well.

Second, the vegetation impacts analysis required under 40 CFR 52.21(o)(1) concluded: "*Therefore, a project that demonstrates compliance with the NAAQS easily demonstrates compliance with USEPA's threshold screening values and indicates the project will not cause deleterious effects to vegetation.*" The analysis went on to acknowledge however that "*lichen species are particularly sensitive to sulfur dioxide (SO2)*" and utilized a 1989 U.S. Forest Service document to consider impacts to lichens in the Tongass National Forest and concluded the "*ambient air quality impacts are overstated and they are still not expected to result in adverse growth effects or tissue injury to vegetation in the project area.*" Based on the information provided above, AGDC's information is outdated, does not consider the potential deleterious effects of nitrogen deposition on lichens, and inaccurately concludes that the NAAQS are protective of sensitive vegetation species. As we note above, lichens in Denali NP may be negatively impacted by nitrogen deposition and the AK LNG project may exacerbate these concerns.

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Attachment B:

BACT Evaluation of SCR for the Combustion Turbines, Annual Emission Limits and Flares

Combustion Turbines NOx BACT— Introduction

The AK LNG applicant (AGDC) concluded that Selective Catalytic Reduction (SCR) technology is not economically feasible for the four power generation turbines and six compressor turbines at the liquefaction facility. The Alaska Department of Environmental Conservation (ADEC) proposes to approve this conclusion. We have evaluated the technical accuracy of the BACT analysis and conclusions and found several deficiencies in the applicant's BACT evaluation. When corrected, SCR is much more cost effective for the AK LNG liquefaction facility turbines than estimated by AGDC. Furthermore, AGDC's own estimates are well within BACT cost-effective thresholds set by other states. (A summary of our analysis revisions and results are provided below.) **We recommend that ADEC reconsider the AK LNG NOx BACT determination for the combustion turbines in light of the information presented in this technical attachment, as well as the information regarding nitrogen deposition impacts presented in Attachment A. This recommendation is based on the following three premises:**

1. Other sources in Alaska have either proposed or installed SCR as NOx BACT for similar combustion turbines, including the Agrium plant, which is an existing fertilizer manufacturing facility located adjacent to the proposed liquefaction facility site. It can be inferred that these sources find SCR to be an economically feasible option, even in Alaska where costs are generally higher. AGDC has not adequately demonstrated why similar costs are not feasible for the liquefaction facility.
2. The cost effectiveness estimates provided by ADEC and AGDC are within the range of BACT cost effectiveness thresholds determined to be acceptable in other states, including determinations that require SCR on combustion turbines. Furthermore, given the fact that costs are generally higher in Alaska relative to the rest of the U.S., it would be reasonable to conclude that BACT cost effectiveness thresholds should be somewhat higher in Alaska as well, or at a minimum on par with other regions of the U.S. Setting an unreasonably low threshold in an inherently high cost area essentially eliminates the application of BACT throughout the region, as most technologies could be found economically infeasible, even when such technologies are widely available.
3. Our revisions to the cost analysis indicate SCR may be more cost effective than estimated by AGDC.

Combustion Turbines NOx BACT— AK LNG versus Agrium Inc.

AK LNG's industrial neighbor, the Agrium fertilizer plant, is also in the process of obtaining a PSD permit to restart its facility. Despite the fact that these facilities are on similar permitting timeframes, are located adjacent to one another and each propose to install new combustion turbines, there is a significant discrepancy in the NOx BACT determinations between these sources.[5] Agrium U.S. Inc. proposes to install SCR as BACT for their five 55.4 MMBtu/hr Solar Turbines.[6] However, AGDC has concluded that the same technology is not economically feasible for the four 430 MMBtu/hr power generation turbines

[5] A fundamental precept of BACT is that similar emission units in similar situations should have similar emission limits, unless it is demonstrated that there are significant differences; that demonstration has not been made.

[6] While we agree with the determination that SCR is BACT, we continue to recommend that lower NOx emission limits are achievable for the Agrium emission units, as evidenced by the vendor quote obtained by AK LNG for their turbines.

and six 1164 MMBtu/hr[7] compressor turbines at the liquefaction facility. Based on the TARs, ADEC proposes to approve each of these determinations.

