P.O. Box 196660 ANCHORAGE, ALASKA 99519-6660 TELEPHONE (907) 787-8700

July 28, 2025

Government Letter No. 57900
Delivered via Email

Alaska Department of Environmental Conservation
Air Permits Program
ATTN: Air Permit Application Intake Clerk
555 Cordova Street
Anchorage, Alaska 99501

Subject: Pump Station 4
Title V Permit No. AQ0075TVP04
Application to Renew Title V Operating Permit

Dear Air Permit Application Intake Clerk,

Alyeska Pipeline Services Company (APSC) is applying for a permit renewal under 40 CFR 71.5 and 18 AAC 50.326 for Air Quality Operating Permit No. AQ0075TVP04 for the Pump Station 3 (PS03) stationary source located on the North Slope of Alaska. Under Condition 87 of the permit, this renewal application is considered timely when submitted no earlier than July 20, 2025, and no later than July 20, 2026.

Application Organization

The Department's standard Title V operating permit application forms were used where relevant to prepare the renewal application. The application that accompanies this letter contains the following sections:

Form Series A

ADEC Title V Standard Form A1: Stationary Source General Information.

ADEC Title V Standard Form A2: Stationary Source Description. This form of the permit application applies to changes to the Form A2 data. For this application, this section is empty because there are no proposed changes.

ADEC Title V Standard Form A3: Operating Scenario Description. This form of the permit application applies to the operating scenarios for the stationary source. For this application, this section is empty because there are no proposed changes to the base operating scenario for the source.

ADEC Title V Standard Form A4: Title V Air Operating Permit Renewal Application Information. The supporting basis for requested revisions provided in Form E3 (see Form Series E, below) is the primary document that supports Form A4.

Form Series B

ADEC Title V Standard Forms B, B1, B2, and B4: Emission Unit Details. In these forms, all applicable emission unit-specific permit conditions are listed using the condition numbering of the current permit and changes to the emission unit-specific permit shields. Any limits or standards that are currently applicable to the stationary source but not yet included in the permit are also included in the forms as new conditions and clearly identified as such. A list of non-applicable requirements for specific emission units is also included on these forms. These are the requirements for which we request that the Department include a permit table that documents the permit shields granted.

Form Series C

ADEC Title V Standard Form C5: For the application, this section is blank because the stationary source does not employ the use of pollution control devices.

Form Series D

ADEC Title V Standard Form D1 and D2: Emission Unit Summary Forms and Stationary Source Emission Summary Forms, and Emissions Spreadsheets. As allowed per the Department's directions for this form, the emissions spreadsheets in lieu of providing detailed emissions information in Form D1 and D2 are provided. Criteria/GHG and HAP emissions estimates are provided in the Excel spreadsheets included with this application. Stationary source total emissions are summarized for significant and insignificant emission units.

Form Series E

ADEC Title V Standard Form E1: Stationary Source-Wide Applicable Requirements. This form documents all stationary-wide applicable permit conditions. In this form, we list all stationary source-wide permit conditions using the condition numbering of the current permit. New permit conditions, if applicable, are also included in the form and clearly identified as such.

ADEC Title V Standard Form E2: Permit-to-Operate and Minor Permit Condition Change Request. This form documents any specific requests to revise or remove conditions of an underlying construction permit. For this application, this section is empty because there are no requested changes.

ADEC Title V Standard Form E3: Title V Condition Change Request. This form documents all proposed/requested permit revisions. The basis for each proposed/requested permit revision is provided in Form E3.

ADEC Title V Standard Form E4: Permit Shield Request. All requested stationary source-wide permit shields included in the proposed permit are presented in this form.

ADEC Title V Standard Form E5: Alternative Monitoring Procedures. The performance test waiver granted by EPA for an NSPS Subpart GG-affected turbines at PS4 are summarized in, and attached to, this form.

Other Information

Current Permits. This section includes a copy of current Operating Permit No. AQ0075CPT01, AQ0075CPT02, AQ0075CPT03, AQ0075CPT04, AQ0075MSS01, AQ0075MSS02 and AQ0075TVP04.

2024 Stationary Source Compliance Certification.

Electronic Copy of Application.

If you have any questions, please contact me at 907-787-8897 or the application contact, Chris Lindsey with SLR International Corporation, at 907-264-6916.

Sincerely,

Hilary Garney
Air Quality SME

cc: Joseph Selby, APSC
Chris Lindsey, SLR

Part 70 Operating Permit Program, US EPA Region 10, Air Permits and Toxics Branch, Mail Stop: 15-H13, 1200 Sixth Avenue, Suite 155, Seattle, WA 98101-3188; (by email)

Enclosure: Title V Operating Permit Renewal Application

Application for Renewal of an Air Quality Operating Permit

Pump Station 4

Alyeska Pipeline Service Company

P.O. Box 196660
Anchorage, AK 99519-6660

Prepared by:

SLR International Corporation

2700 Gambell Street, Suite 200, Anchorage, Alaska, 99503

SLR Project No.: 105.021406.00001

Client Reference No: 0001

July 25, 2025

Revision: 0

Appendices

Appendix A Stationary Source

Application for Renewal of an Air Quality Operating Permit

Pump Station 4

Alyeska Pipeline Service Company

SLR Project No.: 105.021406.00001

July 25, 2025

A.1 Form A1: Stationary Source (General Information)

FORM A1

Stationary Source (General Information)

GENERAL INFORMATION

1. Permittee:

Permittee Name :Alyeska Pipeline Service Company

Mailing Address Line 1: P.O. Box 196660

Mailing Address Line 2

City: Anchorage State: AK Zip Code: 99519-6660

2. Stationary Source Name: Pump Station 4 (PS-4)

3. Stationary Source Physical Address :

Physical Address Line 1: 155 miles south of Prudhoe Bay, AK

Physical Address Line 2 Umiat Meridian

City: N/A State: AK Zip Code: N/A

4. Location Latitude: N 68° 25' 23" Longitude: W 149° 21' 18"

:Click here to enter text.

5. Primary SIC Code: 4612 SIC Code Description: Crude Oil Pipelines ***Primary NAICS Code: 4861101***

6. Current/Previous Title V Air Permit No.: AQ0075TVP04 Expiration Date: January 20, 2027

7. Does this application contain confidential data? ☐ Yes ☒ No

8. APPLICATION IS BEING MADE FOR:

☐ Initial Title V Permit for this Stationary Source ☐ Modify Title V Permit (currently permitted) ☒ Title V Permit Renewal

9. CONTACT INFORMATION (Attach additional sheets if needed)

Owner:	***Operator:***
Name/Title: See current permit	Name/Title: APSC
Mailing Address Line 1:	Mailing Address Line 1: See above
Mailing Address Line 2	Mailing Address Line 2
City: State: Zip Code:	City: State: Zip Code:
Permittee's Responsible Official:	***Designated Agent:***
Name/Title: Joseph Selby, Pipeline Director	Name/Title: CT Corporation
Mailing Address Line 1: Alyeska Pipeline Service Company	Mailing Address Line 1: 9360 Glacier Hwy
Mailing Address Line 2 P.O. Box 196660, MS575	Mailing Address Line 2 Suite 202
City: Anchorage State: AK Zip Code: 99519	City: Juneau State: AK Zip Code: 99801
Stationary Source and Building Contact:	***Fee Contact:***
Name/Title: Josh Millington/Tim Jones Maintenance Supervisor PS-3 and PS-4	Name/Title: Michelle Slwooko/Environmental Program Coordinator
Mailing Address Line 1:Pump Station 4	Mailing Address Line 1: Alyeska Pipeline Service Company
Mailing Address Line 2 P.O.Box 196660	Mailing Address Line 2 P.O. Box 196660, MS 507
City: Anchorage State: AK Zip Code: 99519-6660	City: Anchorage State: AK Zip Code: 99519-6660
Phone: 907 787-4402 Email Josh.Millingotn@ alyeska-pipeline.com /Tim.Jones@ alyeska-pipeline.com	Phone: 907-787-8906 Email: Michelle.Slwooko @alyeska-pipeline.com
Permit Contact:	***Person or Firm that Prepared Application:***
Name/Title: Hilary Garney/Air Quality SME	Name/Title: Chris Lindsey/AQ Consultant
Mailing Address Line 1: Alyeska Pipeline Service Company	Mailing Address Line 1: SLR International Corporation
Mailing Address Line 2 P.O. Box 196660	Mailing Address Line 2: 2700 Gambell Street, Suite 200
City: Anchorage State: AK Zip Code: 99519-6660	City: Anchorage State: AK Zip Code: 99503
Phone: 907-787-8897 Email: Hilary.garney@alyeska-pipeline.com	Phone: 907-264-6916 Email: clindsey@slrconsulting.com

10. STATEMENT OF 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.

Name of Responsible Official (typed): Joseph Selby Title: Pipeline Director

X Signature (blue ink): Date: 7-28-25

A.2 Form A4: Title V Air Operating Permit Renewal Application Information

FORM A4

Title V Air Operating Permit Renewal Application Information

Permit Number: AQ0075TVP04

1.	Permit Contact:	Name	Hilary Garney
		Title	Air Quality SME
		Mailing Address Line 1	Alyeska Pipeline Service Company
		Mailing Address Line 2	P.O. Box 196660, Anchorage, AK 99519-6660
		Phone Number	907-787-8897
		Email	Hilary.Garney@alyeska-pipeline.com
2.	Were there any changes to stationary source General Information (Form A1)? If yes, complete and submit a Form A1.		Yes, see Form A1.
3.	Were there any changes to the stationary source description (Form A2)? If yes, complete and submit a Form A2.		No.
4.	Were there any off-permit changes? Reference any notifications provided to the Department, and attach copies of the notifications.		No.
	If yes, integrate changes into renewal permit? [if no, explain]		N/A
5.	Have any Alaska Title I permits been issued to the stationary source since the most recent Title V permit or revision issuance?		No.
	If yes, integrate changes into renewal permit? [If yes, please list. If no, explain]		N/A.
6.	Will there be any changes to the operating scenario(s)? [if yes, describe and attach Form A3]		No.
7.	Will there be any new, modified, or reconstructed emission units or air pollution control equipment? [if yes, attach appropriate forms from Form Series B, C, D, and E]		No.
8.	Are the current emissions units correctly identified and defined in the permit? [if no, attach appropriate forms from Form Series B, C, D, and E]		Yes.
9.	Does the CAM rule [40 CFR Part 64] apply to any of the emissions units? [if yes, review the guidance provided for CAM in the Form A4 instructions for this item]		No.
10.	Does the accidental release prevention regulation [40 CFR Part 68] apply to the facility? [if yes, provide the appropriate regulatory applicability document in detail.]		No.
11.	Are there any other new applicable requirements? [if yes, list the new applicable requirements, emissions units, and attach the appropriate Series E Form]		No.

12.	Are there any requested changes in the assessable potential to emit other than those identified in item 9 above? [if yes, answer the following]	No.
	Are the changes a result of having better emissions information such as a new emission factor from a recent source test? [if yes, complete and attach any applicable emissions forms from Series D. Attach additional information as necessary to fully document.]	No.
	Are the changes due to an increase in production? [if yes, complete and attach the applicable emissions form from Series D. Attach additional information as necessary to fully document.]	No.
13.	Is the stationary source in compliance with all of the conditions of the current permit? If yes, attach a compliance certification. If no, attach a compliance schedule and/or actions taken for any out-of-compliance emission units.	Yes. See attached compliance certification.
14.	Are there any requested changes to testing and/or monitoring conditions? [if yes, identify the condition, the requested change, and the reason. Attach additional information as necessary to fully document.]	No.
15.	Are there any requested changes to monitoring conditions other than those being replaced by CAM? [if yes, identify the condition, the requested change, and the reason. Attach additional information as necessary to fully document.]	No.
16.	Are there any requested changes to recordkeeping conditions? [if yes, identify the condition, the requested change, and the reason. Attach additional information as necessary to fully document.]	No.
17.	Are there any requested changes to reporting conditions? [if yes, identify the condition, the requested change, and the reason. Attach additional information as necessary to fully document.]	No.
18.	Are there any requested changes to the non-applicable requirements (i.e. permit shield)? [if yes, identify the emission unit, the requested change, and the reason in the appropriate Series B and/or D form. If the change applies stationary source-wide, complete the appropriate Series E form. Attach additional information as necessary to fully document.]	No.

19.	Are there any other requested changes to any condition? [if yes, identify the condition, the requested change, and the reason. Attach additional information as necessary to fully document.]	Yes. See Form E3.

Statement of 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.

Joseph Selby
Name of Responsible Official

Pipeline Director
Title

Signature (blue ink)

7-28-25
Date

A.3 Attachment: Annual Compliance Certification

2024 Annual Compliance Certification Report
January 1, 2024, through December 31, 2024
Air Quality Operating Permit AQ0075TVP04
Pump Station 4

Permit Condition		Compliance Status	Method Used to Determine Status	Comments on Condition, Compliance Method, or Compliance Status
No(s).	**Summary/Description**			
Section 3: State Requirements				
1	Visible Emissions Standards - EU IDs 8-10, 12-15, 18, and 22	Continuous	Monitoring conducted under Conditions 2, 8, 11, and reasonable inquiry.	No VE Observations were conducted or required to be conducted during the reporting period. EU IDs 8, 9, and 12 burned gas as the primary fuel during the reporting period. EU IDs 10 and 14 did not trigger significant status during the reporting period. EU ID 13 burned only gas as fuel during the reporting period. EU IDs 15 and 22 did not exceed the operational limits in Table B. EU ID 18 had actual emissions less than the thresholds in 18 AAC 50.326(e) during the reporting period.
2-4	Visible Emissions Standards MR&R	Continuous	Reasonable inquiry/records.	No VE observations were conducted or required to be conducted during the reporting period.
5	Particulate Matter Emissions Standard - EU IDs 8-10, 12-15, 18, and 22	Continuous	Monitoring conducted under Condition 2, 8, 11, and reasonable inquiry.	No VE Observations were conducted or required to be conducted during the reporting period. EU IDs 8, 9, and 12 burned gas as the primary fuel during the reporting period. EU IDs 10 and 14 did not trigger significant status during the reporting period. EU ID 13 burned only gas as fuel during the reporting period. EU IDs 15 and 22 did not exceed the operational limits in Table B. EU ID 18 had actual emissions less than the thresholds in 18 AAC 50.326(e) during the reporting period.

Permit Condition		Compliance Status	Method Used to Determine Status	Comments on Condition, Compliance Method, or Compliance Status
No(s).	**Summary/Description**			
6-8	Particulate Matter Emissions Standards MR&R – EU IDs 10, 12, 14, 15, and 22	Continuous	Reasonable inquiry/records.	MR&R was conducted as required during the reporting period. No VE Observations were conducted or required to be conducted during the reporting period.
9-11	Particulate Matter Emissions Standards MR&R for Liquid Fuel-Burning Boilers and Heaters – EU IDs 8 and 9	Continuous	Reasonable inquiry/records.	MR&R was conducted as required during the reporting period. No VE Observations were conducted or required to be conducted during the reporting period.
12	Visible Emissions & Particulate Matter MR&R for Dual Fuel-Fired Emission Units – EU IDs 8, 9, and 12	Continuous	Reasonable inquiry/records	EU IDs 8, 9, and 12 did not exceed 400 hours of operation per year on liquid fuel during the reporting period.
13	Sulfur Compound Emissions Standard - EU IDs 8-10, 12-15, 18, and 22	Continuous	Monitoring conducted under Conditions 14 and 15.	Fuel gas contained 150 ppmv or less H_2S. Liquid fuel contained less than 0.2 wt% sulfur.
14	Sulfur Compound Emissions Standard MR&R – Liquid Fuel	Continuous	Reasonable inquiry/records.	MR&R conducted as required during the reporting period.
15	Sulfur Compound Emissions Standard MR&R – Gaseous Fuel	Continuous	Reasonable inquiry/records.	MR&R conducted as required during the reporting period.
16 (16.1)	Operational Limits – EU IDs 8 and 9	Continuous	Monitoring records under Condition 16.2.	EU IDs 8 and 9 did not exceed either operational limit during the reporting period.
16.2-16.5	Operational Limits MR&R	Continuous	Reasonable inquiry/records.	MR&R conducted as required during the reporting period.

Permit Condition		Compliance Status	Method Used to Determine Status	Comments on Condition, Compliance Method, or Compliance Status
No(s).	**Summary/Description**			
17	Tank 140 HAP Emissions ORL – EU ID 21	Continuous	Monitoring and recordkeeping conducted under Conditions 17.1 and 17.2.	EU ID 21 HAP emissions were less than the limits in Condition 17 during the reporting period.
17.1-17.2	Tank 140 HAP Emissions ORL MR&R	Continuous	Reasonable inquiry/records.	MR&R conducted as required during the reporting period.
18	Strategic Reconfiguration Authorization and Notification Requirements	Continuous	Reasonable inquiry/records.	This requirement has already been met.
19 (19.1 and 19.2)	Fuel Sulfur Limits – EU IDs 8-10, 12-15, 18, and 22	Continuous	Monitoring conducted under Conditions 19.1 and 19.2.	Fuel gas contained 150 ppmv or less H_2S. Liquid fuel contained less than 0.2 wt% sulfur.
19.1-19.2	Fuel Sulfur Limits MR&R	Continuous	Reasonable inquiry/records.	All MR&R conducted as required during the reporting period.
20	Operational Limits – EU IDs 12, 14, and 15	Continuous	Monitoring and recordkeeping conducted under Conditions 19.1 and 19.2.	No exceedances of the operational limits. EU IDs 12, 14, and 15 complied with the operational limits in Table B during the reporting period.
20.1-20.4	Operational Limits MR&R	Continuous	Reasonable inquiry/records.	All MR&R conducted as required during the reporting period.
21	Stack Parameters	Continuous	Reasonable inquiry/records.	No stack changes for EU ID 12 occurred during the reporting period.

Permit Condition		Compliance Status	Method Used to Determine Status	Comments on Condition, Compliance Method, or Compliance Status
No(s).	**Summary/Description**			
22 (22.1-22.3)	CO Emissions Limit – EU IDs 12 and 13	Continuous	Monitoring records under Condition 22.1, and monitoring conducted under Conditions 22.4-22.5.	EU IDs 12 and 13 complied with the operational limits in Table B, the load-based operating limits in Condition 22.2 and the intake temperature limit in Condition 22.3 during the reporting period.
22.4 - 22.9	Operational Limits MR&R	Continuous	Reasonable inquiry/records.	All MR&R requirements were met during the reporting period.
23 (23.1 and 23.2)	NOx Emissions Limits and MR&R Requirements – EU IDs 12, 14, 15 and 22	Continuous	Monitoring records under Conditions 20.1.	EU IDs 12, 14, and 15 complied with the operational limits in Table B during the reporting period. EU ID 22 complied with the limit in Condition 23.2. All MR&R requirements were met during the reporting period.
24	SO_2 Emissions Limit and MR&R Requirements – EU IDs 12, 14, and 15	Continuous	Monitoring records under Conditions 19 and 20.	EU IDs 12, 14, and 15 complied with the operational limits in Table B and the fuel sulfur limits in Condition 19 during the reporting period. All MR&R under Conditions 19 and 20 conducted as required, records maintained
25	Insignificant Emission Unit Requirements	Continuous	Reasonable inquiry.	Compliance with applicable emission standards based on reasonable inquiry. No insignificant emission unit had actual emissions greater than the thresholds in 18 AAC 50.326(e) during the reporting period. Also provided in the Facility Operating Reports as required.
Section 4: Federal Requirements				
26	NSPS Subpart A Notification Requirements	Continuous	Reasonable inquiry/records.	No notifications were submitted or required to be submitted during the reporting period.

Permit Condition		Compliance Status	Method Used to Determine Status	Comments on Condition, Compliance Method, or Compliance Status
No(s).	**Summary/Description**			
27	NSPS Subpart A Startup, Shutdown, Malfunction Requirements – EU IDs 12 and 13	Continuous	Reasonable inquiry/records.	SSM records are maintained electronically in Alyeska's data logger system and in the daily operator logs.
28-29	NSPS Subpart A Excess Emissions and Monitoring Systems Performance Reports – EU ID 12	Continuous	Reasonable inquiry/records.	Subpart A report for operation on diesel fuel was submitted as required.
30	NSPS Subpart A Performance Tests	Continuous	Reasonable inquiry.	No performance tests were requested by EPA during the reporting period.
31	NSPS Subpart A Good Air Pollution Control Practice – EU IDs 12 and 13	Continuous	Reasonable inquiry/records.	Alyeska complied with the routine maintenance procedures for EU IDs 12 and 13 during the reporting period. The units do not have air pollution control devices.
32	NSPS Subpart A Credible Evidence	Continuous	Reasonable inquiry.	Credible evidence is not a Part 70/71 applicable requirement.
33	NSPS Subpart A Concealment of Emissions	Continuous	Reasonable inquiry.	Alyeska does not conceal emissions. Stacks in good condition.
34 (34.1-34.2)	NSPS Subpart GG NO_X Emissions Standard – EU IDs 12 and 13	Continuous	Monitoring conducted under Condition 34.3, and reasonably inquiry.	Most recent periodic testing results indicate compliance with the standard. No source testing was conducted or required to be conducted during the reporting period.
34.3-34.5	NSPS Subpart GG NO_X Emissions MR&R	Continuous	Reasonable inquiry/records.	MR&R conducted as required during the reporting period. No load restrictions apply under Condition 34.3.c. No source testing was conducted or required to be conducted during the reporting period.

Permit Condition		Compliance Status	Method Used to Determine Status	Comments on Condition, Compliance Method, or Compliance Status
No(s).	**Summary/Description**			
35	NSPS Subpart GG SO_2 Emissions Standard – EU IDs 12 and 13	Continuous	Monitoring under Condition 35.1	Fuels combusted contained less than 0.8% sulfur by weight.
35.1-35.5	NSPS Subpart GG SO_2 Emissions Standard MR&R	Continuous	Reasonable inquiry/records.	Liquid fuel sampling conducted as required. Fuel gas meets the definition of natural gas and therefore no monitoring was required.
36	NSPS Subpart A Requirements – EU ID 22	Continuous	Reasonable inquiry.	Alyeska complied with Subpart A requirements as applicable to EU ID 22 during the permit term.
37	NSPS Subpart IIII Emissions Standards – EU ID 22	Continuous	Compliance requirements under Condition 39.4.	EU ID 22 was certified by the manufacturer to the emission standards.
38	NSPS Subpart IIII Fuel Requirements – EU ID 22	Continuous	Reasonable inquiry/records.	EU ID 22 burned only ULSD as fuel during the reporting period.
39	NSPS Subpart IIII Compliance Requirements	Continuous	Reasonable inquiry/records.	Alyeska operated and maintained EU ID 22 following manufacturer recommendations. No changes were made to EU ID 22 that would trigger source test requirements during the reporting period.
40	NSPS Subpart IIII Test Methods and Other Procedures	Continuous	Reasonable inquiry.	No performance tests were conducted or required to be conducted during the reporting period.
41	NSPS Subpart IIII Monitoring and Recordkeeping Requirements	Continuous	Reasonable inquiry	Alyeska complied with the requirements in Condition 41 during the reporting period.
42	NSPS Subpart IIII Reporting Requirements	Continuous	Reasonable inquiry	Alyeska complied with the requirements in Condition 42 during the reporting period.

Permit Condition		Compliance Status	Method Used to Determine Status	Comments on Condition, Compliance Method, or Compliance Status
No(s).	**Summary/Description**			
43	NESHAP Subpart A Requirements	Continuous	Reasonable inquiry.	Alyeska met all requirements of Subpart A identified in Table 8 of Subpart ZZZZ as applicable during the reporting period.
44	NESHAP Subpart ZZZZ Requirements – EU ID 22	Continuous	See Conditions 36-41	EU ID 22 complied with Subpart ZZZZ by complying with Subpart IIII under Conditions 36-41.
45	NESHAP Subpart ZZZZ Requirements – EU IDs 10, 14, and 15	Continuous	Reasonable inquiry/records	EU IDs 10, 14, and 15 complied with Subpart ZZZZ under Conditions 45.1 – 45.9.
45.1	NESHAP Subpart ZZZZ Management Practices for Emergency Engines – EU IDs 10 and 14	Continuous	Reasonable inquiry/records.	Alyeska met all the maintenance requirements in Condition 45.1.a – 45.1.c during the reporting period.
45.2	NESHAP Subpart ZZZZ Management Practices for Non-Emergency Engines – EU ID 15	Continuous	Reasonable inquiry/records.	Alyeska met all the maintenance requirements in Condition 45.2.a – 45.2.c during the reporting period.
45.3-45.6	NESHAP Subpart ZZZZ Requirements – EU IDs 10, 14 and 15	Continuous	Reasonable inquiry/records.	Alyeska operated EU IDs 10, 14, and 15 according to GAPCP and Condition 45.3. Alyeska met the operation and maintenance requirements in Condition 45.4. Oil analyses/changes were conducted as required in Condition 45.5. Alyeska met the emergency engine operating limitations in Condition 45.6.
45.7-45.8	NESHAP Subpart ZZZZ Monitoring and Recordkeeping Requirements	Continuous	Reasonable inquiry/records.	Alyeska met the requirements in Conditions 45.7 – 45.8 during the reporting period.

Permit Condition		Compliance Status	Method Used to Determine Status	Comments on Condition, Compliance Method, or Compliance Status
No(s).	**Summary/Description**			
45.9	NESHAP Subpart ZZZZ Reporting Requirements	Continuous	Reasonable inquiry/records.	Alyeska met the requirements in Condition 45.9 during the reporting period.
46	Subpart M - Asbestos NESHAP	Continuous	Reasonable inquiry/records.	Alyeska complied with the requirements of 40 CFR 61.145, 61.150, 61.152, Subpart M and applicable sections of Subpart A and Appendix A as required. No notifications were submitted or required to be submitted during the reporting period.
47-49	Protection of Stratospheric Ozone 40 CFR 82 Subparts F, G and H	Continuous	Reasonable inquiry/records.	Alyeska complied with the recycling and emissions reduction requirements in Subpart F, and the applicable prohibitions in Subpart G and Subpart H.
50	NESHAP Applicability Determinations	Continuous	Reasonable inquiry.	No NESHAP applicability determinations were submitted or required to be submitted during the reporting period.
Section 5: General Conditions				
51-53	Standard Terms and Conditions	Continuous	Reasonable inquiry.	No comments.
54	Administration Fees	Continuous	Reasonable inquiry/records.	Fees paid as required during the reporting period.
55-56	Assessable Emissions Estimates	Continuous	Reasonable inquiry/records.	Records document that the emission fee estimates were submitted to ADEC by March 31, 2024, and the emission fees paid.
57	Good Air Pollution Control Practices – EU IDs 8 and 9	Continuous	Reasonable inquiry/records.	For EU IDs 8 and 9, regular maintenance was conducted during the reporting period.
58	Dilution Prohibition	Continuous	Reasonable inquiry.	Alyeska does not dilute emissions to comply with conditions of this permit. Stacks are in good condition.

Permit Condition		Compliance Status	Method Used to Determine Status	Comments on Condition, Compliance Method, or Compliance Status
No(s).	**Summary/Description**			
59	Reasonable Precautions to Prevent Fugitive Dust	Continuous	Reasonable inquiry.	Precautions were taken as needed during the reporting period. No complaints were received during the reporting period regarding fugitive dust.
60	Stack Injection Prohibition	Continuous	Reasonable inquiry.	Only products of combustion or process emissions were released from applicable stacks.
61	Air Pollution Prohibited	Continuous	Reasonable inquiry/records.	No other complaints were received during the reporting period.
61.1-61.3	Air Pollution Prohibited MR&R	Continuous	Reasonable inquiry/records.	No complaints were received during the reporting period.
62	Technology-Based Emission Standard Excess Emissions Requirements	Continuous	Reasonable inquiry.	No unavoidable excess emissions occurred during the reporting period.
63	Open Burning Requirements	Continuous	Reasonable inquiry/records.	No open burning was conducted during the reporting period.
Section 6: General Source Testing and Monitoring Requirements				
64-73	Source Tests Requirements and Methods	Continuous	Reasonable inquiry.	No source tests were conducted or required to be conducted during reporting period.
Section 7: General Recordkeeping and Reporting Requirements				
74	General Recordkeeping Requirements	Continuous	Reasonable inquiry/records.	All recordkeeping requirements were met during the reporting period.
75	Certification of Documents	Continuous	Reasonable inquiry/records.	Alyeska certified all submittals subject to 18 AAC 50.205 submitted to ADEC and EPA during the reporting period.

Permit Condition		Compliance Status	Method Used to Determine Status	Comments on Condition, Compliance Method, or Compliance Status
No(s).	**Summary/Description**			
76-77	Submittals and Information Requests	Continuous	Reasonable inquiry/records.	Alyeska addressed submittals as required during the reporting period. No Information Requests were received during the reporting period.
78	Excess Emissions and Permit Deviation Reports	Continuous	Reasonable inquiry/records.	No excess emissions or permit deviation reports were submitted or required to be submitted during the reporting period.
79	Operating Reports	Continuous	Reasonable inquiry/records.	Records document that operating reports were submitted to ADEC in a timely manner and were consistent with the requirements of Conditions 79.1-79.5.
80	Annual Compliance Certification	Continuous	Reasonable inquiry/records.	2023 Annual Compliance Certification Report was submitted by March 31, 2024, as required.
81	Emission Inventory Reporting	Continuous	Reasonable inquiry/records.	Emission Inventory report submitted as required.
82	NSPS and NESHAP Reports	Continuous	Reasonable inquiry/records.	Copies of any reports submitted under 40 CFR 60, 61 or 63 during the reporting period included with operating report and submitted to EPA as required. Under Condition 82.2, no requests by ADEC occurred during the reporting period for any EPA-granted waivers.
Section 8: Permit Changes and Renewal				
83	Permit Applications and Submittals to EPA	Continuous	Reasonable inquiry/records.	EPA received copies of any permit applications and submittals as required.
84	Emissions Trading	Continuous	Reasonable inquiry.	PS 4 does not engage in emissions trading.

Permit Condition		Compliance Status	Method Used to Determine Status	Comments on Condition, Compliance Method, or Compliance Status
No(s).	**Summary/Description**			
85	Off Permit Changes	Continuous	Reasonable inquiry/records.	No off-permit change notifications were submitted or required to be submitted made during the reporting period.
86	Operational Flexibility	Continuous	Reasonable inquiry/records.	No operational flexibility changes were made during the reporting period.
87	Permit Renewal	Continuous	Reasonable inquiry.	No renewal permit applications were submitted during the reporting period.
Section 9: General Compliance Requirements				
88-93	General Compliance Requirements	Continuous	Reasonable inquiry.	No comments.

Notes:
1. Certification of compliance with underlying applicable requirements (continuous or intermittent status) during the reporting period is consistent with the monitoring requirements of the permit, and continuous compliance may be based on intermittent data.
2. N/A – not applicable; the condition is not an underlying applicable requirement or a supporting MR&R requirement, or the condition did not apply during the reporting period.
3. “Reasonable inquiry” may include but is not limited to process or operator knowledge; routine procedures; current and historical observations; and review of files, monitoring records or reports.
4. “Continuous” compliance means collection of all monitoring data required by the permit, with no deviations, and no other information that indicates deviations, except for unavoidable excess emissions or other operating conditions during which compliance is not required.

Appendix B Emission Units

Application for Renewal of an Air Quality Operating Permit

Pump Station 4

Alyeska Pipeline Service Company

SLR Project No.: 105.021406.00001

July 25, 2025

B.1 Form B: Emission Unit Listing for This Application

FORM B

Emission Unit Listing For This Application

Permit Number: AQ0075TVP04

EMISSION UNIT LISTING: New, Modified, Previously Unpermitted, Replaced, Deleted					
Emission Unit ID Number	Emission Unit Name	Brief Emission Unit Description	Rating/Size	Construction Date	Notes
Emission Units To Be ADDED By This Application (New, Previously Unpermitted, or Replacement)					
Emission Units To Be MODIFIED By This Application					
Emission Units To Be DELETED By This Application					
10	34-FP-2PK	Detroit Diesel 6-71 Firewater Pump	190 hp	Pre-1980	Decommiss-ioned October 2023.

FORM B

Emission Unit Listing For This Application

SIGNIFICANT EMISSION UNIT LISTING: Title V permitted emission units that have not been modified				
Emission Unit ID Number	Emission Unit Name	Brief Emission Unit Description	Rating/Size	Construction Date
8	34-H-1A	Eclipse Therminol Heater 1000-5 HCLT Design	20.6 MMBtu/hr	Pre-1980
9	34-H-1B	Eclipse Therminol Heater 1000-5 HCLT Design	20.6 MMBtu/hr	Pre-1980
12	34-PK-3701R	Siemens Cyclone Turbine Electric Generator, PK Model #SGT-400	12.9 MW	2005
13	34-PK-3601R	Siemens Cyclone Turbine Electric Generator, PK Model #SGT-400	12.9 MW	2005
14	34-GEN-3801R	Caterpillar 3516B Engine Electric Generator	2,250 kW	2005
15	34-GEN-4605R	UPS Electric Generator, PK Model #PPJD65MOD-1	65 kW	2005
18	N/A	11 Miscellaneous Shop Heaters	3.28 MMBtu/hr	2009
21	TK-140	Breakout Tank 140	55,000 bbl	Pre-1978
22	34-GEN-4401	MTU Detroit Electric Generator	800 kWe	2010

INSIGNIFICANT EMISSION UNIT LISTING: Insignificant Title V permitted emission units that have not been modified				
Emission	Brief Emission Unit Description	Rating/Size	Construction	Basis for Insignificant Status

FORM B

Emission Unit Listing For This Application

Unit Name			Date	
	Burnham PLQ Heater (2)	0.8 MMBtu/hr		18 AAC 50.326(g)(5)
	(8) Hastings Heaters	0.3 MMBtu/hr		18 AAC 50.326(g)(5)
	(9) Modine Heaters	0.5 MMBtu/hr		18 AAC 50.326(g)(5)
	Miscellaneous Shop Heaters (11)	3.3 MMBtu/hr		18 AAC 50.326(g)(5)
	Ground Heater	0.5 MMBtu/hr		18 AAC 50.326(g)(7)
	(2) Tioga Heaters	0.6 MMBtu/hr		18 AAC 50.326(g)(7)
	(2) Chinook Heaters	0.8 MMBtu/hr		18 AAC 50.326(g)(7)
	Aerotec Heater	0.4 MMBtu/hr		18 AAC 50.326(g)(7)

B.2 Form B1: Emission Unit Detail Form – External Combustion Equipment

FORM B1

Emission Unit Detail Form – External Combustion Equipment (Boilers and Heaters)

Permit Number: AQ0075TVP04

1.	Emission Unit ID Number // Operating Scenario	EU ID 8 and 9 // Operating Scenario 1
2.	Date installation/construction commenced	Pre-1980
3.	Date installed	Pre-1980
4.	Emission Unit serial number	34-H-1A and 34-H-1B (respective tag numbers)
5.	Special control requirements? [if yes, describe]	NA
6.	Manufacturer	Eclipse
7.	Description of emission unit, including type of boiler/heater and firing method: Eclipse Therminol Heater, 1000-5 HCLT Design (2). EU IDs 8 and 9 fire natural gas as the primary fuel and are capable of firing diesel fuel.	
8.	Rated design capacity (heat input, MMBtu/hr)	20.6 MMBtu/hr
9.	Maximum steam production rate (lbs/hr)	
10.	Maximum steam pressure (psi)	
11.	Maximum steam temperature (°F)	

12. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Diesel fuel	154 gal/hr, each
Natural gas	23,870 scf/hr, each

13.	Is waste heat utilized for any purpose? If yes, describe:

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0075TVP04, Condition 1	18 AAC 50.040(j), 50.055(a)(1), & 50.326(j) 40 CFR 71.6(a)(1)	Visible Emissions Standard	20% average over any six consecutive minutes.	Yes	Conditions 1.4 and 12, Standard Permit Conditions VIII & IX
AQ0075TVP04, Condition 5	18 AAC 50.040(j), 50.055(b)(1), & 50.326(j)	Particulate Matter Emissions Standard	Shall not exceed 0.05 grains per cu. ft. of exhaust corrected to	Yes	Conditions 5.4 and 9 through 12, Standard Permit Conditions VIII & IX
AQ0075TVP04, Condition 13	18 AAC 50.040(j), 50.055(c), & 50.326(j) 40 CFR 71.6(a)(1)	Sulfur Compund Emissions Standard	SO_2 emissions not to exceed 500 ppm averaged over three hours	Yes	Conditions 14, 15, 19.1 and 19.2, Standard Permit Condition XI
AQ0075TVP04, Condition 16, 16.1	Permit-to-Operate No. 9572-AA009, Amendment 2 18 AAC 50.040(j) & 50.326(j) 40 CFR 71.6(a)	Preconstruction Permit Requirements	16.1.a. Combined total operating time for EU IDs 8 & 9 not to exceed 1,000 hours per 12 month period on liquid fuel, or 16.1.b. combined total gallons for EU IDs 8 & 9 no to exceed 159,000 gallons per 12 month period on liquid fuel.	Yes	Conditions 16.2 through 16.4
AQ0075TVP04, Condition 19, 19.1	Permit No. AQ0075CPT02 40 C.F.R. 71.6(a)(3) & (c)(6)	Ambient Air Quality Protection Requirements Fuel Sulfur Limits	Comply with SO_2 ambient air quality standards by limiting the hydrogen sulfide (H_2S) concentration of fuel gas to no greater than 150 parts per million by volume (ppmv).	Yes	Condition 19.1a through 19.1d

FORM B1

Emission Unit Detail Form – External Combustion Equipment (Boilers and Heaters)

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0075TVP04, Condition 19, 19.2	Permit No. AQ0075CPT02 40 C.F.R. 71.6(a)(3) & (c)(6)	Ambient Air Quality Protection Requirements Fuel Sulfur Limits	Comply with SO_2 ambient air quality standards by limiting the diesel fuel sulfur content to no greater than 0.20 percent by weight.	Yes	Condition 19.2a through 19.2d
AQ0075TVP04, Condition 57	18 AAC 50.326(j)(3) & 50.346(b)(5)	Good Air Pollution Control Practice	Perform regular maintenance and recordkeeping	Yes	Conditions 57.1 through 57.3, Standard Permit Condition VI

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial Institutional Steam Generating Units	Construction of EU IDs 8 and 9 commenced prior to June 9, 1989. EU IDs 8 and 9 have not been reconstructed or modified.
40 CFR 63, Subpart JJJJJJ	EU IDs 8 and 9 burn diesel only as backup fuel. EU IDs 8 and 9 are exempt from the requirements of 40 CFR 63, Subpart JJJJJJ.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B1

Emission Unit Detail Form – External Combustion Equipment (Boilers and Heaters)

Permit Number: AQ0075TVP04

1.	Emission Unit ID Number // Operating Scenario	EU ID 18 // Operating Scenario 1
2.	Date installation/construction commenced	
3.	Date installed	2009
4.	Emission Unit serial number	
5.	Special control requirements? [if yes, describe]	
6.	Manufacturer	Various
7.	Description of emission unit, including type of boiler/heater and firing method: Natural gas-fired space heaters (11)	
8.	Rated design capacity (heat input, MMBtu/hr)	3.28 MMBtu/hr combined
9.	Maximum steam production rate (lbs/hr)	
10.	Maximum steam pressure (psi)	
11.	Maximum steam temperature (°F)	

12. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Natural Gas	3.28 MMBtu/hr

13.	Is waste heat utilized for any purpose? If yes, describe:

FORM B1

Emission Unit Detail Form – External Combustion Equipment (Boilers and Heaters)

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0075TVP04, Condition 1	18 AAC 50.040(j) 50.055(a)(1), & 50.326(j) 40 CFR 71.6(a)(1)	Visible Emissions Standard	20% average over any six consecutive minutes.	Yes	Condition 1.3, Standard Permit Condition IX
AQ0075TVP04, Condition 5	18 AAC 50.040(j), 50.055(b)(1), & 50.326(j)	PM Emission Standards	Shall not exceed 0.05 grains per cu. ft. of exhaust	Yes	Condition 5.3, Standard Permit Condition IX
AQ0075TVP04, Condition 13	18 AAC 50.040(j), 50.055(c), 50.326(j) 40 CFR 71.6(a)(1)	Sulfur Compound Emissions Standard	SO_2 not to exceed 500 ppm averaged over three hours	Yes	Conditions 15, 19.1, Standard Permit Condition XI
AQ0075TVP04, Condition 18	Minor Permit AQ0075MSS02, 18 AAC 50.040(j), 50.326(j), 40 CFR 71.6(a)	Installation Authorization and Startup Notification Requirements under Strategic Reconfiguration	See Condition 18	Yes	Conditions 18.1 through 18.4
AQ0075TVP04, Condition 19, 19.1	Permit No. AQ0075CPT02 40 C.F.R. 71.6(a)(3) & (c)(6)	Ambient Air Quality Protection Requirements Fuel Sulfur Limits	Comply with SO_2 ambient air quality standards by limiting the hydrogen sulfide (H_2S) concentration of fuel gas to no greater than 150 parts per million by volume	Yes	Condition 19.1a through 19.1d

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

B.3 Form B2: Emission Unit Detail Form – Internal Combustion Equipment

FORM B2
Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit Number: AQ0075TVP04

1.	Emission Unit ID Number // Operating Scenario	EU ID 12 // Operating Scenario 1
2.	Date installation/construction commenced[1]	2005
3.	Date installed	
4.	Emission Unit serial number	34-PK-3701R
5.	Special control requirements? [if yes, describe]	
6.	Manufacturer and model number	Siemens Cyclone, PK Model #SGT-400
7.	Type of combustion device	Gas Turbine
8.	Rated design capacity (horsepower rating for engines)	
9.	Rated design capacity (heat input, MMBtu/hr rating for turbines)	
10.	If used for power generation, electrical output (kW)	12,900 kW (12.9 MW) ISO

1. See page 2 of the Form B instructions regarding installation/construction date and consult regulations under 40 C.F.R. 60 (NSPS) and 40 C.F.R. 63 (NESHAP) for applicability dates, e.g.,
- NSPS Subparts IIII and JJJJ, and NESHAP Subpart ZZZZ for engines, and
- NSPS Subparts GG and KKKK, and NESHAP Subpart YYYY for turbines.
Note that other regulations may apply in addition to the regulations cited.

11. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Natural gas	136.4 Mscf/hr
Diesel	922.2 gal/hr

12.	Describe any specific modifications to the emission unit that must be addressed in the permit:

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0075TVP04, Condition 1	18 AAC 50.040(j), 50.055(a)(1), &	Visible Emissions Standard	20% average over any six consecutive minutes.	Yes	Conditions 1.4, 12, Standard Permit Conditions VIII & IX
AQ0075TVP04, Condition 5	18 AAC 50.040(j), 50.055(b)(1), & 50.326(j) 40 CFR 71.6(a)(1)	Particulate Matter Emissions Standard	Shall not exceed 0.05 grains per cu. ft. of exhaust corrected to standard conditions and averaged over three hours	Yes	Conditions 5.4, 6 through 8, 12, Standard Permit Conditions VIII & IX
AQ0075TVP04, Condition 13	18 AAC 50.040(j), 50.055(c), & 50.326(j) 40 CFR 71.6(a)(1)	Sulfur Compund Emissions Standard	SO_2 emissions not to exceed 500 ppm averaged over three hours	Yes	Conditions 14, 15, 19.1, 19.2, Standard Permit Condition XI
AQ0075TVP04, Condition 18	Minor Permit AQ0075MSS02, 18 AAC 50.040(j), & 50.326(j)	Dry Low Emissions Technology	Configure EU ID 12 with Dry Low Emissions (DLE) Technology	Yes	Condition 18.1 through 18.4
AQ0075TVP04, Condition 19, 19.1	Permit No. AQ0075CPT02 40 C.F.R. 71.6(a)(3) & (c)(6)	Ambient Air Quality Protection Requirements Fuel Sulfur Limits	Comply with SO_2 ambient air quality standards by limiting the hydrogen sulfide (H_2S) concentration of fuel gas to no greater than 150 parts per million by volume (ppmv).	Yes	Condition 19.1a through 19.1d

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0075TVP04, Condition 19, 19.2	Permit No. AQ0075CPT02 40 C.F.R. 71.6(a)(3) & (c)(6)	Ambient Air Quality Protection Requirements Fuel Sulfur Limits	Comply with SO_2 ambient air quality standards by limiting the diesel fuel sulfur content to no greater than 0.20 percent by weight.	Yes	Condition 19.2a through 19.2d, 24
AQ0075TVP04, Condition 20	Minor Permits AQ0075MSS02, Construction Permit AQ0075CPT02 , 18 AAC 50.040(j), 50.326(j), 40 CFR 71.6(a)	Ambient Air Quality Protection	Do not exceed 240 hours of operation on diesel fuel per 12 consecutive month period	Yes	Conditions 20.1 through 20.4, 23 and 24
AQ0075TVP04, Condition 21	Construction Permit AQ0075CPT02, 18 AAC 50.040(j), 50.326(j), 40 CFR 71.6(a)	Stack Parameters	Maintain the exhaust stack height to at least 51 feet above gravel pad elevation	Yes	Condition 21
AQ0075TVP04, Condition 22, 22.1	Construction Permit AQ0075CPT02	CO Emissions Limit	See Condition 22	Yes	Conditions 22.2 through 22.9

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0075TVP04, Condition 27	18 AAC 50.040(a)(1), 40 CFR 60.7(b), Subpart A & 71.6(a)(3)(ii)(B)	NSPS Subpart A Startup, Shutdown, & Malfunction Requirements	Maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of EUs 12 and 13 and malfunctions of associated air-pollution control equipment, or any periods which a continuous monitoring system or monitoring device for EU IDs 12 and 13 is inoperative.	Yes	Condition 27
AQ0075TVP04, Condition 28	18 AAC 50.040(a)(1) 40 C.F.R. 60.7(c), Subpart A	NSPS Subpart A Excess Emissions and Monitoring Systems Performance Report	Submit to the Department and to EPA "excess emissions and monitoring systems performance (EEMSP) report" any time a limit in Conditions 34 and 35 has been exceeded as described in Conditions 28.1 and 28.2 and / or summary report described in Condition 29 for EU ID 12 (only when fired with diesel fuel).	Yes	Condition 28.1, 28.2, 29

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0075TVP04, Condition 30	18 AAC 50.040(a)(1) 40 C.F.R. 60.8(a), Subpart A	NSPS Subpart A Performance (Source) Tests	Conduct source tests according to Section 6 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.	Yes	Conditions 30.1 through 30.4
AQ0075TVP04, Condition 31	18 AAC 50.040(a)(1) 40 CFR 60.11(d), Subpart A	NSPS Subpart A Good Air Pollution Control Practice	Maintain air pollution control equipment in a manner consistent with good air pollution control practice.	Yes	Condition 31
AQ0075TVP04, Condition 32	18 AAC 50.040(a)(1) 40 CFR 60.11(g), Subpart A	NSPS Subpart A Credible Evidence	Credible evidence or information can be used to demonstrate compliance with 40 CFR Part 60 requirments.	Yes	Condition 32
AQ0075TVP04, Condition 33	18 AAC 50.040(a)(1) 40 CFR 60.12, Subpart A	NSPS Subpart A Concealment of Emissions	Do not build, erect, install or use any article, machine, equipment or process to conceal emissions.	Yes	Condition 33

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0075TVP04, Condition 34	18 AAC 50.040(a)(2)(V) 40 CFR 60.332(a)(2) & (d), Subpart GG	NSPS Subpart GG NOx Emissions Standard	Natural gas fired: NOx not to exceed 212 ppmv at 15% Oxygen (O_2) dry exhaust basis. Diesel fired: NOx not to exceed 205 ppmv at 15% Oxygen (O_2) dry exhaust basis	Yes	Conditions 28, 29 and 34.1 through 34.5
AQ0075TVP04, Condition 35	18 AAC 50.040(a)(2)(V) 40 CFR 60.333, Subpart GG	NSPS Subpart GG SO_2 Emissions Standard	SO_2 not to exceed 0.8 percent by weight	Yes	Conditions 28, 29 and 35.2 through 35.5
AQ0075TVP04, Condition 62	18 AAC 50.235(a), 50.326(j)(4), & 50.040(j)(4) 40 CFR 71.6(c)(6)	Technology Based Emission Standard	Minimize levels of emissions that exceed the standard	Yes	Conditions 62.1 and 62.2

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 60 Subpart A – General Provisions (portions of)	§60.7(a)(5) – (a)(7) – Do not apply because no continuous monitoring system is used. Opacity observation is not required because visible emissions are not regulated under Subpart GG. §60.13 – Does not apply because no continuous monitoring system or monitoring device as each term is defined in 60.2 is required under Subpart GG for EU IDs 12 and 13.
40 CFR 60 Subpart GG – Standards of Performance for Stationary Gas Turbines:	Standards for NOx: §60.332(a)(1) – Does not apply because EU IDs 12 and 13 are subject to §60.332(a)(2). §60.332(3) & (a)(4) – Do not apply because APSC has chosen not to take an allowance for fuel-bound nitrogen. Standard for Sulfur Dioxide: §60.333(a) – Does not apply because APSC has chosen to comply with the sulfur limit under §60.333(b). Monitoring of Operations: §60.334(a) and (b) – Apply only to turbines using water injection for NOx control. §60.334(c)-(g) – Optional monitoring methods (CEMS) that APSC chooses not to conduct. §60.334(h)(2) – Nitrogen monitoring under 60.334(h)(2) is not required because APSC has chosen not to claim an allowance for fuel bound nitrogen. §60.334(j) – Does not apply to EU IDs 12 (only when fired with natural gas) and 13 because no continuous monitoring of parameters or emissions is required.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit Number: AQ0075TVP04

1.	Emission Unit ID Number // Operating Scenario	EU ID 13 // Operating Scenario 1
2.	Date installation/construction commenced[1]	2005
3.	Date installed	
4.	Emission Unit serial number	34-PK-3601R
5.	Special control requirements? [if yes, describe]	NA
6.	Manufacturer and model number	Siemens Cyclone, PK Model #SGT-400
7.	Type of combustion device	NG-fired combustion turbine
8.	Rated design capacity (horsepower rating for engines)	
9.	Rated design capacity (heat input, MMBtu/hr rating for turbines)	
10.	If used for power generation, electrical output (kW)	12,900 kW (12.9 MW) ISO

1. See page 2 of the Form B instructions regarding installation/construction date and consult regulations under 40 C.F.R. 60 (NSPS) and 40 C.F.R. 63 (NESHAP) for applicability dates, e.g.,
- NSPS Subparts IIII and JJJJ, and NESHAP Subpart ZZZZ for engines, and
- NSPS Subparts GG and KKKK, and NESHAP Subpart YYYY for turbines.

Note that other regulations may apply in addition to the regulations cited.

11. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Natural gas	136.4 Mscf/hr

12.	Describe any specific modifications to the emission unit that must be addressed in the permit:

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0075TVP04, Condition 1	18 AAC 50.040(j) 50.055(a)(1), & 50.326(j) 40 CFR 71.6(a)(1)	Visible Emissions Standard	20% average over any six consecutive minutes.	Yes	Condition 1.5, Standard Permit Condition VIII
AQ0075TVP04, Condition 5	18 AAC 50.040(j), 50.055(b)(1), & 50.326(j) 40 CFR 71.6(a)(1)	PM Emission Standards	Shall not exceed 0.05 grains per cu. ft. of exhaust corrected to standard conditions and averaged over three	Yes	Condition 5.5, Standard Permit Condition VIII
AQ0075TVP04, Condition 13	18 AAC 50.040(j), 50.055(c), 50.326(j) 40CFR71.6(a)(1)	Sulfur Compound Emissions Standard	SO2 not to exceed 500 ppm averaged over three hours	Yes	Conditions 15 and 19.1
AQ0075TVP04, Condition 18	Minor Permit AQ0075MSS02, 18 AAC 50.040(j), & 50.326(j) 40 CFR 71.6(a)	Dry Low Emissions Technology	Configure EU ID 13 with Dry Low Emissions (DLE) Technology	Yes	Condition 18.1 through 18.4
AQ0075TVP04, Condition 19, 19.1	Permit No. AQ0075CPT02 40 C.F.R. 71.6(a)(3) & (c)(6)	Ambient Air Quality Protection Requirements Fuel Sulfur Limits	Comply with SO_2 ambient air quality standards by limiting the hydrogen sulfide (H_2S) concentration of fuel gas to no greater than 150 parts per million by volume (ppmv).	Yes	Condition 19.1a through 19.1d
AQ0075TVP04, Condition 22, 22.2	Construction Permit AQ0075CPT02	CO Emissions Limit	See Condition 22	Yes	Conditions 22.3 through 22.9

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0075TVP04, Condition 27	18 AAC 50.040(a)(1) 40 CFR 60.7(b), Subpart A & 71.6(a)(3)(ii)(B)	NSPS Subpart A Startup, Shutdown, & Malfunction Requirements	Maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of EUs 12 and 13 and malfunctions of associated air-pollution control equipment, or any periods which a continuous monitoring system or monitoring device for EU IDs 12 and 13 is inoperative.	Yes	Condition 27
AQ0075TVP04, Condition 28	18 AAC 50.040(a)(1) 40 C.F.R. 60.7(c), Subpart A	NSPS Subpart A Excess Emissions and Monitoring Systems Performance Report	Submit to the Department and to EPA "excess emissions and monitoring systems performance (EEMSP) report" any time a limit in Conditions 34 and 35 has been exceeded as described in Condition and 28.2.	Yes	Condition 28.1, 28.2, 29

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0075TVP04, Condition 30	18 AAC 50.040(a)(1) 40 C.F.R. 60.8(a), Subpart A	NSPS Subpart A Performance (Source) Tests	Conduct source tests according to Section 6 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.	Yes	Conditions 30.1 through 30.4
AQ0075TVP04, Condition 31	18 AAC 50.040(a)(1) 40 CFR 60.11(d), Subpart A	NSPS Subpart A Good Air Pollution Control Practice	Maintain air pollution control equipment in a manner consistent with good air pollution control practice.	Yes	Condition 31
AQ0075TVP04, Condition 32	18 AAC 50.040(a)(1) 40 CFR 60.11(g), Subpart A	NSPS Subpart A Credible Evidence	Credible evidence or information can be used to demonstrate compliance with 40 CFR Part 60 requirments.	Yes	Condition 32

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0075TVP04, Condition 33	18 AAC 50.040(a)(1) 40 CFR 60.12, Subpart A	NSPS Subpart A Concealment of Emissions	Do not build, erect, install or use any article, machine, equipment or process to conceal emissions.	Yes	Condition 33
AQ0075TVP04, Condition 34, 34.1	18 AAC 50.040(a)(2)(V) 40 CFR 60.332(a)(2) & (d), Subpart GG	NSPS Subpart GG NOx Emissions Standard	NOx not to exceed 212 ppmv at 15% Oxygen (O_2) dry exhaust basis	Yes	Conditions 28, 29, 34.3 through 34.5
AQ0075TVP04, Condition 35, 35.1	18 AAC 50.040(a)(2)(V) 40 CFR 60.333, Subpart GG	NSPS Subpart GG SO_2 Emissions Standard	SO_2 not to exceed 0.8% by weight	Yes	Conditions 28, 29, 35.2 through 35.5
AQ0075TVP04, Condition 62	18 AAC 50.235(a), 50.326(j)(4), & 50.040(j)(4) 40 CFR 71.6(c)(6)	Technology Based Emission Standard	Minimize levels of emissions that exceed the standard	Yes	Conditions 62.1 and 62.2

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 60 Subpart A – General Provisions (portions of)	§60.7(a)(5) – (a)(7) – Do not apply because no continuous monitoring system is used. Opacity observation is not required because visible emissions are not regulated under Subpart GG. §60.13 – Does not apply because no continuous monitoring system or monitoring device as each term is defined in 60.2 is required under Subpart GG for EU IDs 12 and 13.
40 CFR 60 Subpart GG – Standards of Performance for Stationary Gas Turbines:	Standards for NOx: §60.332(a)(1) – Does not apply because EU IDs 12 and 13 are subject to §60.332(a)(2). §60.332(3) & (a)(4) – Do not apply because APSC has chosen not to take an allowance for fuel-bound nitrogen. Standard for Sulfur Dioxide: §60.333(a) – Does not apply because APSC has chosen to comply with the sulfur limit under §60.333(b). Monitoring of Operations: §60.334(a) and (b) – Apply only to turbines using water injection for NOx control. §60.334(c)-(g) – Optional monitoring methods (CEMS) that APSC chooses not to conduct. §60.334(h)(2) – Nitrogen monitoring under 60.334(h)(2) is not required because APSC has chosen not to claim an allowance for fuel bound nitrogen. §60.334(j) – Does not apply to EU IDs 12 (only when fired with natural gas) and 13 because no continuous monitoring of parameters or emissions is required.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit Number: AQ0075TVP04

1.	Emission Unit ID Number // Operating Scenario	EU ID 14 // Operating Scenario 1
2.	Date installation/construction commenced[1]	2005
3.	Date installed	
4.	Emission Unit serial number	34-GEN-3801R
5.	Special control requirements? [if yes, describe]	
6.	Manufacturer and model number	Caterpillar 3516B
7.	Type of combustion device	Reciprocating internal combustion engine
8.	Rated design capacity (horsepower rating for engines)	
9.	Rated design capacity (heat input, MMBtu/hr rating for turbines)	
10.	If used for power generation, electrical output (kW)	2,250 kW

1. See page 2 of the Form B instructions regarding installation/construction date and consult regulations under 40 C.F.R. 60 (NSPS) and 40 C.F.R. 63 (NESHAP) for applicability dates, e.g.,
- NSPS Subparts IIII and JJJJ, and NESHAP Subpart ZZZZ for engines, and
- NSPS Subparts GG and KKKK, and NESHAP Subpart YYYY for turbines.
Note that other regulations may apply in addition to the regulations cited.

11. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Diesel	147 gal/hr

12.	Describe any specific modifications to the emission unit that must be addressed in the permit:

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0075TVP04, Condition 1	18 AAC 50.040(j) 50.055(a)(1), & 50.326(j) 40 CFR 71.6(a)(1)	Visible Emissions Standard	20% average over any six consecutive minutes.	Yes	Conditions 1.2, 2 through 4, Standard Permit Condition IX
AQ0075TVP04, Condition 5	18 AAC 50.040(j), 50.055(b)(1), & 50.326(j) 40 CFR 71.6(a)(1)	PM Emission Standards	Shall not exceed 0.05 grains per cu. ft. of exhaust corrected to standard conditions and averaged over three hours.	Yes	Conditions 5.2, 6 through 8, Standard Permit Condition IX
AQ0075TVP04, Condition 13	18 AAC 50.040(j), 50.055(c), 50.326(j) 40CFR71.6(a)(1)	Sulfur Compound Emissions Standard	SO_2 not to exceed 500 ppm averaged over three hours	Yes	Conditions 14, 19.2, Standard Permit Condition XI
AQ0075TVP04, Condition 19, 19.2	Permit No. AQ0075CPT02 40 C.F.R. 71.6(a)(3) & (c)(6)	Ambient Air Quality Protection Requirements Fuel Sulfur Limits	Comply with SO_2 ambient air quality standards by limiting the diesel fuel sulfur content to no greater than 0.20 percent by weight.	Yes	Condition 19.2a through 19.2d, 24
AQ0075TVP04, Condition 20	Minor Permits AQ0075MSS02, Construction Permit AQ0075CPT02 , 18 AAC 50.040(j), 50.326(j), 40 CFR 71.6(a)	Ambient Air Quality Protection	Do not exceed 600 hours of operation per 12 consecutive month period	Yes	Conditions 20.1 through 20.4, 23 and 24

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0075TVP04, Condition 43	18 AAC 50.040(c)(23), (j), & 50.326(j) 40 CFR 71.6(a)(1) 40 CFR 63.6585 and 63.6590(c), Subpart ZZZZ	NESHAP Subpart ZZZZ Applicability	Comply with the applicable requirements of NESHAP Subpart ZZZZ	Yes	Condition 43.1, 45

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	Not affected units (unless modified or reconstructed in the future). These emission units were manufactured prior to April 1, 2006 applicability date (see 40 C.F.R. 60.4200(a)(2(i)), and have not been modified or reconstructed after July 11, 2005 (see 40 C.F.R. 60.4200(a)(3)).
40 CFR Subpart ZZZZ §§63.6600, 63.6601, 63.6602, 63.6610, 63.6611	Requirements apply to affected units located at a major source. PS 4 is an area source of HAP emissions.
40 C.F.R. Subpart ZZZZ emission limitations and operating limitations under Table 2b referenced by §63.6603(a) §63.6604 §§63.6612, 63.6615, and 63.6620 §§63.6625(a)-(d), §63.6625(g) §63.6630 §§63.6640(b) & (e) §§63.6645(a) §§63.6645(b)-(h) §§63.6655(a) & (b) §63.6655(c)	Emergency CI RICE located at area sources are not subject to the numerical CO emissions limitations or the operating limitations related to oxidation catalysts in Table 2b. Emergency RICE are not subject to the fuel requirements under 63.6604 The performance test requirements and initial compliance demonstrations do not apply to emergency RICE not subject to numerical CO emission standards. Requirements apply to RICE using CEMS or CPMS to demonstrate compliance, to RICE burning landfill or digester gas, or to emergency RICE located at a major source of HAP emissions Emergency RICE are not subject to the crankcase control requirements under 63.6604. Does not apply because emergency RICE are not subject to numerical CO emission standards. Reporting requirements apply to RICE subject to an emission limitation or operating limitation. Per 63.6645(a)(5), notification requirements do not apply to emergency RICE. Notification requirements apply to RICE located at HAP major sources, or to RICE required to conduct a performance test or other initial compliance demonstration. These recordkeeping requirements only apply to RICE subject to an emission or operating limitation. These recordkeeping requirements only apply to RICE burning landfill or digester gas.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit Number: AQ0075TVP04

1.	Emission Unit ID Number // Operating Scenario	EU ID 15 // Operating Scenario 1
2.	Date installation/construction commenced[1]	2005
3.	Date installed	
4.	Emission Unit serial number	34-GEN-4605R
5.	Special control requirements? [if yes, describe]	
6.	Manufacturer and model number	UPS Electric Generator PK Model #PPJD65MOD-1
7.	Type of combustion device	Reciprocating internal combustion engine
8.	Rated design capacity (horsepower rating for engines)	
9.	Rated design capacity (heat input, MMBtu/hr rating for turbines)	
10.	If used for power generation, electrical output (kW)	65 kWe

1. See page 2 of the Form B instructions regarding installation/construction date and consult regulations under 40 C.F.R. 60 (NSPS) and 40 C.F.R. 63 (NESHAP) for applicability dates, e.g.,
- NSPS Subparts IIII and JJJJ, and NESHAP Subpart ZZZZ for engines, and
- NSPS Subparts GG and KKKK, and NESHAP Subpart YYYY for turbines.
Note that other regulations may apply in addition to the regulations cited.

11. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Diesel	4.25 gal/hr

12.	Describe any specific modifications to the emission unit that must be addressed in the permit:

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0075TVP04, Condition 1	18 AAC 50.040(j) 50.055(a)(1), & 50.326(j) 40 CFR 71.6(a)(1)	Visible Emissions Standard	20% average over any six consecutive minutes.	Yes	Conditions 1.1, 1.2, 2 through 4, Standard Permit Condition IX
AQ0075TVP04, Condition 5	18 AAC 50.040(j), 50.055(b)(1), & 50.326(j) 40 CFR 71.6(a)(1)	PM Emission Standards	Shall not exceed 0.05 grains per cu. ft. of exhaust corrected to standard conditions and averaged over three hours.	Yes	Conditions 5.1, 5.2, 6 through 8, Standard Permit Condition IX
AQ0075TVP04, Condition 13	18 AAC 50.040(j), 50.055(c), 50.326(j) 40 CFR 71.6(a)(1)	Sulfur Compound Emissions Standard	SO_2 not to exceed 500 ppm averaged over three hours.	Yes	Conditions 14, 19.2, Standard Permit Condition XI
AQ0075TVP04, Condition 19, 19.2	Permit No. AQ0075CPT02 40 C.F.R. 71.6(a)(3) & (c)(6)	Ambient Air Quality Protection Requirements Fuel Sulfur Limits	Comply with SO_2 ambient air quality standards by limiting the diesel fuel sulfur content to no greater than 0.20 percent by weight.	Yes	Condition 19.2a through 19.2d, 24
AQ0075TVP04, Condition 20	Minor Permits AQ0075MSS02, Construction Permit AQ0075CPT02 , 18 AAC 50.040(j), 50.326(j), 40 C.F.R. 71.6(a)	Ambient Air Quality Protection	Do not exceed 300 hours of operation per 12 consecutive month period	Yes	Conditions 20.1 through 20.4, 23, 24

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0075TVP04, Condition 43	18 AAC 50.040(c)(23), (j), & 50.326(j) 40 CFR 71.6(a)(1) 40 CFR 63.6585 and 63.6590(c), Subpart ZZZZ	NESHAP Subpart ZZZZ Applicability	Comply with the applicable requirements of NESHAP Subpart ZZZZ	Yes	Condition 45

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	Not affected units (unless modified or reconstructed in the future). These emission units were manufactured prior to April 1, 2006 applicability date (see 40 C.F.R. 60.4200(a)(2(i)), and have not been modified or reconstructed after July 11, 2005 (see 40 C.F.R. 60.4200(a)(3)).
40 CFR Subpart ZZZZ §§63.6600, 63.6601, 63.6602, 63.6610, 63.6611	Requirements apply to affected units located at a major source. PS 4 is an area source of HAP emissions.
40 C.F.R. Subpart ZZZZ emission limitations and operating limitations under Table 2b referenced by §63.6603(a) §63.6604 §§63.6612, 63.6615, and 63.6620 §§63.6625(a)-(d), §63.6625(g) §63.6630 §§63.6640(b) & (e) §§63.6645(a) §§63.6645(b)-(h) §§63.6655(a) & (b) §63.6655(c)	Emergency CI RICE located at area sources are not subject to the numerical CO emissions limitations or the operating limitations related to oxidation catalysts in Table 2b. Emergency RICE are not subject to the fuel requirements under 63.6604 The performance test requirements and initial compliance demonstrations do not apply to emergency RICE not subject to numerical CO emission standards. Requirements apply to RICE using CEMS or CPMS to demonstrate compliance, to RICE burning landfill or digester gas, or to emergency RICE located at a major source of HAP emissions Emergency RICE are not subject to the crankcase control requirements under 63.6604. Does not apply because emergency RICE are not subject to numerical CO emission standards. Reporting requirements apply to RICE subject to an emission limitation or operating limitation. Per 63.6645(a)(5), notification requirements do not apply to emergency RICE. Notification requirements apply to RICE located at HAP major sources, or to RICE required to conduct a performance test or other initial compliance demonstration. These recordkeeping requirements only apply to RICE subject to an emission or operating limitation. These recordkeeping requirements only apply to RICE burning landfill or digester gas.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit Number: AQ0075TVP04

1.	Emission Unit ID Number // Operating Scenario	EU ID 22 // Operating Scenario 1
2.	Date installation/construction commenced[1]	2010
3.	Date installed	
4.	Emission Unit serial number	34-GEN-4401
5.	Special control requirements? [if yes, describe]	
6.	Manufacturer and model number	MTU Detroit 16V 2000G45TB
7.	Type of combustion device	Reciprocating internal combustion engine
8.	Rated design capacity (horsepower rating for engines)	
9.	Rated design capacity (heat input, MMBtu/hr rating for turbines)	
10.	If used for power generation, electrical output (kW)	800 kWe

1. See page 2 of the Form B instructions regarding installation/construction date and consult regulations under 40 C.F.R. 60 (NSPS) and 40 C.F.R. 63 (NESHAP) for applicability dates, e.g.,
- NSPS Subparts IIII and JJJJ, and NESHAP Subpart ZZZZ for engines, and
- NSPS Subparts GG and KKKK, and NESHAP Subpart YYYY for turbines.
Note that other regulations may apply in addition to the regulations cited.

11. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Diesel	52.25 gal/hr

12.	Describe any specific modifications to the emission unit that must be addressed in the permit:

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0075TVP04, Condition 1	18 AAC 50.040(j) 50.055(a)(1), & 50.326(j) 40 CFR 71.6(a)(1)	Visible Emissions Standard	20% average over any six consecutive minutes.	Yes	Conditions 1.1, 1.2, 2 through 4, Standard Permit Condition IX
AQ0075TVP04, Condition 5	18 AAC 50.040(j), 50.055(b)(1), & 50.326(j) 40 CFR 71.6(a)(1)	PM Emission Standards	Shall not exceed 0.05 grains per cu. ft. of exhaust corrected to standard conditions and averaged over three hours.	Yes	Conditions 5.1, 5.2, 6 through 8, Standard Permit Condition IX
AQ0075TVP04, Condition 13	18 AAC 50.040(j), 50.055(c), 50.326(j) 40 CFR 71.6(a)(1)	Sulfur Compound Emissions Standard	SO_2 not to exceed 500 ppm averaged over three hours.	Yes	Conditions 14, 19.2, Standard Permit Condition XI
AQ0075TVP04, Condition 19, 19.2	Permit No. AQ0075CPT02 40 C.F.R. 71.6(a)(3) & (c)(6)	Ambient Air Quality Protection Requirements Fuel Sulfur Limits	Comply with SO_2 ambient air quality standards by limiting the diesel fuel sulfur content to no greater than 0.20 percent by weight.	Yes	Condition 19.2a through 19.2d
AQ0075TVP04, Condition 23, 23.2	Permit No. AQ0075MSS03 18 AAC 50.040(j), 18 AAC 50.326(j) 40 C.F.R. 71.6(a) & (c)(6)	ORLs to Avoid Project Classification as a PSD Modification	Limit the hours of operation to no more than 200 hours per 12 consecutive month period.	Yes	Conditions 23.2a through 23.2e

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0075TVP04, Condition 36	18 AAC 50.040(j)(4), 50.326(j), 40 CFR 71.6(a)(1), 60.4200(a), Subpart IIII	NSPS Subpart IIII	Comply with the applicable requirements of NSPS Subpart IIII and Table 8 of Subpart IIII.	Yes	Conditions 36.1, 37 through 42
AQ0075TVP04, Condition 43	18 AAC 50.040(c)(23), (j), & 50.326(j) 40 CFR 71.6(a)(1) 40 CFR 63.6585 and 63.6590(c), Subpart ZZZZ	NESHAP Subpart ZZZZ Applicability	Comply with the applicable requirements of NESHAP Subpart ZZZZ.	Yes	Conditions 43.1, 44, 36 through 40

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

B.4 Form B4: Emission Unit Detail Form – Volatile Liquid Storage Tanks

FORM B4

Emission Unit Detail Form – Volatile Liquid Storage Tanks

Permit Number: AQ0075TVP04

1.	Emission Unit ID Number // Operating Scenario	EU ID 21 // Operating Scenario 1
2.	Date installation/construction commenced	Pre-1978
3.	Date installed	Pre-1978
4.	Special control requirements? [if yes, describe]	No
5.	Rated capacity (gallons)	2,310,000 gallons (55,000 bbls)
6.	Tank height (ft)	32
7.	Tank diameter (ft)	116
8.	Tank age (years)	34
9.	Submerged fill pipe?	Yes
10.	Type of tank (specify)	Fixed Roof
11.	Underground?	No
	If underground, specify type of tube and vapor return.	
12.	Above ground vapor control information:	
	Pipe material	
	Pipe size	
	Piping drainage (continuous drain downward or condensate collection tank – if condensate collection, attach a description)	
	Isolation valve installed in piping?	
13.	Pressure vacuum relief valves:	
	Vent pressure settings (psia)	0.006
	Months in which relief valves removed (specify)	N/A
14.	Pressure conservation vent? [if yes, specify pressure setting – psia]	
15.	Fixed roof tanks:	
	Roof color	White
	Shell color	Green
	Average vapor space height (ft)	22
	Shell condition (specify)	Good

	Emission Unit ID Number	21
16	Floating roof tanks:	
	Type of construction (specify)	
	Condition (specify)	
	Tank color	
	Deck type (specify)	
17.	External floating roof tanks, seal type (specify)	
18.	Internal floating roof tanks:	
	Seal type (specify)	
	Number of columns	
	Effective column diameter (ft)	
	Total deck seam length (ft)	
	Deck fitting types – access hatch	
	bolted cover, gasketed	
	unbolted cover, gasketed	
	unbolted cover, ungasketed	
	Deck fitting types - Automatic gauge float well	
	bolted cover, gasketed	
	unbolted cover, gasketed	
	unbolted cover, ungasketed	
	Deck fitting types – column well	
	Built up column – sliding cover, gasketed	
	Built up column – sliding cover, ungasketed	
	Pipe column – flexible fabric sleeve seal	
	Pipe column – – sliding cover, gasketed	
	Pipe column – – sliding cover, ungasketed	
	Deck fitting types – ladder well	
	sliding cover, gasketed	
	sliding cover, ungasketed	

	Emission Unit ID Number	21
	Deck fitting types – smple well or pipe	
	Slotted pipe – sliding cover, gasketed	
	Slotted pipe – sliding cover, ungasketed	
	Sample well – slit fabric seal, 10% open area	
	Stub drain – 1-inch diameter	
	Deck fitting type – roof leg or hanger will	
	Adjustable	
	fixed	
	Deck fitting type – vacuum breaker	
	Weighted mechanical actuation, gasketed	
	Weighted mechanical actuation, ungasketed	
19.	Maximum liquid loading rate (gal/hr)	1,000,000
20.	Submerged fill at out-loading (describe)	
21.	Material(s) stored	
	Type of material	Crude Oil
	Normal annual throughput (gal/yr)	Varies
	Normal turnovers per year	Varies
	Density (lbs/gal)	7
	Molecular weight	203
	Average storage temperature (°F)	57
	Vapor pressure (psi)	4.3

FORM B4

Emission Unit Detail Form – Volatile Liquid Storage Tanks

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0075TVP04, Condition 17	Preconstruction Permit No. AQ0075CPT03, 18 AAC 50.040(j), 50.326(j), 40 CFR 71.6(a)	Owner Requested Limit to Avoid Classification as a HAP Major	Limit HAP emissions to no more than 8.0 tons per 12-month rolling period for any individual HAP and 16.9 tons for the aggregate total of HAPs per 12-month rolling period.	Yes	Conditions 17.1 through 17.2

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B4

Emission Unit Detail Form – Volatile Liquid Storage Tanks

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 60 Subpart Ka - Standards of Performance for Storage Vessels for Petroleum Liquids	Commenced construction prior to effective date of subpart (May 18, 1978). The tank has not been modified or reconstructed since the effective date of the standard. The tank is a crude oil breakout tank (not storage vessels as defined in 40 CFR 60) and part of a pipeline system as defined by 49 CFR 195.2.
40 CFR 60 Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels)	Commenced construction prior to effective date of subpart (July 23, 1984). The tanks have not been modified or reconstructed since the effective date of the standard. The tanks are crude oil breakout tanks (not storage vessels as defined in 40 CFR 60) and part of a pipeline system as defined by 49 CFR 195.2.
40 C. F. R. 60 Subpart Kc—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels)	Commenced construction prior to effective date of subpart (October 23, 2023). The tank has not been modified or reconstructed since the effective date of the standard.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Appendix C Pollution Control Devices – *Not Applicable*

Application for Renewal of an Air Quality Operating Permit

Pump Station 4

Alyeska Pipeline Service Company

SLR Project No.: 105.021406.00001

July 25, 2025

Appendix D Emissions Summary

Application for Renewal of an Air Quality Operating Permit

Pump Station 4

Alyeska Pipeline Service Company

SLR Project No.: 105.021406.00001

July 25, 2025

D.1 Form D1: Potential to Emit (after controls/limitations) Emissions

Table D1-1. Potential Annual Emissions (after controls/limitations) Summary
Alyeska Pipeline Services Company - Pump Station 4

Potential to Emit	Regulated Air Pollutant Emissions (tons per year) [1,2]							
	NO_X	CO	PM_{10}	$PM_{2.5}$ [3]	VOC	SO_2	HAP [4]	GHG [5]
Significant	172.3	1,057.3	9.7	9.7	24.0	16.6	1.8	148,660
Insignificant	6.0	3.6	0.7	0.7	0.2	4.2	0.7	6,958
Assessable Emission Subtotals	**178**	**1,061**	**10**	**10**	**24.2**	**21**	**3**	**155,619**
Fees Apply to Pollutant?	**Yes**	**Yes**	**Yes**	**No**	**Yes**	**Yes**	**No** [6]	**No** [7]
Total Assessable Emissions	**1,295**							

Notes:
[1] Emissions are based on maximum allowable operation and permit operating limits, where applicable.
[2] Regulated air pollutant calculations based on AP-42 emission factors, manufacturer data, and mass balances as shown in accompanying spreadsheets.
[3] $PM_{2.5}$ is a subset of PM_{10} emissions and is excluded from total to avoid a double payment.
[4] See individual emissions unit category HAP emissions calculations for details on methodology and assumptions (electronic copy).
[5] GHG emissions are defined as CO_2e emissions. CO_2e is the summation of CO_2, CH_4, and N_2O, applying the global warming potential for each pollutant.
[6] HAP emissions are a subset of either VOC emissions or PM_{10} emissions and are excluded from the assessable emissions total to avoid a double payment.
[7] Assessable emission fees for GHGs have not been established under 18 AAC 50.

Table D1-2a. Significant Emissions Unit Inventory
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit				Fuel Type	Maximum Operation
ID	Description	Make / Model	Rating		
8	Heater	Eclipse Therminol	20.6 MMBtu/hr	Natural Gas	8,260 hours
				Diesel	500 hours [1]
9	Heater	Eclipse Therminol	20.6 MMBtu/hr	Natural Gas	8,260 hours
				Diesel	500 hours [1]
12	Cyclone Turbine	Siemens / SGT-400	12.9 MW	Natural Gas	8,520 hours
				Diesel	240 hours [2]
13	Cyclone Turbine	Siemens / SGT-400	12.9 MW	Natural Gas	8,760 hours
14	Generator Engine	Caterpillar / 3516B	2,250 kW	Diesel	600 hours [2]
15	Generator Engine	John Deere	65 kW	Diesel	300 hours [2]
21	Breakout Tank 140	Crude Oil Storage Tank	55,000 bbl	N/A	8,760 hours
22	Generator Engine	Detroit Diesel / 2000G45TB	800 kWe	Diesel	200 hours [3]

Notes:
[1] Title V Permit AQ0075TVP04 Condition 16 limits the annual operation of EU ID 8 and 9 to a maximum 1,000 hours, combined, of diesel.
[2] Title V Permit AQ0075TVP04 Condition 20 limits the annual operation of EU ID 12 to a maximum 240 hours on diesel, EU ID 14 to a maximum 600 hours and EU ID 15 to a maximum of 300 hours.
[3] Title V Permit AQ0075TVP04 Condition 23.2 limits the annual operation of EU ID 22 to a maximum 200 hours.

Table D1-2b. Insignificant Emissions Unit Inventory
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit(s)			Fuel / Material Type	Maximum Operation	Rating	Basis for Insignificance
ID	Description	Make / Model				
N/A	Heater	Burnham	Natural Gas	8,760 hours	0.763 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Burnham	Natural Gas	8,760 hours	0.763 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Ground	Diesel	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(7)
N/A	Heater	Tioga	Diesel	8,760 hours	0.600 MMBtu/hr	18 AAC 50.326(g)(7)
N/A	Heater	Tioga	Diesel	8,760 hours	0.600 MMBtu/hr	18 AAC 50.326(g)(7)
N/A	Heater	Chinook	Diesel	8,760 hours	0.800 MMBtu/hr	18 AAC 50.326(g)(7)
N/A	Heater	Chinook	Diesel	8,760 hours	0.800 MMBtu/hr	18 AAC 50.326(g)(7)
N/A	Heater	Aerotec	Diesel	8,760 hours	0.400 MMBtu/hr	18 AAC 50.326(g)(7)

Table D1-3. Potential Annual Emissions (after controls/limitations) Calculations - Oxides of Nitrogen (NO_X)
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel	Factor	NO_X Emission	Potential	Potential
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	NO_X Emissions [1]
Significant Emissions Units							
8	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,260 hours	8.3 tpy
			Diesel	AP-42 Table 1.3-1	20 lb/Mgal	500 hours	0.7 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,260 hours	8.3 tpy
			Diesel	AP-42 Table 1.3-1	20 lb/Mgal	500 hours	0.7 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	Manufacturer's Data	Load based	8,520 hours	65.8 tpy [2]
			Diesel			240 hours	
13	Cyclone Turbine	12.9 MW	Natural Gas	Manufacturer's Data	Load based	8,760 hours	65.8 tpy [2]
14	Generator Engine	2,250 kW	Diesel	Manufacturer's Data	71 lb/hr	600 hours	21.3 tpy
15	Generator Engine	65 kW	Diesel	Tier 2 Standard [3]	7.5 g/kW-hr	300 hours	0.2 tpy
21	Breakout Tank 140	55,000 bbl	N/A	N/A	N/A	8,760 hours	0 tpy
22	Generator Engine	800 kWe	Diesel	Manufacturer's Data	11.0 lb/hr	200 hours	1.1 tpy
						Significant Emissions Units Emissions - NO_X	**172.3 tpy**
Insignificant Emissions Units							
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.3 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.3 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	AP-42 Table 1.3-1	20 lb/Mgal	8,760 hours	0.3 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-1	20 lb/Mgal	8,760 hours	0.4 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-1	20 lb/Mgal	8,760 hours	0.4 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-1	20 lb/Mgal	8,760 hours	0.5 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-1	20 lb/Mgal	8,760 hours	0.5 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	AP-42 Table 1.3-1	20 lb/Mgal	8,760 hours	0.3 tpy
						Insignificant Emissions Units Emissions - NO_X	**6.0 tpy**
						Total Emissions - NO_X	**178.3 tpy**

Notes:

[1] Parameters and conversions:

Natural Gas High Heat Value: AP-42 Table 1.4-1	1,020	Btu/scf
Diesel High Heat Value: AP-42 Table 1.3-1	139	MMBtu/10^3 gal
Average BSFC, Table 3.4-1, AP-42	7,000	Btu/hp-hr

[2] Load based. Emissions for EU ID 12 and 13 based on AQ0075MSS03 TAR, Table 1.

[3] 40 CFR Appendix I to Part 1039(b)

Table D1-4. Potential Annual Emissions (after controls/limitations) Calculations - Carbon Monoxide (CO)
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel	Factor	CO Emission	Potential	Potential
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	CO Emissions [1]
Significant Emissions Units							
8	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,260 hours	7.0 tpy
			Diesel	AP-42 Table 1.3-1	5 lb/Mgal	500 hours	0.19 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,260 hours	7.0 tpy
			Diesel	AP-42 Table 1.3-1	5 lb/Mgal	500 hours	0.19 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	Manufacturer's Data	Load based	8,520 hours	521.0 tpy [2]
			Diesel			240 hours	
13	Cyclone Turbine	12.9 MW	Natural Gas	Manufacturer's Data	Load based	8,760 hours	521.0 tpy [2]
14	Generator Engine	2,250 kW	Diesel	Manufacturer's Data	2 lb/hr	600 hours	0.66 tpy
15	Generator Engine	65 kW	Diesel	Tier 2 Standard [3]	5.0 g/kW-hr	300 hours	0.11 tpy
21	Breakout Tank 140	55,000 bbl	N/A	N/A	N/A	8,760 hours	0 tpy
22	Generator Engine	800 kWe	Diesel	Manufacturer's Data	1.1 lb/hr	200 hours	0.11 tpy
						Significant Emissions Units Emissions - CO	**1,057.3 tpy**
Insignificant Emissions Units							
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.3 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.3 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	AP-42 Table 1.3-1	5 lb/Mgal	8,760 hours	0.1 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-1	5 lb/Mgal	8,760 hours	0.1 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-1	5 lb/Mgal	8,760 hours	0.1 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-1	5 lb/Mgal	8,760 hours	0.1 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-1	5 lb/Mgal	8,760 hours	0.1 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	AP-42 Table 1.3-1	5 lb/Mgal	8,760 hours	0.06 tpy
						Insignificant Emissions Units Emissions - CO	**3.6 tpy**
						Total Emissions - CO	**1,060.9 tpy**

Notes:

[1] Parameters and conversions:

Natural Gas High Heat Value: AP-42 Table 1.4-1	1,020	Btu/scf
Diesel High Heat Value: AP-42 Table 1.3-1	139	MMBtu/10^3 gal
Average BSFC, Table 3.4-1, AP-42	7,000	Btu/hp-hr

[2] Load based. Emissions for EU ID 12 and 13 based on AQ0075MSS03 TAR, Table 1.