We note that the Agrium Solar turbines are much smaller units than those proposed for the AK LNG liquefaction facility. In general, the "economy of scale" concept indicates that the smaller the unit, the lower the potential emissions reduction and the less cost-effective a measure becomes on a $/ton basis. While we do not have a cost evaluation for SCR on the Agrium turbines (a cost analysis is not required if a top-level control is selected), it is likely more expensive per ton of NOx removed to control the Agrium turbines than to control the AK LNG liquefaction facility turbines, calling AGDC's economic feasibility determination into question.

Combustion Turbines NOx BACT—Cost Thresholds Set by Other States

Notwithstanding the lower cost effectiveness estimates we provide below, we note that the cost estimates provided by ADEC and AGDC in their most recent November 5, 2020 revisions to their cost estimates are well within the range of BACT cost effectiveness thresholds used by other states:

- Pennsylvania: In their 2018 Technical Support Document for Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations, PA set a $10,000/ton cost effectiveness threshold for SCR on turbines and reciprocating internal combustion engines. This document concluded that "SCR is BAT for turbines greater than or equal to 15,900 bhp" (BAT is Best Available Technology). Accordingly, the PA Department of Environmental Protection (DEP) established a General Permit NOx limit of 2.0 ppmvd for turbines equipped with SCR[8] in the 15,900 HP or greater size class and noted that stack tests demonstrate NOx emissions from turbines in this size range equipped with SCR are capable of achieving emissions in the range of 1.6 to 1.8 ppmvd. The turbines located at the AK LNG facility are significantly larger than 15,900 HP and well within the size range determined by PA DEP to be cost effective for SCR. We also note that PA DEP's general permit rule applies to turbines utilized in load-following applications including natural gas compression turbines at compressor stations and gas processing plants and are similar to the turbines at the liquefaction facility.
- Texas: In their recently released draft Regional Haze SIP, Texas identified a $10,000/ton threshold for BACT determinations. "For the upper-end of the cost thresholds, $10,000 per ton of NOX and of SO2 emissions reduced was considered because this threshold may be used for permitting new, modified, and reconstructed sources of air pollutants under the New Source Review (NSR) air permitting program."
- Colorado RACT: CDPHE has utilized a $12,000-$19,000/ton cost threshold in several recent RACT determinations (CDPHE, personal communications, 2020).
- New Mexico: Recent permit applications submitted to the NM Environment Department for combustion turbines at oil and gas sources reflect a proposed NOx BACT limit of 2.0 ppmvd with SCR, including the XTO Husky Central Delivery Point.
- Reasonable Progress Analyses: Finally, we have begun reviewing reasonable progress four factor cost analyses prepared for sources throughout the country. Not all states have set cost thresholds for the second round of Regional Haze planning, but we have seen several states propose or recommend cost thresholds in the range of $5,000 up to $10,000 per ton for *retrofits*. Retrofit thresholds set by states are usually lower than thresholds established for new or modified sources, as retrofits are generally imposed upon a source that is not otherwise undergoing any proposed

[7] Note the heat input values reported for the LF facility turbines reflect rated capacity and therefore do not match those reported in the pre-permit and pre-TAR, which reflect "the rating for each unit at the yearly average ambient temperature for the Liquefaction Plant of 40°F." Our analysis reflects the rated capacity as reported by the applicant and used in the applicant's BACT analysis.

[8] PA DEP established a dual BAT limit for turbines in this size class with "emission limits of 9.00 ppmvd for NOX uncontrolled and 2.0 ppmvd for NOX through use of SCR."

physical operational change. Yet, in many of these states, retrofit thresholds appear to be higher than what AGDC would consider cost effective for a greenfield source.

Combustion Turbines NOx BACT— Results

We summarize our estimates below, along with AGDC and ADEC reported results. (Note: The AGDC reported values are the revised results provided in the summary table in a 11/9/2020 email from Lisa Haas with AGDC to Dave Jones with ADEC.) Documentation of our various analysis assumptions are provided in the following sections.

- Liquefaction Facility Power Generation Turbines:
  - Our initial results – **$5,873/ton** to **$6,041/ton** NOx removed (2019$) using TCI based on EPA default method in the CCM, 7th edition and TCI based on revised vendor quote calculations
  - Our revised results—**$7,840/ton** NOx removed (2019$) using TCI based on revised vendor quote calculations and AGDC 11/5/2020 revised electricity costs.
  - AGDC result: $10,759/ton NOx removed (2017$)
  - ADEC result: $9,878/ton NOx removed

- Liquefaction Facility Compression Turbines:
  - Our initial results – **$4,319/ton** to **$4,987/ton** NOx removed (2019$) for TCI based on EPA default method in the CCM, 7th edition for an SCR inlet temperature of 730° F and 970° F, respectively, and **$4,383/ton** to **$5,051/ton** NOx removed (2019$) for TCI based on revised vendor quote calculations and an SCR inlet temperature of 730° F and 970° F, respectively.
  - Our revised results—**$6,237/ton** NOx removed (2019$) using TCI based on revised vendor quote calculations and AGDC 11/5/2020 revised electricity costs.
  - AGDC result: $10,506/ton NOx removed (2017$)
  - ADEC result: $10,519/ton NOx removed

As noted above, the revised cost estimates, including some of ADEC's own revised estimates, are within the range of cost-effective thresholds established by other states for BACT determinations (and, in some cases, analysis of retrofits).

Combustion Turbines NOx BACT—Documentation of Our Technical Evaluation:

We completed our cost analyses using the EPA Control Cost Manual (CCM) Section 4, Chapter 2 – SCR 7th edition. Two scenarios were used to estimate the Total Capital Investment (TCI) in our estimates. The first scenario used the appropriate EPA default TCI equation provided in the 7th edition CCM.
The second scenario used the vendor quotes provided in Appendix C.1, AeriNOx SCR Quote (January 2020) of AGDC's BACT Information Request Response, along with adjustments to the applicant's TCI calculations (CCM 6th edition) to override the estimates in the EPA 7th edition method TCI calculations. AGDC contends that their 6th edition CCM estimates "are likely more accurate for the Alaska LNG Project than the 7th edition results, because the 7th edition has limited capability for the user to enter site specific information. Site-specific conditions for both the GTP and the Liquefaction Facility are significantly different from the 'standard' EPA model because of the increased transportation requirements to get equipment to Alaska and the operating conditions."[9] We reviewed the applicant's TCI calculations under their CCM 6th edition analysis. While we agree that vendor quotes are likely more reliable than study-level estimates, AGDC added many non-site-specific construction costs using "CCM defaults" to their vendor quote information. We found that the applicant was likely double counting some TCI fees by including CCM default calculations for line items that were also included in the vendor

[9] While it is likely that the cost of transporting equipment into the interior of Alaska is relatively high, both the Agrium and the AGDC LF facilities are located immediately on the Cook Inlet with easy access to shipping.

quote. Several fees appeared to be unreasonably escalated without adequate documentation. We revised the TCI estimates using the vendor quotes accordingly. Our revisions to the applicant's TCI calculations are documented in the spreadsheets for each type of turbine in the "Vendor_TCI_Estimate-revised" tabs. ***It is worth noting that the results of our revised TCI estimates based on the vendor quotes are roughly equivalent to the EPA default method for calculating TCI in the 7th edition CCM.***

Summary of Other Analysis Changes:

- **Interest Rate** – The applicant used a 7% and 5.5% interest rate in their Control Cost Manual 6th edition analysis and Control Cost Manual 7th edition analysis, respectively. In our analysis, we reduced the interest rate to 3.25% (The ADEC analysis also used the bank prime rate).

  - Basis for change: Section 1 – Introduction to the EPA Control Cost Manual (CCM) recommends the use of the current bank prime rate, which has been at 3.25% for the past seven months with little likelihood of changing in the near future.