[3] 40 CFR Appendix I to Part 1039(b)

Table D1-5. Potential Annual Emissions (after controls/limitations) Calculations - Particulate Matter Less Than 10 Microns (PM_{10})
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel	Factor	PM_{10} Emission	Potential	Potential
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	PM_{10} Emissions [1]
Significant Emissions Units							
8	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,260 hours	0.2 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.5 tpy
			Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	500 hours	0.1 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0.0 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,260 hours	0.2 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.5 tpy
			Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	500 hours	0.07 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0.05 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	Manufacturer's Data	Load based	8,520 hours	4.0 tpy [2]
			Diesel			240 hours	
13	Cyclone Turbine	12.9 MW	Natural Gas	Manufacturer's Data	Load based	8,760 hours	4.0 tpy [2]
14	Generator Engine	2,250 kW	Diesel	Manufacturer's Data	0.6 lb/hr	600 hours	0.2 tpy
15	Generator Engine	65 kW	Diesel	AP-42 Table 3.3-1	3.1E-01 lb/MMBtu	300 hours	0.03 tpy
21	Breakout Tank 140	55,000 bbl	N/A	N/A	N/A	8,760 hours	0 tpy
22	Generator Engine	800 kWe	Diesel	Manufacturer's Data	0.09 lb/hr	200 hours	0.01 tpy
						Significant Emissions Units Emissions - PM_{10}	**9.7 tpy**
Insignificant Emissions Units							
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8760 hours	0.006 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.02 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8760 hours	0.006 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.02 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	8,760 hours	0.03 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0.02 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	8,760 hours	0.04 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0.02 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	8,760 hours	0.04 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0.02 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	8,760 hours	0.05 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0.03 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	8,760 hours	0.05 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0.03 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	8,760 hours	0.03 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0.02 tpy
						Insignificant Emissions Units Emissions - PM_{10}	**0.7 tpy**
						Total PM_{10} Emissions	**10.4 tpy**

Notes:
[1] Parameters and conversions:

Natural Gas High Heat Value: AP-42 Table 1.4-1, 3.1-1	1,020	Btu/scf
Diesel High Heat Value: AP-42 Table 1.3-1	139	$MMBtu/10^3$ gal
Average BSFC, Table 3.4-1, AP-42	7,000	Btu/hp-hr
F Factor HHV, EPA Method 19 (Natural Gas)	8,710	dcf/MMBtu

[2] Load based. Emissions for EU ID 12 and 13 based on AQ0075MSS03 TAR, Table 1.

Table D1-6a. Potential Annual Emissions (after controls/limitations) Calculations - Volatile Organic Compounds (VOC)
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel	Factor	VOC Emission	Potential	Potential
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	VOC Emissions [1]
Significant Emissions Units							
8	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,260 hours	0.5 tpy
			Diesel	AP-42 Table 1.3-3	0.252 lb/Mgal	500 hours	0.01 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,260 hours	0.5 tpy
			Diesel	AP-42 Table 1.3-3	0.252 lb/Mgal	500 hours	0.01 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	Manufacturer's Data	Load based	8,520 hours	1.3 tpy [2]
			Diesel			240 hours	
13	Cyclone Turbine	12.9 MW	Natural Gas	Manufacturer's Data	Load based	8,760 hours	1.3 tpy [2]
14	Generator Engine	2,250 kW	Diesel	Manufacturer's Data	1 lb/hr	600 hours	0.30 tpy
15	Generator Engine	65 kW	Diesel	AP-42 Table 3.3-1	2.47E-03 lb/hp-hr	300 hours	0.03 tpy
21	Breakout Tank 140	55,000 bbl	N/A	N/A	N/A	8,760 hours	20.1 tpy
22	Generator Engine	800 kWe	Diesel	Manufacturer's Data	0.3 lb/hr	200 hours	0.03 tpy
						Significant Emissions Units Emissions - VOC	**24.0 tpy**
Insignificant Emissions Units							
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.02 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.02 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	AP-42 Table 1.3-1	0.252 lb/Mgal	8,760 hours	0.004 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-1	0.252 lb/Mgal	8,760 hours	0.005 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-1	0.252 lb/Mgal	8,760 hours	0.005 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-1	0.252 lb/Mgal	8,760 hours	0.006 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-1	0.252 lb/Mgal	8,760 hours	0.006 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	AP-42 Table 1.3-1	0.252 lb/Mgal	8,760 hours	0.003 tpy
						Insignificant Emissions Units Emissions - VOC	**0.2 tpy**
						Total Emissions - VOC	**24.2 tpy**

Notes:
[1] Parameters and conversions:

Natural Gas High Heat Value: AP-42 Table 1.4-1, 3.1-1	1,020 Btu/scf
Diesel High Heat Value: AP-42 Table 1.3-1	139 MMBtu/10^3 gal
Average BSFC, Table 3.4-1, AP-42	7,000 Btu/hp-hr

[2] Load based. Emissions for EU ID 12 and 13 based on AQ0075MSS03 TAR, Table 1.

Table D1-6b. Potential Annual Emissions (after controls/limitations) Calculations - Tank Emissions
Alyeska Pipeline Services Company - Pump Station 4

Tank Description	Breakout Tank 140
Orientation	Vertical
Contents	Crude Oil
Capacity (gallons)	2,310,000
Diameter, D (ft)	116
Radium, R_S (ft)	58
Shell Height, H_S (ft)	32
Average Liquid Height (H_L)	28.0
Maximum Liquid Height (H_{LX})	31
Crude Throughput, Q (bbl/yr)	55,000
Color	White
Paint Condition	Average
Roof Type	Cone
Slope, S_R (ft/ft)	0.125
Standing Loss (L_S) Calculations	
Vapor Space Expansion Factor, K_E	0.016
Vapor Space Outage, H_{VO} (ft)	6.42
Average Daily Ambient Temperature, T_{AA} (^oR)	471.70
Liquid Bulk Temperature, T_B (^oR)	471.71
Average Daily Liquid Surface Temperature, T_{LA} (^oR)	471.73
Average Vapor Temperature, T_V (^oR)	471.75
Vented Vapor Density, K_S	0.166
Stock Vapor Density, W_V (lb/ft^3)	0.145
Standing Loss, L_S (lb/yr)	**9,763**
Working Loss (L_W) Calculations	
Tank Maximum Liquid Volume, V_{LX} (ft^3)	327,617.85
Number of Turnovers per Year, N	1.0
Turnover Factor, K_N	1.0
Working Loss, L_W (lb/yr)	**30,360**
Total VOCs (tpy)	**20.1**

Meteorological Inputs (Prudhoe Bay, AK):

T_{AX} =	18.1 F	478.1 R	Source: Western Regional Climate Center
T_{AN} =	5.3 F	465.3 R	Source: Western Regional Climate Center
a =	0.25	White, Average	
I =	18.5	Btu/ft^2-d	

Constants:

K_P (crude)=	0.75	
M_V (crude)=	50	lb/lb-mol
P_{va} (crude)=	14.72	psi

Table D1-7. Potential Annual Emissions (after controls/limitations) Calculations - Sulfur Dioxide (SO_2)
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel	Factor	Maximum Fuel	SO_2 Emission	Potential	Potential
ID	Description	Rating/Capacity	Type	Reference	Sulfur Content [1,2]	Factor [3]	Operation	SO_2 Emissions [3,4]
Significant Emissions Units								
8	Heater	20.6 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,260 hours	2.1 tpy
			Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	500 hours	1.1 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,260 hours	2.1 tpy
			Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	500 hours	1.1 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	Mass Balance	150 ppmv H_2S	Load based	8,520 hours	4.5 tpy [5]
			Diesel		0.2 wt.% S		240 hours	
13	Cyclone Turbine	12.9 MW	Natural Gas	Mass Balance	150 ppmv H_2S	Load based	8,760 hours	4.5 tpy [5]
14	Generator Engine	2,250 kW	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	600 hours	1.3 tpy
15	Generator Engine	65 kW	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	300 hours	0.02 tpy
21	Breakout Tank 140	55,000 bbl	N/A	N/A	N/A	N/A	8,760 hours	0 tpy
22	Generator Engine	800 kWe	Diesel	Manufacturer's Data	0.0015 wt.% S	2.13E-04 lb/gal	200 hours	0.001 tpy
							Significant Emissions Units Emissions - SO_2	**16.6 tpy**
Insignificant Emissions Units								
N/A	Heater	0.763 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.08 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.08 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8,760 hours	0.4 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8,760 hours	0.5 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8,760 hours	0.5 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8,760 hours	0.7 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8,760 hours	0.7 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8,760 hours	0.4 tpy
							Insignificant Emissions Units Emissions - SO_2	**4.2 tpy**
							Total Emissions - SO_2	**20.9 tpy**

Notes:
[1] Per AQ0074TVP04 Condition 19.1 - Limit H_2S concentration of fuel gas to no greater than 150 ppmv
[2] Per AQ0074TVP04 Condition 19.2 - Limit fuel sulfur concentration of diesel fuel to no greater than 0.20 percent by weight
[3] Density of diesel fuel. 7.10 lb/gal
[4] Parameters and conversions:
Natural Gas High Heat Value: AP-42 Table 1.4-2, 3.1-2a 1,020 Btu/scf
Diesel average heat value: Table 3.1-2a, AP-42. 139 MMBtu/10^3 gallons
Average BSFC, Table 3.4-1, AP-42 7,000 Btu/hp-hr
[5] Load based. Emissions for EU ID 12 and 13 based on AQ0075MSS03 TAR, Table 1.

Table D1-8. Potential Annual Emissions (after controls/limitations) Calculations - Hazardous Air Pollutants (HAP) Summary
Alyeska Pipeline Services Company - Pump Station 4

Hazardous Air Pollutant	Natural Gas Fired Heaters	Diesel Heaters	Natural Gas Fired Turbines	Diesel Fired Turbines	Liquid Fugitives	Gas Fugitives	Diesel Engines <600 hp	Diesel Engines >600 hp	Insignificant Units NG [2]	Insignificant Units Diesel [2]	Total HAP Emissions
Acetaldehyde	----	----	4.18E-02	----	----	----	7.02E-05	1.60E-04	----	----	4.21E-02
Acrolein	----	----	6.70E-03	----	----	----	8.47E-06	4.99E-05	----	----	6.75E-03
Benzene	3.50E-04	2.16E-03	1.26E-02	7.99E-04	1.49E-01	1.72E-02	8.54E-05	4.92E-03	7.60E-05	3.40E-03	1.90E-01
1,3 Butadiene	----	----	4.50E-04	2.32E-04	0.00E+00	0.00E+00	----	----	----	----	6.82E-04
Dichlorobenzene	2.00E-04	----	----	----	----	----	----	----	4.34E-05	----	2.44E-04
Ethyl benzene	----	6.55E-04	3.35E-02	----	9.00E-02	0.00E+00	----	----	----	1.03E-03	1.25E-01
Formaldehyde	1.25E-02	3.40E-01	7.43E-01	4.07E-03	----	----	1.08E-04	5.00E-04	2.71E-03	5.35E-01	1.64E+00
Hexane	3.00E-01	----	----	----	----	----	----	----	6.51E-02	----	3.65E-01
Polycyclic aromatic compounds(PAH)	1.13E-04	1.49E-02	2.30E-03	5.81E-04	----	----	1.54E-05	1.34E-03	2.44E-05	2.34E-02	4.26E-02
Polycyclic Organic Matter (POM)	1.13E-04	1.49E-02	----	----	----	----	1.54E-05	1.34E-03	2.44E-05	2.34E-02	3.97E-02
Acenaphthene	3.00E-07	2.17E-04	----	----	----	----	1.30E-07	2.97E-05	6.51E-08	3.42E-04	5.89E-04
Acenaphthylene	3.00E-07	2.61E-03	----	----	----	----	4.63E-07	5.85E-05	6.51E-08	4.10E-03	6.77E-03
Anthracene	4.00E-07	1.26E-05	----	----	----	----	1.71E-07	7.79E-06	8.68E-08	1.98E-05	4.08E-05
Benzo(a)anthracene	----	4.13E-05	----	----	----	----	1.54E-07	3.94E-06	----	6.50E-05	1.10E-04
Benzo(a)pyrene	2.00E-07	----	----	----	----	----	1.72E-08	1.63E-06	4.34E-08	----	1.89E-06
Benzo(b)fluoranthene	3.00E-07	----	----	----	----	----	9.07E-09	7.03E-06	6.51E-08	----	7.41E-06
Benzo(g,h,i)perylene	2.00E-07	2.33E-05	----	----	----	----	----	----	4.34E-08	----	2.35E-05
Benzo(g,h,l)perylene	----	----	----	----	----	----	4.48E-08	3.52E-06	----	----	3.57E-06
Benzo(k)fluoranthene	3.00E-07	----	----	----	----	----	1.42E-08	1.38E-06	6.51E-08	----	1.76E-06
Chrysene	3.00E-07	2.45E-05	----	----	----	----	3.23E-08	9.69E-06	6.51E-08	----	3.46E-05
Dibenz(a,h)anthracene	----	1.72E-05	----	----	----	----	5.34E-08	2.19E-06	----	----	1.94E-05
7,12-Dimethylbenz(a)anthracene	2.67E-06	----	----	----	----	----	----	----	5.79E-07	----	3.25E-06
Fluoranthene	5.00E-07	4.99E-05	----	----	----	----	6.96E-07	2.55E-05	1.09E-07	----	7.67E-05
Fluorene	4.67E-07	4.60E-05	----	----	----	----	2.67E-06	8.11E-05	1.01E-07	----	1.30E-04
Indeno(1,2,3-cd)pyrene	3.00E-07	2.20E-05	----	----	----	----	3.43E-08	2.62E-06	6.51E-08	----	2.51E-05
2-Methylnapthalene	4.00E-06	----	----	----	----	----	----	----	8.68E-07	----	4.87E-06
3-Methylcholanthrene	3.00E-07	----	----	----	----	----	----	----	6.51E-08	----	3.65E-07
Naphthalene	1.02E-04	1.16E-02	----	----	7.20E-02	----	7.76E-06	8.24E-04	2.21E-05	----	8.46E-02
Phenanthrene	----	1.08E-04	----	----	----	----	2.69E-06	2.59E-04	----	----	3.69E-04
Pyrene	8.34E-07	4.38E-05	----	----	----	----	4.37E-07	2.35E-05	----	----	6.86E-05
CDD (Dioxin Compounds)	----	----	----	----	----	----	----	----	----	----	0.00E+00
1,3-Propane sultone	----	----	----	----	----	----	----	----	----	----	0.00E+00
beta-Propiolactone	----	----	----	----	----	----	----	----	----	----	0.00E+00
Propionaldehyde	----	----	----	----	----	----	----	----	----	----	0.00E+00
Propoxur (Baygon)	----	----	----	----	----	----	----	----	----	----	0.00E+00
Propylene dichloride (1,2-Dichloropropane)	----	----	----	----	----	----	----	----	----	----	0.00E+00
Propylene Oxide	----	----	3.03E-02	----	----	----	----	----	----	----	3.03E-02
1,2-Propylenimine (2-Methyl aziridine)	----	----	----	----	----	----	----	----	----	----	0.00E+00
Quinoline	----	----	----	----	----	----	----	----	----	----	0.00E+00
Quinone	----	----	----	----	----	----	----	----	----	----	0.00E+00
Styrene	----	----	----	----	----	----	----	----	----	----	0.00E+00
Styrene oxide	----	----	----	----	----	----	----	----	----	----	0.00E+00
2,3,7,8-Tetrachlorodibenzo-p-dioxin	----	----	----	----	----	----	----	----	----	----	0.00E+00
1,1,2,2-Tetrachloroethane	----	----	----	----	----	----	----	----	----	----	0.00E+00
Tetrachloroethylene (Perchloroethylene)	----	----	----	----	----	----	----	----	----	----	0.00E+00
Titanium tetrachloride	----	----	----	----	----	----	----	----	----	----	0.00E+00
Toluene	5.67E-04	6.39E-02	1.36E-01	----	3.78E-01	1.01E-01	3.74E-05	1.78E-03	----	1.00E-01	7.82E-01
2,4-Toluene diamine	----	----	----	----	----	----	----	----	----	----	0.00E+00
2,4-Toluene diisocyanate	----	----	----	----	----	----	----	----	----	----	0.00E+00
o-Toluidine	----	----	----	----	----	----	----	----	----	----	0.00E+00
Toxaphene (chlorinated camphene)	----	----	----	----	----	----	----	----	----	----	0.00E+00
1,2,4-Trichlorobenzene	----	----	----	----	----	----	----	----	----	----	0.00E+00
1,1,2-Trichloroethane	----	----	----	----	----	----	----	----	----	----	0.00E+00
Trichloroethylene	----	----	----	----	----	----	----	----	----	----	0.00E+00
2,4,5-Trichlorophenol	----	----	----	----	----	----	----	----	----	----	0.00E+00
2,4,6-Trichlorophenol	----	----	----	----	----	----	----	----	----	----	0.00E+00
Triethylamine	----	----	----	----	----	----	----	----	----	----	0.00E+00
Trifluralin	----	----	----	----	----	----	----	----	----	----	0.00E+00
2,2,4-Trimethylpentane	----	----	----	----	----	----	----	----	----	----	0.00E+00
Vinyl acetate	----	----	----	----	----	----	----	----	----	----	0.00E+00
Vinyl bromide	----	----	----	----	----	----	----	----	----	----	0.00E+00
Vinyl chloride	----	----	----	----	----	----	----	----	----	----	0.00E+00
Vinylidene chloride (1,1-Dichloroethylene)	----	----	----	----	----	----	----	----	----	----	0.00E+00
Xylenes (isomers and mixture)	----	----	6.70E-02	----	----	----	2.61E-05	1.22E-03	----	----	6.82E-02
Arsenic	3.34E-05	----	----	1.60E-04	----	----	----	----	----	----	1.93E-04
Beryllium	2.00E-06	----	----	4.50E-06	----	----	----	----	----	----	6.51E-06
Cadmium	1.84E-04	----	----	6.97E-05	----	----	----	----	----	----	2.53E-04
Chromium	2.34E-04	----	----	1.60E-04	----	----	----	----	----	----	3.93E-04
Cobalt	1.40E-05	----	----	----	----	----	----	----	----	----	1.40E-05
Lead	----	----	----	2.03E-04	----	----	----	----	----	----	2.03E-04
Manganese	6.34E-05	----	----	1.15E-02	----	----	----	----	----	----	1.15E-02
Mercury	4.34E-05	----	----	1.74E-05	----	----	----	----	----	----	6.08E-05
Nickel	3.50E-04	----	----	6.68E-05	----	----	----	----	----	----	4.17E-04
Selenium	4.00E-06	----	----	3.63E-04	----	----	----	----	----	----	3.67E-04
Total HAPs - Maximum Individual HAP	**3.00E-01**	**3.40E-01**	**7.43E-01**	**1.15E-02**	**3.78E-01**	**1.01E-01**	**1.08E-04**	**4.92E-03**	**6.51E-02**	**5.35E-01**	**1.64E+00**
Total VOC HAP Emissions	**3.14E-01**	**4.21E-01**	**1.07E+00**	**5.68E-03**	**6.17E-01**	**1.18E-01**	**3.51E-04**	**9.97E-03**	**6.80E-02**	**6.63E-01**	**3.33E+00**
Total HAPs Emissions	**3.15E-01**	**4.21E-01**	**1.07E+00**	**1.82E-02**	**6.17E-01**	**1.18E-01**	**3.51E-04**	**9.97E-03**	**6.80E-02**	**6.63E-01**	**3.34E+00**

Notes:

[1] HAP emissions from the fuel storage tanks are considered negligible.
[2] The HAP emissions from insignificant natural gas heaters are included under Table D1-17 IEU NG Heaters and D1-18 IEU Diesel Heaters.

Table D1-9. Potential Annual Emissions (after controls/limitations) Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Natural Gas Fired Heaters

340,312 MMBtu/yr [1]

CAS No.	Chemical Name	AP-42 Emission Factor [2]		Estimated Emissions [3]	
		Source Category Emission Calculations			
91-57-6	2-Methylnapthalene	2.40E-05	lb/MMscf	4.00E-06	tpy
56-49-5	3-Methylcholanthrene	1.80E-06	lb/MMscf	3.00E-07	tpy
	7,12-Dimethylbenz(a)anthracene	1.60E-05	lb/MMscf	2.67E-06	tpy
83-32-9	Acenaphthene	1.80E-06	lb/MMscf	3.00E-07	tpy
203-96-8	Acenaphthylene	1.80E-06	lb/MMscf	3.00E-07	tpy
120-12-7	Anthracene	2.40E-06	lb/MMscf	4.00E-07	tpy
56-55-3	Benz(a)anthracene	1.80E-06	lb/MMscf	3.00E-07	tpy
71-43-2	Benzene	2.10E-03	lb/MMscf	3.50E-04	tpy
50-32-8	Benzo(a)pyrene	1.20E-06	lb/MMscf	2.00E-07	tpy
205-99-2	Benzo(b)fluoranthene	1.80E-06	lb/MMscf	3.00E-07	tpy
191-24-2	Benzo(g,h,i)perylene	1.20E-06	lb/MMscf	2.00E-07	tpy
207-08-9	Benzo(k)fluoranthene	1.80E-06	lb/MMscf	3.00E-07	tpy
218-01-9	Chrysene	1.80E-06	lb/MMscf	3.00E-07	tpy
53-70-3	Dibenzo(a,h)anthracene	1.20E-06	lb/MMscf	2.00E-07	tpy
25321-22-6	Dichlorobenzene	1.20E-03	lb/MMscf	2.00E-04	tpy
206-44-0	Fluoranthene	3.00E-06	lb/MMscf	5.00E-07	tpy
86-73-7	Fluorene	2.80E-06	lb/MMscf	4.67E-07	tpy
50-00-0	Formaldehyde	7.50E-02	lb/MMscf	1.25E-02	tpy
110-54-3	Hexane	1.80E+00	lb/MMscf	3.00E-01	tpy
193-39-5	Indeno(1,2,3-cd)pyrene	1.80E-06	lb/MMscf	3.00E-07	tpy
91-20-3	Naphthalene	6.10E-04	lb/MMscf	1.02E-04	tpy
85-01-8	Phenanathrene	1.70E-05	lb/MMscf	2.84E-06	tpy
74-98-6	Propane	1.60E+00	lb/MMscf	2.67E-01	tpy
129-00-0	Pyrene	5.00E-06	lb/MMscf	8.34E-07	tpy
108-88-3	Toluene	3.40E-03	lb/MMscf	5.67E-04	tpy
7440-38-2	Arsenic	2.00E-04	lb/MMscf	3.34E-05	tpy
7440-41-7	Beryllium	1.20E-05	lb/MMscf	2.00E-06	tpy
7440-43-9	Cadmium	1.10E-03	lb/MMscf	1.84E-04	tpy
7440-47-3	Chromium	1.40E-03	lb/MMscf	2.34E-04	tpy
7440-48-4	Cobalt	8.40E-05	lb/MMscf	1.40E-05	tpy
7439-96-5	Manganese	3.80E-04	lb/MMscf	6.34E-05	tpy
7439-97-6	Mercury	2.60E-04	lb/MMscf	4.34E-05	tpy
7440-02-0	Nickel	2.10E-03	lb/MMscf	3.50E-04	tpy
7782-49-2	Selenium	2.40E-05	lb/MMscf	4.00E-06	tpy
	Total Potential HAP Emissions:			**5.82E-01**	**tpy**

Notes:
[1] Total fuel use based on maximum full-time operation or permit-limited operation as noted below.

EU ID 8	Heater	20.6	MMBtu/hr
		8,260	hr/yr
	Potential Heat Input:	170,156	MMBtu/yr
EU ID 9	Heater	20.6	MMBtu/hr
		8,260	hr/yr
	Potential Heat Input:	170,156	MMBtu/yr
	Total Potential Heat Input:	**340,312**	**MMBtu/yr**

[2] Reference: AP-42, Tables 1.4-3 and 1.4-4.
[3] Natural Gas High Heat Value: AP-42 Table 1.4-2 1,020 Btu/scf

Table D1-10. Potential Annual Emissions (after controls/limitations) Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Diesel Fired Heaters

Potential Total Heat Input for Emissions Units: 20,600 MMBtu/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**Emission Factor [2]**	**Estimated Emissions [3]**
N/A	Arsenic Compounds	4.00E-06 lb/MMBtu	4.12E-05 tpy
71-43-2	Benzene	2.10E-04 lb/MMBtu	2.16E-03 tpy
N/A	Beryllium Compounds	3.00E-06 lb/MMBtu	3.09E-05 tpy
N/A	Cadmium Compounds	3.00E-06 lb/MMBtu	3.09E-05 tpy
N/A	Chromium Compounds	3.00E-06 lb/MMBtu	3.09E-05 tpy
100-41-4	Ethyl benzene	6.36E-05 lb/MMBtu	6.55E-04 tpy
50-00-0	Formaldehyde	3.30E-02 lb/MMBtu	3.40E-01 tpy
N/A	Lead Compounds	9.00E-06 lb/MMBtu	9.27E-05 tpy
N/A	Manganese Compounds	6.00E-06 lb/MMBtu	6.18E-05 tpy
N/A	Mercury Compounds	3.00E-06 lb/MMBtu	3.09E-05 tpy
N/A	Nickel Compounds	3.00E-06 lb/MMBtu	3.09E-05 tpy
N/A	Selenium Compounds	1.50E-05 lb/MMBtu	1.55E-04 tpy
108-88-3	Toluene	6.20E-03 lb/MMBtu	6.39E-02 tpy
71-55-6	1,1,1-Trichloroethane	2.36E-04 lb/MMBtu	2.43E-03 tpy
1330-20-7	Xylenes	1.09E-04 lb/MMBtu	1.12E-03 tpy
N/A	Polycyclic Organic Matter (POM)		1.49E-02 tpy
N/A	Polycyclic aromatic compounds(PAH)		1.49E-02 tpy
208-96-8	Acenaphthene	2.11E-05 lb/MMBtu	2.17E-04 tpy
83-32-9	Acenaphthylene	2.53E-04 lb/MMBtu	2.61E-03 tpy
120-12-7	Anthracene	1.22E-06 lb/MMBtu	1.26E-05 tpy
56-55-3	Benzo(a)anthracene	4.01E-06 lb/MMBtu	4.13E-05 tpy
205-99-2	Benzo(b,k)fluoranthene	1.48E-06 lb/MMBtu	1.52E-05 tpy
191-24-2	Benzo(g,h,i)perylene	2.26E-06 lb/MMBtu	2.33E-05 tpy
218-01-9	Chrysene	2.38E-06 lb/MMBtu	2.45E-05 tpy
53-70-3	Dibenz(a,h)anthracene	1.67E-06 lb/MMBtu	1.72E-05 tpy
206-44-0	Fluoranthene	4.84E-06 lb/MMBtu	4.99E-05 tpy
86-73-7	Fluorene	4.47E-06 lb/MMBtu	4.60E-05 tpy
193-39-5	Indeno(1,2,3-cd)pyrene	2.14E-06 lb/MMBtu	2.20E-05 tpy
91-20-3	Naphthalene	1.13E-03 lb/MMBtu	1.16E-02 tpy
85-01-8	Phenanthrene	1.05E-05 lb/MMBtu	1.08E-04 tpy
129-00-0	Pyrene	4.25E-06 lb/MMBtu	4.38E-05 tpy
		Total Potential HAP Emissions:	**0.43 tpy**

Notes:

[1] Total fuel use based on maximum full-time operation or permit-limited operation as noted below.

EU ID 8	Heater		20.6 MMBtu/hr
			500 hr/yr
		Potential Heat Input:	10,300 MMBtu/yr
EU ID 9	Heater		20.6 MMBtu/hr
			500 hr/yr
		Potential Heat Input:	10,300 MMBtu/yr
		Total Potential Heat Input:	**20,600 MMBtu/yr**

[2] Reference: AP-42, Tables 1.3-9 and 1.3-10

[3] Diesel average heat value: Table 1.3-1, AP-42. 139 MMBtu/1000 gal

Table D1-11. Potential Annual Emissions (after controls/limitations) Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Natural Gas Fired Turbines

2,092,475 MMBtu/yr [1]

CAS No.	Chemical Name	Source Category Emission Calculations AP-42 Emission Factor [2]		Estimated Emissions	
	1,3 Butadiene	4.30E-07	lb/MMBtu	4.50E-04	tpy
	Acetaldehyde	4.00E-05	lb/MMBtu	4.18E-02	tpy
	Acrolein	6.40E-06	lb/MMBtu	6.70E-03	tpy
71-43-2	Benzene	1.20E-05	lb/MMBtu	1.26E-02	tpy
100-41-4	Ethyl benzene	3.20E-05	lb/MMBtu	3.35E-02	tpy
50-00-0	Formaldehyde	7.10E-04	lb/MMBtu	7.43E-01	tpy
	Napthalene	1.30E-06	lb/MMBtu	1.36E-03	tpy
	Polycyclic aromatic compounds(PAH)	2.20E-06	lb/MMBtu	2.30E-03	tpy
	Propylene Oxide	2.90E-05	lb/MMBtu	3.03E-02	tpy
108-88-3	Toluene	1.30E-04	lb/MMBtu	1.36E-01	tpy
1330-20-7	Xylenes (isomers and mixture)	6.40E-05	lb/MMBtu	6.70E-02	tpy
				1.07E+00	**tpy**

Notes:
[1] Total fuel use based on maximum full-time operation or permit-limited operation as noted below.

EU ID 12	Cyclone Turbine		121.1	MMBtu/hr
			8,520	hr/yr
		Potential Heat Input:	1,031,706	MMBtu/yr
EU ID 13	Cyclone Turbine		121.1	MMBtu/hr
			8,760	hr/yr
		Potential Heat Input:	1,060,769	MMBtu/yr
		Total Potential Heat Input:	**2,092,475**	**MMBtu/yr**
		Average BSFC, Table 3.4-1, AP-42	7,000	Btu/hp-hr

[2] Reference: AP-42, Tables 3.1-3

Table D1-12. Potential Annual Emissions (after controls/limitations) Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Diesel Fired Turbines

29,062 MMBtu/yr [1]

		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**AP-42 Emission Factor** [2]	**Estimated Emissions**
	1,3 Butadiene	1.60E-05 lb/MMBtu	2.32E-04 tpy
71-43-2	Benzene	5.50E-05 lb/MMBtu	7.99E-04 tpy
50-00-0	Formaldehyde	2.80E-04 lb/MMBtu	4.07E-03 tpy
	Napthalene	3.50E-05 lb/MMBtu	5.09E-04 tpy
	Polycyclic aromatic compounds(PAH)	4.00E-05 lb/MMBtu	5.81E-04 tpy
	Arsenic	1.10E-05 lb/MMBtu	1.60E-04 tpy
	Beryllium	3.10E-07 lb/MMBtu	4.50E-06 tpy
	Cadmium	4.80E-06 lb/MMBtu	6.97E-05 tpy
	Chromium	1.10E-05 lb/MMBtu	1.60E-04 tpy
	Lead	1.40E-05 lb/MMBtu	2.03E-04 tpy
	Manganese	7.90E-04 lb/MMBtu	1.15E-02 tpy
	Mercury	1.20E-06 lb/MMBtu	1.74E-05 tpy
	Nickel	4.60E-06 lb/MMBtu	6.68E-05 tpy
	Selenium	2.50E-05 lb/MMBtu	3.63E-04 tpy
		Total Potential HAP Emissions:	**1.87E-02 tpy**

Notes:
[1] Total fuel use based on maximum full-time operation or permit-limited operation as noted below.

EU ID 12	Cyclone Turbine	121.1	MMBtu/hr
		240	hr/yr
	Potential Heat Input:	29,062	MMBtu/yr
	Total Potential Heat Input:	**29,062**	**MMBtu/yr**
	Average BSFC, Table 3.4-1, AP-42	7,000	Btu/hp-hr

[2] Reference: AP-42, Tables 3.1-4, 3.1-5

Table D1-13. Potential Annual Emissions (after controls/limitations) Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Piping Fugitives - Light Liquid Service

1. Assume that the TOC emissions (losses) are determined from emission factors in Protocol for Equipment Leak Estimates, EPA-453-95-017, November 1995.

2. Based on this protocol, and a TAPs facilities fugitive emissions study conducted by Alyeska in 1998, the potential TOC emissions for PS 4 are estimated to be:
45 tpy (Light Liquid Service)

3. Conservatively assuming that the light liquid piping leaks are all associated with crude, the individual component emission rates (losses) are then determined using the crude liquid phase weight fractions as determined by Core Laboratories.

Calculation of Component Emission Rates (Losses) - Light Liquids				
Component	Component Weight Fraction in Crude (wt%/100)	Total Light Liquid TOC Fugitive Losses (tpy)	Component Emission Rate/Loss (tpy)	Total HAP Light Liquid Fugitive Emissions/Losses (tpy)
Methane	0	45	0.0	N/A
Ethane	0.0002	45	0.01	N/A
Propane	0.003	45	0.1	N/A
Isobutane	0.0044	45	0.2	N/A
N-Butane	0.0152	45	0.7	N/A
1,3 Butadiene	0	45	0.0	0
Isopentane	0.0088	45	0.4	N/A
N-Pentane	0.0127	45	0.6	N/A
N-Hexane	0.0104	45	0.5	0.47
Hexanes	0.0118	45	0.5	N/A
Benzene	0.0033	45	0.1	0.15
Heptanes	0.0392	45	1.8	N/A
2,2,4 Trimethylpentane	0	45	0	0
Toluene	0.0084	45	0.4	0.38
Octanes	0.0464	45	2.1	N/A
Ethyl Benzene	0.002	45	0.1	0.09
Xylenes	0.0095	45	0.4	0.43
Isopropylbenzene	0.0005	45	0.02	0.02
Nonanes	0.031	45	1.4	N/A
Naphthalene	0.0016	45	0.07	0.07
Decanes+	0.7916	45	35.6	N/A
Total Potential HAP Emissions:	**1.0**		**45**	**1.6**

Table D1-14. Potential Annual Emissions (after controls/limitations) Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Piping Fugitives - Gas/Vapor Service

1. Assume that the TOC emissions (losses) are determined from emission factors in Protocol for Equipment Leak Estimates, EPA-453-95-017, November 1995.

2. Based on this protocol, and a TAPs facilities fugitive emissions study conducted by Alyeska in 1998, the potential TOC emissions for PS 4 are estimated to be:
176 tpy (Gas/Vapor Service)

3. Assuming that the gas/vapor piping leaks are all associated with fuel gas, the individual component emission rates (losses) are then determined using the weight fractions previously calculated.

Calculation of Component Emission Rates (Losses) - Gas/Vapor Service					
Component	Component Weight Fraction in Fuel Gas	Normalized Component Weight Fraction in Fuel Gas	Total Gas/Vapor TOC Fugitive Losses (tpy)	Component Emission Rate/Loss (tpy)	Total HAP Fuel Gas Fugitive Emissions/Losses (tpy)
Methane	0.56826	0.77321	176	136.1	N/A
Ethane	0.07875	0.10715	176	18.9	N/A
Propane	0.04214	0.05734	176	10.1	N/A
Isobutane	0.03578	0.04869	176	8.6	N/A
N-Butane	0.00614	0.00836	176	1.5	N/A
1,3 Butadiene	0	0	176	0	0
Isopentane	0.00099	0.00135	176	0.24	N/A
N-Pentane	0.00099	0.00135	176	0.24	N/A
N-Hexane	0.00020	0.00027	176	0.05	0.05
Hexanes+	0.00118	0.00161	176	0.28	N/A
Benzene	0.00007	0.00010	176	0.02	0.02
2,2,4 Trimethylpentane	0	0	176	0	0
Toluene	0.00042	0.00058	176	0.10	0.10
Ethyl Benzene	0	0	176	0	0
Xylenes	0	0	176	0	0
Isopropylbenzene	0	0	176	0	0
Napthalene	0	0	176	0	0
otal Potential HAP Emissions:	**0.73**	**1.0**		**176**	**0.2**

Notes:
1. The component weight fractions in the fuel gas were normalized to eliminate the non-organic components N_2 and CO_2.

Table D1-15. Potential Annual Emissions (after controls/limitations) Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Diesel Engines Less Than 600 Horsepower

Maximum Total Heat Input: 183.0 MMBtu/yr [1]

Section 112 Hazardous Air Pollutants			Source Category Emission Calculations	
No.	**CAS No.**	**Chemical Name**	**Emission Factor [2]**	**Estimated Emissions**
1	75070	Acetaldehyde	7.67E-04 lb/MMBtu	7.02E-05 tpy
6	107028	Acrolein	9.25E-05 lb/MMBtu	8.47E-06 tpy
15	71432	Benzene	9.33E-04 lb/MMBtu	8.54E-05 tpy
23	106990	1,3-Butadiene	3.91E-05 lb/MMBtu	3.58E-06 tpy
87	5000	Formaldehyde	1.18E-03 lb/MMBtu	1.08E-04 tpy
152	108883	Toluene	4.09E-04 lb/MMBtu	3.74E-05 tpy
169	1330207	Xylenes (isomers and mixture)	2.85E-04 lb/MMBtu	2.61E-05 tpy
187	N/A	Polycyclic Organic Matter (POM)	1.68E-04 lb/MMBtu	1.54E-05 tpy
		Polycyclic aromatic compounds(PAH)		
119	91203	Naphthalene	8.48E-05 lb/MMBtu	7.76E-06 tpy
		Acenaphthylene	5.06E-06 lb/MMBtu	4.63E-07 tpy
		Acenaphthene	1.42E-06 lb/MMBtu	1.30E-07 tpy
		Fluorene	2.92E-05 lb/MMBtu	2.67E-06 tpy
		Phenanthrene	2.94E-05 lb/MMBtu	2.69E-06 tpy
		Anthracene	1.87E-06 lb/MMBtu	1.71E-07 tpy
		Fluoranthene	7.61E-06 lb/MMBtu	6.96E-07 tpy
		Pyrene	4.78E-06 lb/MMBtu	4.37E-07 tpy
		Benzo(a)anthracene	1.68E-06 lb/MMBtu	1.54E-07 tpy
		Chrysene	3.53E-07 lb/MMBtu	3.23E-08 tpy
		Benzo(b)fluoranthene	9.91E-08 lb/MMBtu	9.07E-09 tpy
		Benzo(k)fluoranthene	1.55E-07 lb/MMBtu	1.42E-08 tpy
		Benzo(a)pyrene	1.88E-07 lb/MMBtu	1.72E-08 tpy
		Indeno(1,2,3-cd)pyrene	3.75E-07 lb/MMBtu	3.43E-08 tpy
		Dibenz(a,h)anthracene	5.83E-07 lb/MMBtu	5.34E-08 tpy
		Benzo(g,h,l)perylene	4.89E-07 lb/MMBtu	4.48E-08 tpy
			Total Potential HAP Emissions:	**3.55E-04 tpy**

Notes:
[1] Total fuel use based on maximum full-time operation or permit-limited operation as noted below.

EU ID 15	Generator Engine	0.6 MMBtu/hr
		300 hrs
	Potential Heat Input:	183 MMBtu/yr
	Total Potential Heat Input:	**183 MMBtu/yr**
Engines heat rate:		7,000 Btu/hp-hr
Diesel High Heat Value: AP-42 Table 1.3-1		139 MMBtu/10^3 gal

[2] Reference: AP-42, Table 3.3-2.