- **Reagent Costs** – In our analysis we reduced the ammonia costs from $2.24/gal for 19% aq. to $0.167/gal for 19% aq. (The CCM default for a 29% ammonia solution is $0.293/gallon.)

  - Basis for change: AGDC's 12/3/2019 BACT information request response on pdf page four in the "LNG Assumptions" section states "Ammonia cost based on $0.30/pound (Weekly Fertilizer Review, 4/2015)." We point out several flaws in this assumption:

    First, it appears that this assumption is *not* based on a vendor quote. Instead, AGDC is relying on outdated publicly available (although difficult to find) commodity pricing provided by an online agriculture industry magazine. If you compare AGDC's $0.30/pound ($600/ton) 2015$ estimates for ammonia to the USGS commodity pricing source cited in the 7th edition SCR CCM chapter, costs are roughly similar, with USGS reporting average annual ammonia costs in the $470-$530/ton range in the 2014-2015 timeframe. As such, these commodity pricing estimates are outdated. Furthermore, the 2015 "Brenntag quote" cited by AGDC in their "GTP Assumptions" and provided in Appendix C.2 appears to be a cost calculation sheet provided by a consultant (URS) as opposed to an actual vendor price quote and is specific to the GTP, not the liquefaction facility.

    Our liquefaction facility analysis updated the ammonia commodity pricing to reflect the 2019 cost year used in our analysis ($230/ton). We relied upon the USGS source cited in the 7th edition SCR CCM chapter,[10] as it appeared this was no less applicable than Fertilizer Weekly review and because AGDC did not provide a reference or link for their estimates. Therefore, we could not replicate or find this information in the Weekly Fertilizer Review source cited.

    Second, it appears that the applicant did not correctly convert from $/lb (or $/ton) pure NH3 costs to $/gal because they did not account for the solution concentration in the conversions, which significantly inflates the $/gal costs of the reagent, as provided for in the EPA 7th edition SCR CCM chapter. This is based on information provided in Appendix C.2, as well as on page 4 of the January 10, 2020 BACT Cost Effectiveness information request response. For instance, on page 4, the applicant notes that reagent costs for the LNG facility (CCM 6th edition inputs) are $0.30 per pound or $600/ton of pure NH3 (2015 cost year – again, this value is roughly two and a half times higher than the recent national average of $230/ton for

[10] https://www.usgs.gov/centers/nmic/nitrogen-statistics-and-information

2019).[11] Following the methodology in EPA's revised 2019 CCM SCR Chapter, the $0.30 per pound cost would convert to $0.437/gal after accounting for 19% solution (See Figure 1 below and rows 51-80 in the INPUTs_Conversions_Data_Sources tab in the attached spreadsheets for EPA's conversion calculations).

- **Cost Year:** We changed the cost year from 2017 to 2019 using CEPCI. This would have the effect of increasing the costs relative to AGDC's.

- **Electricity Costs** - We performed several analyses with a range of estimated electricity costs ($0.0244/kWh to $0.103/kWh), as compared with the applicant's estimate of $0.127 to $0.16/kWh.[12]
    - Basis for change: The AK LNG liquefaction facility will generate power onsite with the four power turbines firing pipeline natural gas.

      AGDC will not pay utility power usage fees. We recognize that despite this, there will likely be electricity costs incurred by the applicant due to natural gas usage that would otherwise be a salable product, as well as operating and maintenance costs associated with the power generation turbines. In initial reviews, we attempted to account for this using EIA spot prices for fuel (EIA, $2.56/MMBtu)[13] and natural gas usage in the power turbines generating onsite power. Based on our initial input, AGDC revised their electricity costs at the request of ADEC. We note that AGDC has not provided rigorous justification for their revised cost estimates. Nonetheless, we revised our analysis to use the low end of AGDC's estimates for electricity costs at $0.103/kWh. We used the lower end of the range because this is more in line with electricity cost estimates used in the Agrium BACT analysis.[14] The Agrium application used an electricity cost estimate of $0.101/kWh. Like AGDC, the Agrium facility will operate combustion turbines for on-site power production—the Agrium pre-tar states "electrical power comes from gas turbine generators and by purchase from a local utility." However, unlike the AK LNG facility, Agrium will be required to purchase natural gas and some fraction of their electrical needs from an outside supplier. Yet, Agrium's estimated electrical costs are lower than AGDC's low-end estimates. AGDC has not provided addition documentation to verify these estimates. Accordingly, we used the low end of AGDC's estimates.

- **SCR Inlet Temperature:** We revised the SCR inlet temperature for both the power turbines and the compressor turbines.
    - Basis for the assumption:
        - Power Turbines: The applicant used an SCR inlet temp of 314° F. However, we note that the PG turbines are operated in combined cycle mode. The inlet temp assumed by the applicant is the same as the stack exit temperature used in the modeling analysis and likely represents the stack exit temperature following the Heat Recovery Steam Generator (HRSG). Generally, in a combined cycle

[11] The AGDC analysis did not provide an actual vendor quote, but assumed an NH3 cost that is roughly two and a half times higher than the national average. USGS commodity pricing summaries reflect an average NH3 cost of $230/ton in 2019. We note that (1) the liquefaction facility is located adjacent to a fertilizer processing plant, a potential local source of NH3 that intends to restart in the near future, and (2) if NH3 cannot be obtained locally, the facility has a co-located shipping port. Either way, the ARD analysis assumed a $/ton commodity price equivalent to the national average for 2019.

[12] In a November 5, 2011 memorandum, AGDC revised their electricity costs in response to staff level input from the NPS.

[13] Reported value from EIA, and represents the average of the daily closing spot prices for natural gas at the Henry Hub in Louisiana. Spot prices were used rather than industrial consumer prices, as the fuel utilized at the source is a salable product. https://www.eia.gov/naturalgas/monthly/pdf/table_03.pdf

[14] See the electricity cost estimates in the Agrium BACT VOC and CO control costs analyses.

configuration, the SCR is placed between the turbine and the HRSG, and thus the SCR inlet temperature would be ideal for SCR operating efficiency (roughly 730° F).

- Compressor Turbines: The applicant assumed an SCR inlet temp of 970° F. The analysis was run with the applicant's inlet temperature assumption as well as a revised inlet temperature of 730° F to reflect either the addition of tempering air or the use of high-temperature catalyst (which is not accounted for in the workbook). Results are similar and are reported below.

- **Controlled and Uncontrolled Emission Rates**: We assumed the same uncontrolled and controlled emission rates as the applicant.
  - Basis for the assumption: The applicant assumed a controlled NOx rate for all turbines of 2.0 ppmvd @ 15% O_2 based on a vendor quote provided in Appendix C.1 to the January 10, 2020 BACT Cost Effectiveness information request response. We used the same emission rate because it is based on a vendor guarantee. For the uncontrolled emission rate, we note that AGDC has not identified the specific type of turbine to be constructed. Therefore, pre-control emissions could be higher than the 15 ppmvd assumed by AGDC (up to 25 ppmvd). Nonetheless, our analysis assumed the 15 ppmvd uncontrolled rate. If the turbine ultimately selected has a higher uncontrolled rate of 25 ppmvd, it would result in a higher control efficiency (92%) and a lower cost effectiveness estimate.

Examples of reagent cost calculations using calculation methods presented in the 7th edition EPA CCM chapter on SCR (see spreadsheets for additional detail):

Figure B-1: AGDC Reagent Cost Assumptions & Calculation Corrections for the LNG Facility.