Table D1-16. Potential Annual Emissions (after controls/limitations) Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Diesel Engines Greater Than or Equal to 600 Horsepower

Maximum Total Heat Input: 12,672.5 MMBtu/yr [1]

CAS No.	Chemical Name	Emission Factor [2]	Estimated Emissions
		Source Category Emission Calculations	
75-07-0	Acetaldehyde	2.52E-05 lb/MMBtu	1.60E-04 tpy
107-02-8	Acrolein	7.88E-06 lb/MMBtu	4.99E-05 tpy
71-43-2	Benzene	7.76E-04 lb/MMBtu	4.92E-03 tpy
50-00-0	Formaldehyde	7.89E-05 lb/MMBtu	5.00E-04 tpy
108-88-3	Toluene	2.81E-04 lb/MMBtu	1.78E-03 tpy
1330-20-7	Xylenes (isomers and mixture)	1.93E-04 lb/MMBtu	1.22E-03 tpy
N/A	Polycyclic Organic Matter (POM)	2.12E-04 lb/MMBtu	1.34E-03 tpy
	Polycyclic aromatic compounds(PAH)		
	Acenaphthene	4.68E-06 lb/MMBtu	2.97E-05 tpy
	Acenaphthylene	9.23E-06 lb/MMBtu	5.85E-05 tpy
	Anthracene	1.23E-06 lb/MMBtu	7.79E-06 tpy
	Benzo(a)anthracene	6.22E-07 lb/MMBtu	3.94E-06 tpy
	Benzo(b)fluoranthene	1.11E-06 lb/MMBtu	7.03E-06 tpy
	Benzo(k)fluoranthene	2.18E-07 lb/MMBtu	1.38E-06 tpy
	Benzo(a)pyrene	2.57E-07 lb/MMBtu	1.63E-06 tpy
	Benzo(g,h,l)perylene	5.56E-07 lb/MMBtu	3.52E-06 tpy
	Chrysene	1.53E-06 lb/MMBtu	9.69E-06 tpy
	Dibenz(a,h)anthracene	3.46E-07 lb/MMBtu	2.19E-06 tpy
	Fluoranthene	4.03E-06 lb/MMBtu	2.55E-05 tpy
	Fluorene	1.28E-05 lb/MMBtu	8.11E-05 tpy
	Indeno(1,2,3-cd)pyrene	4.14E-07 lb/MMBtu	2.62E-06 tpy
91-20-3	Naphthalene	1.30E-04 lb/MMBtu	8.24E-04 tpy
	Phenanthrene	4.08E-05 lb/MMBtu	2.59E-04 tpy
	Pyrene	3.71E-06 lb/MMBtu	2.35E-05 tpy
		Total Potential HAP Emissions:	**9.97E-03 tpy**

Notes:
[1] Total fuel use based on maximum full-time operation or permit-limited operation as noted below:

EU ID 14	Generator Engine		21.1 MMBtu/hr
			600 hrs
		Potential Heat Input:	12,672 MMBtu/yr
EU ID 22	Generator Engine		7.5 MMBtu/hr
			200 hrs
		Potential Heat Input:	1,502 MMBtu/yr
		Total Potential Heat Input:	**12,672 MMBtu/yr**
Engines heat rate:			7,000 Btu/hp-hr

[2] Reference: AP-42, Table 3.4-3 and Table 3.4-4

Table D1-17. Potential Annual Emissions (after controls/limitations) Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Insignificant Emission Units - Natural Gas Fired Heaters

73,812 MMBtu/yr [1]

		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**AP-42 Emission Factor [2]**	**Estimated Emissions [3]**
91-57-6	2-Methylnapthalene	2.40E-05 lb/MMscf	8.68E-07 tpy
56-49-5	3-Methylcholanthrene	1.80E-06 lb/MMscf	6.51E-08 tpy
	7,12-Dimethylbenz(a)anthracene	1.60E-05 lb/MMscf	5.79E-07 tpy
83-32-9	Acenaphthene	1.80E-06 lb/MMscf	6.51E-08 tpy
203-96-8	Acenaphthylene	1.80E-06 lb/MMscf	6.51E-08 tpy
120-12-7	Anthracene	2.40E-06 lb/MMscf	8.68E-08 tpy
56-55-3	Benz(a)anthracene	1.80E-06 lb/MMscf	6.51E-08 tpy
71-43-2	Benzene	2.10E-03 lb/MMscf	7.60E-05 tpy
50-32-8	Benzo(a)pyrene	1.20E-06 lb/MMscf	4.34E-08 tpy
205-99-2	Benzo(b)fluoranthene	1.80E-06 lb/MMscf	6.51E-08 tpy
191-24-2	Benzo(g,h,i)perylene	1.20E-06 lb/MMscf	4.34E-08 tpy
207-08-9	Benzo(k)fluoranthene	1.80E-06 lb/MMscf	6.51E-08 tpy
218-01-9	Chrysene	1.80E-06 lb/MMscf	6.51E-08 tpy
53-70-3	Dibenzo(a,h)anthracene	1.20E-06 lb/MMscf	4.34E-08 tpy
25321-22-6	Dichlorobenzene	1.20E-03 lb/MMscf	4.34E-05 tpy
206-44-0	Fluoranthene	3.00E-06 lb/MMscf	1.09E-07 tpy
86-73-7	Fluorene	2.80E-06 lb/MMscf	1.01E-07 tpy
50-00-0	Formaldehyde	7.50E-02 lb/MMscf	2.71E-03 tpy
110-54-3	Hexane	1.80E+00 lb/MMscf	6.51E-02 tpy
193-39-5	Indeno(1,2,3-cd)pyrene	1.80E-06 lb/MMscf	6.51E-08 tpy
91-20-3	Naphthalene	6.10E-04 lb/MMscf	2.21E-05 tpy
85-01-8	Phenanathrene	1.70E-05 lb/MMscf	6.15E-07 tpy
129-00-0	Pyrene	5.00E-06 lb/MMscf	1.81E-07 tpy
108-88-3	Toluene	3.40E-03 lb/MMscf	1.23E-04 tpy
7440-38-2	Arsenic	2.00E-04 lb/MMscf	7.24E-06 tpy
7440-41-7	Beryllium	1.20E-05 lb/MMscf	4.34E-07 tpy
7440-43-9	Cadmium	1.10E-03 lb/MMscf	3.98E-05 tpy
7440-47-3	Chromium	1.40E-03 lb/MMscf	5.07E-05 tpy
7440-48-4	Cobalt	8.40E-05 lb/MMscf	3.04E-06 tpy
7439-96-5	Manganese	3.80E-04 lb/MMscf	1.37E-05 tpy
7439-97-6	Mercury	2.60E-04 lb/MMscf	9.41E-06 tpy
7440-02-0	Nickel	2.10E-03 lb/MMscf	7.60E-05 tpy
7782-49-2	Selenium	2.40E-05 lb/MMscf	8.68E-07 tpy
		Total Potential HAP Emissions:	**6.83E-02 tpy**

Notes:
[1] Total fuel use based on maximum full-time operation or permit-limited operation as noted below.

Insignificant EUs	Various		8.4 MMBtu/hr
			8,760 hr/yr
		Potential Heat Input:	73,812 MMBtu/yr
		Total Potential Heat Input:	**73,812 MMBtu/yr**

[2] Reference: AP-42, Tables 1.4-3 and 1.4-4.
[3] Natural Gas High Heat Value: AP-42 Table 1.4-2 1,020 Btu/scf

Table D1-18. Potential Annual Emissions (after controls/limitations) Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Insignificant Emission Units - Diesel Fired Heaters

Potential Total Heat Input for Insignificant Emissions Units: **32,412 MMBtu/yr** [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**AP-42 Emission Factor** [2]	**Estimated Emissions**
N/A	Arsenic Compounds	4.00E-06 lb/MMBtu	6.48E-05 tpy
71-43-2	Benzene	2.10E-04 lb/MMBtu	3.40E-03 tpy
N/A	Beryllium Compounds	3.00E-06 lb/MMBtu	4.86E-05 tpy
N/A	Cadmium Compounds	3.00E-06 lb/MMBtu	4.86E-05 tpy
N/A	Chromium Compounds	3.00E-06 lb/MMBtu	4.86E-05 tpy
100-41-4	Ethyl benzene	6.36E-05 lb/MMBtu	1.03E-03 tpy
50-00-0	Formaldehyde	3.30E-02 lb/MMBtu	5.35E-01 tpy
N/A	Lead Compounds	9.00E-06 lb/MMBtu	1.46E-04 tpy
N/A	Manganese Compounds	6.00E-06 lb/MMBtu	9.72E-05 tpy
N/A	Mercury Compounds	3.00E-06 lb/MMBtu	4.86E-05 tpy
N/A	Nickel Compounds	3.00E-06 lb/MMBtu	4.86E-05 tpy
N/A	Selenium Compounds	1.50E-05 lb/MMBtu	2.43E-04 tpy
108-88-3	Toluene	6.20E-03 lb/MMBtu	1.00E-01 tpy
71-55-6	1,1,1-Trichloroethane	2.36E-04 lb/MMBtu	3.82E-03 tpy
1330-20-7	Xylenes	1.09E-04 lb/MMBtu	1.77E-03 tpy
N/A	Polycyclic Organic Matter (POM)		2.34E-02 tpy
N/A	Polycyclic aromatic compounds(PAH)		2.34E-02 tpy
208-96-8	Acenaphthene	2.11E-05 lb/MMBtu	3.42E-04 tpy
83-32-9	Acenaphthylene	2.53E-04 lb/MMBtu	4.10E-03 tpy
120-12-7	Anthracene	1.22E-06 lb/MMBtu	1.98E-05 tpy
56-55-3	Benzo(a)anthracene	4.01E-06 lb/MMBtu	6.50E-05 tpy
205-99-2	Benzo(b,k)fluoranthene	1.48E-06 lb/MMBtu	2.40E-05 tpy
191-24-2	Benzo(g,h,i)perylene	2.26E-06 lb/MMBtu	3.66E-05 tpy
218-01-9	Chrysene	2.38E-06 lb/MMBtu	3.86E-05 tpy
53-70-3	Dibenz(a,h)anthracene	1.67E-06 lb/MMBtu	2.71E-05 tpy
206-44-0	Fluoranthene	4.84E-06 lb/MMBtu	7.84E-05 tpy
86-73-7	Fluorene	4.47E-06 lb/MMBtu	7.24E-05 tpy
193-39-5	Indeno(1,2,3-cd)pyrene	2.14E-06 lb/MMBtu	3.47E-05 tpy
91-20-3	Naphthalene	1.13E-03 lb/MMBtu	1.83E-02 tpy
85-01-8	Phenanthrene	1.05E-05 lb/MMBtu	1.70E-04 tpy
129-00-0	Pyrene	4.25E-06 lb/MMBtu	6.89E-05 tpy
		Total Potential HAP Emissions:	**6.69E-01 tpy**

Notes:
[1] Total fuel use based on maximum full-time operation or permit-limited operation as noted below.

Insignificant EUs	Various		3.7 MMBtu/hr
			8,760 hr/yr
		Potential Heat Input:	32,412 MMBtu/yr
		Total Potential Heat Input:	**32,412 MMBtu/yr**

[2] Reference: AP-42, Tables 1.3-9 and 1.3-10

Table D1-19a. Estimating Procedure for Determining HAP Content of Crude Storage Tank Vapors
Alyeska Pipeline Services Company - Pump Station 4

I. Sample Description/Comments

1. PS 1 discharge stream sample
2. Sample Date: 10/31/02
3. Sample ID: L1-021031-06
4. Core Laboratories data includes crude molecular weight and component wt% values.

II. Determine Component Mole Fractions in Liquid Crude

Methodology Assumptions/Comments:
1. The component mole fraction in crude is determined from component weight fraction and component molecular weight by assuming a mass of 1,000 lb of crude (see AP-42 Section 7.1.5).

2. The component molecular weight of Decanes+ is equal to the value required for the sum of all molecular weights to be equal to the Core Laboratories measured crude molecular weight of: 232 lb/lb-mole

Liquid Crude Analysis Data		Calculate Component Mole Fraction in Crude			
Component **i**	Component Weight Fraction in Crude (wt%/100) Z_{Li}	Component Molecular Weight M_i	Total Moles of Crude (sum ZL_i/M_i x1000) x_T	Component Mole Fraction in Crude ($Z_{Li}/M_i/x_T$) x_i	Crude Molecular Weight (sum $Mi*x_i$) M_T
Methane	0	16	0.000	0.000	0.000
Ethane	0.0002	30	0.007	0.002	0.046
Propane	0.003	44	0.068	0.016	0.696
Isobutane	0.0044	58	0.076	0.018	1.021
N-Butane	0.0152	58	0.262	0.061	3.529
1,3 Butadiene	0	54	0.000	0.000	0.000
Isopentane	0.0088	72	0.122	0.028	2.043
N-Pentane	0.0127	72	0.176	0.041	2.948
N-Hexane	0.0104	86	0.121	0.028	2.414
Hexanes	0.0118	84	0.140	0.033	2.739
Benzene	0.0033	78	0.042	0.010	0.766
Heptanes	0.0392	97	0.404	0.094	9.100
2,2,4 Trimethylpentane	0	114	0.000	0.000	0.000
Toluene	0.0084	92	0.091	0.021	1.950
Octanes	0.0464	111	0.418	0.097	10.771
Ethyl Benzene	0.002	106	0.019	0.004	0.464
Xylenes	0.0095	106	0.090	0.021	2.205
Isopropylbenzene	0.0005	120	0.004	0.001	0.116
Nonanes	0.031	123	0.252	0.059	7.196
Naphthalene	0.0016	128	0.012	0.003	0.371
Decanes+	0.7916	395	2.004	0.465	183.76
SUM Z_{Li} / x_T / x_i / M_T	1.00		4.308	1.000	232

Notes:
1. Molecular weight values for component groups such as octanes are estimates from Core Laboratories.

Table D1-19b. Estimating Procedure for Determining HAP Content of Crude Storage Tank Vapors
Alyeska Pipeline Services Company - Pump Station 4

III. Determine Component Vapor Pressure at Given Crude Temperature

Methodology Assumptions/Comments:
1. Clausius-Clapeyron equation provides relationship between temperature and vapor pressure:

$$\log P_2/P_1 = H_v/2.303R^*(T_2-T_1/T_2T_1)$$

where R = Universal Gas Constant = 8.31448 J/g-mole·K = 3.58 Btu/lb-mole·K
Hv = Heat of Vaporization = see table below

2. Let P_1 be known component vapor pressure at known temperature T_1 = 100 F (311 K),
and P_2 be unknown component vapor pressure at given crude temperature T_2 (shown below).

3. PS 3 crude (and vapor) constant temperature (P_2) of: 99 F 310 K
Based on average crude temperature at PS 4 during peak flow year 1995.

Component Physical Properties			Component Vapor Pressure at Crude Temperature			
Component **i**	Component Vapor Pressureat 100F (psia) **P_1**	Component Heat of Vaporization (Btu/lb-mole) **H_v**	Component Heat of Vaporization/Gas Constant H_v/2.303R	Calculate $(T_2-T_1)/T_2T_1$	Calculate Inverse Log of $(H_v/2.303R)^*(T_2-T_1)/T_2T_1$	Component Vapor Pressure at Crude Temperature (psia) **P_2**
Methane	5000	3520	426.9	-0.00001	0.994	4972
Ethane	800	6349	770.1	-0.00001	0.990	792
Propane	189	8071	978.9	-0.00001	0.987	186
Isobutane	72.6	9136	1108.2	-0.00001	0.985	71.5
N-Butane	51.7	9642	1169.5	-0.00001	0.985	50.9
1,3 Butadiene	59.5	10025	1215.9	-0.00001	0.984	58.5
Isopentane	20.4	10613	1287.3	-0.00001	0.983	20.1
N-Pentane	15.6	11082	1344.2	-0.00001	0.982	15.3
N-Hexane	4.96	12404	1504.5	-0.00001	0.980	4.86
Hexanes	10	12500	1516.1	-0.00001	0.980	9.80
Benzene	3.22	13215	1602.8	-0.00001	0.979	3.15
Heptanes	3.5	13500	1637.4	-0.00001	0.978	3.42
2,2,4 Trimethylpentane	1.70	14000	1698.1	-0.00001	0.978	1.7
Toluene	1.03	14263	1730.0	-0.00001	0.977	1.01
Octanes	1	14500	1758.7	-0.00001	0.977	0.98
Ethyl Benzene	0.37	15288	1854.3	-0.00001	0.976	0.36
Xylenes	0.33	16000	1940.6	-0.00001	0.975	0.32
Isopropylbenzene	0.19	16136	1957.1	-0.00001	0.974	0.19
Nonanes	0.40	16500	2001.3	-0.00001	0.974	0.39
Naphthalene	0.13	16700	2025.5	-0.00001	0.973	0.13
Decanes+	0.1	47282	5734.7	-0.00001	0.927	0.09

Notes:
1. Heat of Vaporization and vapor pressure of pure components from GPSA Engineering Data Book, Volume II, Section 23.
2. Vapor pressure values for component groups such as octanes are estimates from Core Laboratories.
3. Heat of Vaporization for component groups are estimates based on values for individual components within the group.

Table D1-19c. Estimating Procedure for Determining HAP Content of Crude Storage Tank Vapors
Alyeska Pipeline Services Company - Pump Station 4

IV. Determine Component Partial Pressure and Mole Fraction in Crude Vapor

Methodology Assumptions/Comments:

1. Conservatively assume C_1-C_{10} hydrocarbons and HAPs are only species present in vapor phase due to dramatic dropoff in component vapor pressue as component molecular weight increases.

2. For speciation purposes, assume crude vapor pressure (P_{VA}) equal to sum of component partial pressures indicated below. This assumption ignores CO_2 present in crude and is conservative because it results in vapor mole fractions of listed components (including HAPs) being overstated.

3. Component partial pressure is equal to the component mole fraction in the liquid crude multiplied by the component vapor pressure at the given crude temperature:

$$P_i = P_2 * x_i$$

4. The component mole fraction in the crude vapor is then equal to the component partial pressure divided by the overall crude vapor pressure:

$$y_i = P_i / P_{VA}$$

	Calculation of Component Partial Pressure and Mole Fraction in Vapor			
Component **i**	Component Vapor Pressure at Crude Temperature (psia) **P_2**	Component Mole Fraction in Crude ($Z_{Li}/M_i/x_T$) **x_i**	Component Partial Pressure at Crude Temperature (P_2*x_i) **P_i**	Component Mole Fraction in Vapor (P_i/P_{VA}) **y_i**
Methane	4972	0.0000	0.000	0.0000
Ethane	792	0.0015	1.223	0.1142
Propane	186	0.0158	2.940	0.2747
Isobutane	71.5	0.0176	1.257	0.1174
N-Butane	50.9	0.0607	3.090	0.2887
1,3 Butadiene	58.5	0.0000	0.000	0.0000
Isopentane	20.1	0.0283	0.569	0.0531
N-Pentane	15.3	0.0409	0.626	0.0585
N-Hexane	4.86	0.0280	0.136	0.0127
Hexanes	9.80	0.0326	0.320	0.0299
Benzene	3.15	0.0098	0.031	0.0029
Heptanes	3.42	0.0938	0.321	0.0300
2,2,4 Trimethylpentane	1.66	0.0000	0.000	0.0000
Toluene	1.01	0.0212	0.021	0.0020
Octanes	0.98	0.0970	0.095	0.0089
Ethyl Benzene	0.36	0.0044	0.002	0.0001
Xylenes	0.32	0.0208	0.007	0.0006
Isopropylbenzene	0.19	0.0010	0.000	0.0000
Nonanes	0.39	0.0585	0.023	0.0021
Naphthalene	0.13	0.0029	0.000	0.0000
Decanes+	0.09	0.4652	0.043	0.0040
P_{VA} / y_i SUM			10.7	1.00

Table D1-19d. Estimating Procedure for Determining HAP Content of Crude Storage Tank Vapors
Alyeska Pipeline Services Company - Pump Station 4

V. Determine Component Weight Fractions in Crude Vapor

1. Component weight fraction in the vapor is determined in two steps. First, the overall vapor molecular weight is determined by summing the product of the molecular weight and vapor mole fraction for each component:

$$M_V = \text{sum } (M_i{*}y_i)$$

2. Then, the component weight fraction is determined by dividing the product of the molecular weight and vapor mole fraction for each component by the overall vapor molecular weight:

$$Z_{Vi} = (M_i{*}y_i)/M_V$$

Component Physical Properties		Calculation of Component Weight Fraction in Vapor		
Component **i**	Component Molecular Weigh **M_i**	Component Mole Fraction in Vapor (P_i/P_{VA}) **y_i**	Calculate Vapor Molecular Weight (sum $M_i{*}y_i$) **M_V**	Component Weight Fraction in Vapor ($Mi{*}y_i/M_V$) **Z_{Vi}**
Methane	16	0.0000	0.00	0.0000
Ethane	30	0.1142	3.43	0.0602
Propane	44	0.2747	12.11	0.2123
Isobutane	58	0.1174	6.83	0.1196
N-Butane	58	0.2887	16.78	0.2941
1,3 Butadiene	54	0.0000	0.00	0.0000
Isopentane	72	0.0531	3.83	0.0672
N-Pentane	72	0.0585	4.22	0.0740
N-Hexane	86	0.0127	1.10	0.0192
Hexanes	84	0.0299	2.51	0.0440
Benzene	78	0.0029	0.23	0.0040
Heptanes	97	0.0300	2.91	0.0510
2,2,4 Trimethylpentane	114	0.0000	0.00	0.0000
Toluene	92	0.0020	0.18	0.0032
Octanes	111	0.0089	0.98	0.0172
Ethyl Benzene	106	0.0001	0.02	0.0003
Xylenes	106	0.0006	0.07	0.0012
Isopropylbenzene	120	0.0000	0.00	0.0000
Nonanes	123	0.0021	0.26	0.0046
Naphthalene	128	0.0000	0.00	0.0001
Decanes+	395	0.0040	1.59	0.0279
y_i SUM / M_{v} / Z_{vi} SUM		1.00	57.1	1.00

Table D1-20. Potential Annual Emissions (after controls/limitations) Calculations - Greenhouse Gas (GHG) Summary
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel Type	Potential Greenhouse Gas Emissions (tpy)				
ID	Description	Rating/Capacity		CO_2	CH_4	N_2O	GHG Mass	GHG CO_2e [1]
Significant Emissions Units								
8	Heater	20.6 MMBtu/hr	Natural Gas	9,931	0.2	0.02	9,932	9,942
			Diesel	381	0.02	0.00	381	382
9	Heater	20.6 MMBtu/hr	Natural Gas	9,931	0.2	0.02	9,932	9,942
			Diesel	381	0.02	0.00	381	382
12	Cyclone Turbine	12.9 MW	Natural Gas	60,217	1.1	0.1	60,218	60,278
			Diesel	2,364	0.1	0.02	2,364	2,372
13	Cyclone Turbine	12.9 MW	Natural Gas	61,913	1.2	0.1	61,914	61,976
14	Generator Engine	2,250 kW	Diesel	1,031	0.04	8.4	1,039	3,249
15	Generator Engine	65 kW	Diesel	15	6.0E-04	1.2E-04	15	15
21	Breakout Tank 140	55,000 bbl	N/A	0	0	0	0	0
22	Generator Engine	800 kWe	Diesel	122	5.0E-03	9.9E-04	122	123
Significant Emissions Units Emissions - Greenhouse Gases							**146,298**	**148,660**
Insignificant Emissions Unit								
N/A	Heater	0.763 MMBtu/hr	Natural Gas	390	0.007	7.4E-04	390	391
N/A	Heater	0.763 MMBtu/hr	Natural Gas	390	0.007	7.4E-04	390	391
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Diesel	356	0.01	0.003	356	358
N/A	Heater	0.600 MMBtu/hr	Diesel	428	0.02	0.003	428	429
N/A	Heater	0.600 MMBtu/hr	Diesel	428	0.02	0.003	428	429
N/A	Heater	0.800 MMBtu/hr	Diesel	570	0.02	0.005	570	572
N/A	Heater	0.800 MMBtu/hr	Diesel	570	0.02	0.005	570	572
N/A	Heater	0.400 MMBtu/hr	Diesel	285	0.01	0.002	285	286
Insignificant Emissions Unit Emissions - Greenhouse Gases							**6,945**	**6,958**
Total Emissions - Greenhouse Gases							**153,243**	**155,619**

Notes:
[1] GHG emissions are defined as CO_2e emissions.
Per 40 CFR 98. Table A-1. Please note CO_2e is the summation of CO_2 (1), CH_4 (28), and N_2O (265), applying the global warming potential for each pollutant.