Conversions for NH3 Reagent Costs (if given NH3 costs in $/ton using USGS source referenced in CCM**)

99.5 % Anhydrous conversion from pure NH3:	
600	$/ton pure NH3
0.3	$/lb pure NH3
11.45	$/ft3 (Anhydrous) density
1.53	$/gal NH3
1.52	$/gal 99.5% NH3 solution

29.4% Aqueous conversion from pure NH3:	
600	$/ton pure NH3
0.3	$/lb pure NH3
16.83	$/ft3 (29% Aqueous) density
2.25	$/gal NH3
0.662	$/gal 29% NH3 solution

19% Aqueous conversion from pure NH3:	
600	$/ton pure NH3
0.3	$/lb pure NH3
17.19	$/ft3 (19% Aqueous) density
2.30	$/gal NH3
0.437	$/gal 19% NH3 solution

50% Urea Conversion	
600	$/ton Urea
0.3	$/lb Urea
21.30	$/ft3 Urea
2.85	$/gal Urea
1.424	$/gal 50% Urea Solution

NH3 Densities

19% Aqueous:	57.3 lb/ft3	7.66 lb/gal
29% Aqueous:	56.1 lb/ft3	7.50 lb/gal
99.5% Anhydrous:	38.15 lb/ft3	5.10 lb/gal
50% Urea:	71 lb/ft3	9.49 lb/gal

Pure NH3/Urea Costs:	600	$/ton**
Commodity Year:	2016	
Select NH3/Urea Type:	29.4% Aqueous	

Conversion checks using EPA CCM default assumption of $0.293:

Calculation Back Check If given $/gal - CCM Default back calculate:

266	$/ton NH3	**2016**
78.1	$/ton 29% aqueous solution	
0.039	$/lb	
2.19	$/ft3	
0.293	$/gal	

700	$/ton Urea	**Year?**
349.8	$/ton 50% Urea solution	
0.175	$/lb	
12.42	$/ft3	
1.660	$/gal	

**USGS NH3 commodity price statistics (cited in CCM SCR Chapter): https://www.usgs.gov/centers/nmic/nitrogen-statistics-and-information

Annual Emission Limits and Flares

We recommend that the draft permit is revised to include annual emission limitations (in tons per year) for all criteria pollutants. In addition, the potential flaring emissions from this facility are considerable. We recommend that any best practices identified in the "flaring minimization plan" (which is to be completed prior to operation) are made enforceable by ADEC through the permit conditions and that the state consider short-term operational limits for the flares.

Attachment C: NPS Authorities and Obligation to Comment on PSD Permits that May Affect Class I Areas

The 1977 Amendments to the Clean Air Act:

- Established the Prevention of Significant Deterioration (PSD) preconstruction permit program. The Alaska Department of Environmental Conservation (ADEC) is responsible for issuing PSD permits in the state under an EPA approved CAA state implementation plan (18 AAC 50.306).

- Designated Denali National Park (along with 48 other NPS units) as a *Class I area*. Class I areas are afforded additional protection and consideration under provisions of the Act.[15]

- Specified roles and responsibilities for the Federal Land Managing Agencies (FLMs) to ensure Class I protection goals are achieved (42 U.S.C. §7475):

    - Permitting authorities "*shall provide notice of the permit application to the Federal Land Manager and the Federal official charged with direct responsibility for management of any lands within a class I area which may be affected by emissions from the proposed facility.*" (§7475 (d)(2)(A))

    - FLMs "*shall have an affirmative responsibility to protect the air quality related values (including visibility) of any such lands within a class I area and to consider, in consultation with the Administrator, whether a proposed major emitting facility will have an adverse impact on such values.*" (§7475 (d)(2)(B))

    - Congress clarified its intent with respect to the FLM's CAA role in Senate Report No. 95-127, 95th Congress, 1st Session, 1977: "*The Federal Land Manager holds a powerful tool. He is required to protect Federal lands from deterioration of an established value, even when Class I [increments] are not exceeded. ... While the general scope of the Federal Government's activities in preventing significant deterioration has been carefully limited, the FLM should assume an aggressive role in protecting the air quality values of land areas under their jurisdiction. In cases of doubt the land manager should err on the side of protecting the air quality-related values for future generations.*"

[15] Initial classifications included national parks over 6, 000 acres and national wilderness areas over 5,000 acres that were in existence on August 7, 1977. The result was 158 "mandatory" Class I areas, managed by the National Park Service, the U.S. Fish and Wildlife Service (FWS) and the U.S. Forest Service. Tuxedni Wilderness, managed by the FWS, is also potentially affected by the AK LNG Liquefaction facility.