Table D1-21. Potential Annual Emissions (after controls/limitations) Calculations - Carbon Dioxide (CO_2)
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel	Factor	CO_2 Emission	Potential	Potential
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	CO_2 Emissions [1]
Significant Emissions Units							
8	Heater	20.6 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,260 hours	9,931 tpy
			Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	500 hours	381 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,260 hours	9,931 tpy
			Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	500 hours	381 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,520 hours	60,217 tpy
			Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	240 hours	2,364 tpy
13	Cyclone Turbine	12.9 MW	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	61,913 tpy
14	Generator Engine	2,250 kW	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	600 hours	1,031 tpy
15	Generator Engine	65 kW	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	300 hours	15 tpy
21	Breakout Tank 140	55,000 bbl	N/A	N/A	N/A	8,760 hours	0 tpy
22	Generator Engine	800 kWe	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	200 hours	122.2 tpy
Significant Emissions Units Emissions - CO_2							**146,286 tpy**
Insignificant Emissions Units							
N/A	Heater	0.763 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	390 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	390 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours	356 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours	428 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours	428 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours	570 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours	570 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours	285 tpy
Insignificant Emissions Units Emissions - CO_2							**6,945 tpy**
Total Emissions - CO_2							**153,231 tpy**

Notes:
[1] Parameters and conversions:
Diesel High Heat Value: AP-42 Table 1.3-1 — 139 MMBtu/1000 gal
Average BSFC, Table 3.4-1, AP-42 — 7,000 Btu/hp-hr

Table D1-22. Potential Annual Emissions (after controls/limitations) Calculations - Methane (CH_4)
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit ID	Description	Rating/Capacity	Fuel Type	Factor Reference	CH_4 Emission Factor	Potential Operation	Potential CH_4 Emissions [1]
Significant Emissions Units							
8	Heater	20.6 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	0.001 kg/MMBtu	8,260 hours	0.2 tpy
			Diesel	40 CFR 98, Table C-1	0.003 kg/MMBtu	500 hours	0.02 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	0.001 kg/MMBtu	8,260 hours	0.2 tpy
			Diesel	40 CFR 98, Table C-1	0.003 kg/MMBtu	500 hours	0.02 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	40 CFR 98, Table C-1	0.001 kg/MMBtu	8,520 hours	1.1 tpy
			Diesel	40 CFR 98, Table C-1	0.003 kg/MMBtu	240 hours	0.10 tpy
13	Cyclone Turbine	12.9 MW	Natural Gas	40 CFR 98, Table C-1	0.001 kg/MMBtu	8,760 hours	1.2 tpy
14	Generator Engine	2,250 kW	Diesel	40 CFR 98, Table C-1	0.003 kg/MMBtu	600 hours	0.04 tpy
15	Generator Engine	65 kW	Diesel	40 CFR 98, Table C-1	0.003 kg/MMBtu	300 hours	6.0E-04 tpy
21	Breakout Tank 140	55,000 bbl	N/A	N/A	N/A	8,760 hours	0 tpy
22	Generator Engine	800 kWe	Diesel	40 CFR 98, Table C-1	0.003 kg/MMBtu	200 hours	0.005 tpy
						Significant Emissions Units Emissions - CH_4	**2.9 tpy**
Insignificant Emissions Units							
N/A	Heater	0.763 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.007 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.003 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.003 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.003 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.003 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.003 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.003 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.003 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.003 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.005 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.005 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.005 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.005 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.005 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.005 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.005 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.005 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.005 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours	0.01 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours	0.02 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours	0.02 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours	0.02 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours	0.02 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours	0.01 tpy
						Insignificant Emissions Units Emissions - CH_4	**0.2 tpy**
						Total Emissions - CH_4	**3.0 tpy**

Notes:
[1] Parameters and conversions:

Diesel High Heat Value: AP-42 Table 1.3-1 — 139 MMBtu/10^3 gal
Average BSFC, Table 3.4-1, AP-42 — 7,000 Btu/hp-hr

Table D1-22. Potential Annual Emissions (after controls/limitations) Calculations - Nitrous Oxide (N_2O)
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel	Factor	N_2O Emission	Potential	Potential
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	N_2O Emissions [1]
Significant Emissions Units							
8	Heater	20.6 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	0.0001 kg/MMBtu	8,260 hours	0.02 tpy
			Diesel	40 CFR 98, Table C-1	0.0006 kg/MMBtu	500 hours	0.003 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	0.0001 kg/MMBtu	8,260 hours	0.02 tpy
			Diesel	40 CFR 98, Table C-1	0.0006 kg/MMBtu	500 hours	0.003 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	40 CFR 98, Table C-1	0.0001 kg/MMBtu	8,520 hours	0.11 tpy
			Diesel	40 CFR 98, Table C-1	0.0006 kg/MMBtu	240 hours	0.02 tpy
13	Cyclone Turbine	12.9 MW	Natural Gas	40 CFR 98, Table C-1	0.0001 kg/MMBtu	8,760 hours	0.12 tpy
14	Generator Engine	2,250 kW	Diesel	40 CFR 98, Table C-1	0.0006 kg/MMBtu	600 hours	8.36 tpy
15	Generator Engine	65 kW	Diesel	40 CFR 98, Table C-1	0.0006 kg/MMBtu	300 hours	1.2E-04 tpy
21	Breakout Tank 140	55,000 bbl	N/A	N/A	N/A	8,760 hours	0 tpy
22	Generator Engine	800 kWe	Diesel	40 CFR 98, Table C-1	0.0006 kg/MMBtu	200 hours	9.9E-04 tpy
Significant Emissions Units Emissions - N_2O							**8.7 tpy**
Insignificant Emissions Units							
N/A	Heater	0.763 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	7.4E-04 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	7.4E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.9E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.9E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.9E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.9E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.9E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.9E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.9E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.9E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.8E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.8E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.8E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.8E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.8E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.8E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.8E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.8E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.8E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours	0.003 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours	0.003 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours	0.003 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours	0.005 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours	0.005 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours	0.002 tpy
Insignificant Emissions Units Emissions - N_2O							**0.03 tpy**
Total Emissions - N_2O							**8.7 tpy**

Notes:
[1] Parameters and conversions:

Diesel High Heat Value: AP-42 Table 1.3-1	139 MMBtu/10^3 gal
Average BSFC, Table 3.4-1, AP-42	7,000 Btu/hp-hr

D.2 Form D2: Potential to Emit (before controls/limitations) Emissions

Table D2-1. Potential Annual Emissions (before controls/limitations) Summary
Alyeska Pipeline Services Company - Pump Station 4

Potential to Emit	Regulated Air Pollutant Emissions (tons per year) [1,2]							
	NO_X	CO	PM_{10}	$PM_{2.5}$ [4]	VOC	SO_2	HAP	GHG [3]
Significant	1,026.3	119.4	15.1	15.1	29.9	166.6	9.6	198,931
Insignificant	6.0	3.6	0.7	0.7	0.2	4.23	0.73	6,958

Notes:

[1] Regulated air pollutant calculations based on AP-42 emission factors, manufacturer data, and mass balances as shown in accompanying spreadsheets.

[2] See individual emissions unit category HAP emissions calculations for details on methodology and assumptions (electronic copy).

[3] GHG emissions are defined as CO_2e emissions. CO_2e is the summation of CO_2, CH_4, and N_2O, applying the global warming potential for each pollutant.

[4] $PM_{2.5}$ emissions are assumed to be equivalent to PM_{10} emissions.

Table D2-2a. Significant Emissions Unit Inventory
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit				Fuel Type	Maximum Operation
ID	Name	Description	Rating		
8	Heater	Eclipse Therminol	20.6 MMBtu/hr	Natural Gas Diesel	8,760 hours
9	Heater	Eclipse Therminol	20.6 MMBtu/hr	Natural Gas Diesel	8,760 hours
12	Cyclone Turbine	Siemens / SGT-400	12.9 MW	Natural Gas Diesel	8,760 hours
13	Cyclone Turbine	Siemens / SGT-400	12.9 MW	Natural Gas	8,760 hours
14	Generator Engine	Caterpillar / 3516B	2250.0 kW	Diesel	8,760 hours
15	Generator Engine	John Deere	65.0 kW	Diesel	8,760 hours
21	Breakout Tank 140	Crude Oil Storage Tank	150,000 bbl	N/A	8,760 hours
22	Generator Engine	Detroit Diesel / 2000G45TB	800 kW	Diesel	8,760 hours

Table D2-2b. Insignificant Emissions Unit Inventory
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit(s)			Fuel / Material Type	Maximum Operation	Rating	Basis for Insignificance
ID	Description	Make/Model				
N/A	Heater	Burnham	Natural Gas	8,760 hours	0.763 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Burnham	Natural Gas	8,760 hours	0.763 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Ground	Diesel	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(7)
N/A	Heater	Tioga	Diesel	8,760 hours	0.600 MMBtu/hr	18 AAC 50.326(g)(7)
N/A	Heater	Tioga	Diesel	8,760 hours	0.600 MMBtu/hr	18 AAC 50.326(g)(7)
N/A	Heater	Chinook	Diesel	8,760 hours	0.800 MMBtu/hr	18 AAC 50.326(g)(7)
N/A	Heater	Chinook	Diesel	8,760 hours	0.800 MMBtu/hr	18 AAC 50.326(g)(7)
N/A	Heater	Aerotec	Diesel	8,760 hours	0.400 MMBtu/hr	18 AAC 50.326(g)(7)

Table D2-3. Potential Annual Emissions (before controls/limitations) Calculations - Oxides of Nitrogen (NO_X)
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel	Factor	NO_X Emission	Potential	Potential
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	NO_X Emissions [1]
Significant Emissions Units							
8	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	0 hours	0 tpy
			Diesel	AP-42 Table 1.3-1	20 lb/Mgal	8,760 hours [2]	13.0 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	0 hours	0 tpy
			Diesel	AP-42 Table 1.3-1	20 lb/Mgal	8,760 hours [2]	13.0 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	AP-42 Table 3.1-1	0.32 lb/MMBtu	0 hours	0 tpy
			Diesel	AP-42 Table 3.1-1	0.88 lb/MMBtu	8,760 hours [2]	466.7 tpy
13	Cyclone Turbine	12.9 MW	Natural Gas	AP-42 Table 3.1-1	0.32 lb/MMBtu	8,760 hours	169.7 tpy
14	Generator Engine	2,250 kW	Diesel	Manufacturer's Data	71 lb/hr	8,760 hours	311.0 tpy
15	Generator Engine	65 kW	Diesel	Tier 2 Standard [3]	7.5 g/kW-hr	8,760 hours	4.7 tpy
21	Breakout Tank 140	150,000 bbl	N/A	N/A	N/A	8,760 hours	0 tpy
22	Generator Engine	800 kW	Diesel	Manufacturer's Data	11.0 lb/hr	8,760 hours	48.2 tpy
Significant Emissions Units Emissions - NO_X							**1,026.3 tpy**
Insignificant Emissions Units							
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.3 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.3 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	AP-42 Table 1.3-1	20 lb/Mgal	8,760 hours	0.3 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-1	20 lb/Mgal	8,760 hours	0.4 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-1	20 lb/Mgal	8,760 hours	0.4 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-1	20 lb/Mgal	8,760 hours	0.5 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-1	20 lb/Mgal	8,760 hours	0.5 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	AP-42 Table 1.3-1	20 lb/Mgal	8,760 hours	0.3 tpy
Insignificant Emissions Units Emissions - NO_X							**6.0 tpy**
Total Emissions - NO_X							**1,032.2 tpy**

Notes:
[1] Parameters and Conversions:
- Natural Gas High Heat Value: AP-42 Table 1.4-1 — 1,020 Btu/scf
- Diesel High Heat Value: AP-42 Table 1.3-1 — 139 MMBtu/10^3 gal
- Average BSFC, Table 3.4-1, AP-42 — 7,000 Btu/hp-hr

[2] Assumed worst case emissions scenario with maximum operation on diesel for EU IDs 8,9 and 12.
[3] 40 CFR Appendix I to Part 1039(b)

Table D2-4. Potential Annual Emissions (before controls/limitations) Calculations - Carbon Monoxide (CO)
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel	Factor	CO Emission	Potential	Potential
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	CO Emissions [1]
Significant Emissions Units							
8	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours [2]	7.4 tpy
			Diesel	AP-42 Table 1.3-1	5 lb/Mgal	0 hours	0.0 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours [2]	7.4 tpy
			Diesel	AP-42 Table 1.3-1	5 lb/Mgal	0 hours	0.0 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	AP-42 Table 3.1-1	0.082 lb/MMBtu	8,760 hours [2]	43.5 tpy
			Diesel	AP-42 Table 3.1-1	0.0033 lb/MMBtu	0 hours	0 tpy
13	Cyclone Turbine	12.9 MW	Natural Gas	AP-42 Table 3.1-1	0.082 lb/MMBtu	8,760 hours	43.5 tpy
14	Generator Engine	2,250 kW	Diesel	Manufacturer's Data	2 lb/hr	8,760 hours	9.6 tpy
15	Generator Engine	65 kW	Diesel	Tier 2 Standard [3]	5.0 g/kW-hr	8,760 hours	3.1 tpy
21	Breakout Tank 140	150,000 bbl	N/A	N/A	N/A	8,760 hours	0 tpy
22	Generator Engine	800 kW	Diesel	Manufacturer's Data	1.1 lb/hr	8,760 hours	4.8 tpy
						Significant Emissions Units Emissions - CO	**119.4 tpy**
Insignificant Emissions Units							
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.3 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.3 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	AP-42 Table 1.3-1	5 lb/Mgal	8,760 hours	0.08 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-1	5 lb/Mgal	8,760 hours	0.09 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-1	5 lb/Mgal	8,760 hours	0.09 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-1	5 lb/Mgal	8,760 hours	0.1 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-1	5 lb/Mgal	8,760 hours	0.1 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	AP-42 Table 1.3-1	5 lb/Mgal	8,760 hours	0.06 tpy
						Insignificant Emissions Units Emissions - CO	**3.6 tpy**
						Total Emissions - CO	**123.1 tpy**

Notes:
[1] Parameters and Conversions:

Natural Gas High Heat Value: AP-42 Table 1.4-1, 3.1-1	1,020	Btu/scf
Diesel High Heat Value: AP-42 Table 1.3-1	139	MMBtu/10^3 gal
Average BSFC, Table 3.4-1, AP-42	7,000	Btu/hp-hr

[2] Assumed worst case emissions scenario with maximum operation on natural gas for EU IDs 8, 9, and 12.
[3] 40 CFR Appendix I to Part 1039(b)

Table D2-5. Potential Annual Emissions (before controls/limitations) Calculations - Particulate Matter Less Than 10 Microns (PM_{10})
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel	Factor	PM_{10} Emission	Potential	Potential
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	PM_{10} Emissions [1]
Significant Emissions Units							
8	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	0 hours	0 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0 tpy
			Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	8,760 hours [2]	1.3 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0.8 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	0 hours	0 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0 tpy
			Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	8,760 hours [2]	1.3 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0.8 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	AP-42 Table 3.1-2a (filterable)	1.9E-03 lb/MMBtu	8,760 hours [2]	1.0 tpy
				AP-42 Table 3.1-2a (condensible)	4.7E-03 lb/MMBtu		2.5 tpy
			Diesel	AP-42 Table 3.1-2a (filterable)	4.3E-03 lb/MMBtu	0 hours	0 tpy
				AP-42 Table 3.1-2a (condensible)	7.2E-03 lb/MMBtu		0 tpy
13	Cyclone Turbine	12.9 MW	Natural Gas	AP-42 Table 3.1-2a (filterable)	1.9E-03 lb/MMBtu	8,760 hours	1.0 tpy
				AP-42 Table 3.1-2a (condensible)	4.7E-03 lb/MMBtu		2.5 tpy
14	Generator Engine	2,250 kW	Diesel	Manufacturer's Data	0.6 lb/hr	8,760 hours	2.6 tpy
15	Generator Engine	65 kW	Diesel	AP-42 Table 3.3-1	3.1E-01 lb/MMBtu	8,760 hours	0.8 tpy
21	Breakout Tank 140	150,000 bbl	N/A	N/A	N/A	8,760 hours	0 tpy
22	Generator Engine	800 kW	Diesel	Manufacturer's Data	0.09 lb/hr	8,760 hours	0.4 tpy
					Significant Emissions Units Emissions - PM_{10}		**15.1 tpy**
Insignificant Emissions Units							
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.006 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.02 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.006 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.02 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.300 #REF!	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.3-1 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.3-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.3-1 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.3-2 (condensable)	5.7 lb/MMscf		0.012 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.3-1 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.3-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.3-1 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.3-2 (condensable)	5.7 lb/MMscf		0.012 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.3-1 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.3-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	8,760 hours	0.03 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0.02 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	8,760 hours	0.04 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0.02 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	8,760 hours	0.04 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0.02 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	8,760 hours	0.05 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0.03 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	8,760 hours	0.05 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0.03 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	8,760 hours	0.03 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0.02 tpy
					Insignificant Emissions Units Emissions - PM_{10}		**0.7 tpy**
					Total Emissions - PM_{10}		**15.8 tpy**

Notes:
[1] Parameters and Conversions:

Natural Gas High Heat Value: AP-42 Table 1.4-	1,020	Btu/scf
Diesel High Heat Value: AP-42 Table 1.3-1	139	MMBtu/10^3 gal
Average BSFC, Table 3.4-1, AP-42	7,000	Btu/hp-hr

[2] Assumed worst case emissions scenario with maximum operation on diesel for EU IDs 8 and 9 and natural gas for EU ID 12.

Table D2-6a. Potential Annual Emissions (before controls/limitations) Calculations - Volatile Organic Compunds (VOC)
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel	Factor	VOC Emission	Potential	Potential
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	VOC Emissions [1]
Significant Emissions Units							
8	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,760 hours	0.5 tpy
			Diesel	AP-42 Table 1.3-3	0.252 lb/Mgal	0 hours [2]	0 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,760 hours	0 tpy
			Diesel	AP-42 Table 1.3-3	0.252 lb/Mgal	8,760 hours [2]	0.2 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	AP-42 Table 3.1-2a	2.1E-03 lb/MMBtu	8,760 hours [2]	1.1 tpy
			Diesel	AP-42 Table 3.1-2a	4.1E-04 lb/MMBtu	0 hours	0 tpy
13	Cyclone Turbine	12.9 MW	Natural Gas	AP-42 Table 3.1-2a	2.1E-03 lb/MMBtu	8,760 hours	1.1 tpy
14	Generator Engine	2,250 kW	Diesel	Manufacturer's Data	1 lb/hr	8,760 hours	4.4 tpy
15	Generator Engine	65 kW	Diesel	AP-42 Table 3.3-1	2.47E-03 lb/hp-hr	8,760 hours	0.9 tpy
21	Breakout Tank 140	150,000 bbl	N/A	N/A	N/A	8,760 hours	20.1 tpy
22	Generator Engine	800 kW	Diesel	Manufacturer's Data	0.3 lb/hr	8,760 hours	1.2 tpy
						Significant Emissions Units Emissions - VOC	**29.9 tpy**
Insignificant Emissions Units							
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,760 hours	0.02 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,760 hours	0.02 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	AP-42 Table 1.3-3	0.252 lb/Mgal	8,760 hours	0.004 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-3	0.252 lb/Mgal	8,760 hours	0.005 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-3	0.252 lb/Mgal	8,760 hours	0.005 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-3	0.252 lb/Mgal	8,760 hours	0.006 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-3	0.252 lb/Mgal	8,760 hours	0.006 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	AP-42 Table 1.3-3	0.252 lb/Mgal	8,760 hours	0.003 tpy
						Insignificant Emissions Units Emissions - VOC	**0.2 tpy**
						Total Emissions - VOC	**30.2 tpy**

Notes:
[1] Parameters and Conversions:

Natural Gas High Heat Value: AP-42 Table 1.4-2, 3.'	1,020	Btu/scf
Diesel High Heat Value: AP-42 Table 1.3-1	139	$MMBtu/10^3$ gal
Average BSFC, Table 3.4-1, AP-42	7,000	Btu/hp-hr

[2] Assumed worst case emissions scenario with maximum operation on diesel for EU IDs 8, 9, and 12.

Table D2-6b. Potential Annual Emissions (before controls/limitations) Calculations - Tank VOC
Alyeska Pipeline Services Company - Pump Station 4

Tank Description	Breakout Tank 140
Orientation	Vertical
Contents	Crude Oil
Capacity (gallons)	2,310,000
Diameter, D (ft)	116
Radium, R_S (ft)	58
Shell Height, H_S (ft)	32
Average Liquid Height (H_L)	28.0
Maximum Liquid Height (H_{LX})	31
Crude Throughput (bbl/yr)	55000
Color	Green
Paint Condition	Average
Roof Type	Cone
Slope, S_R (ft/ft)	0.125
Standing Loss (L_S) Calculations	
Vapor Space Expansion Factor, K_E	0.016
Vapor Space Outage, H_{VO} (ft)	6.42
Average Daily Ambient Temperature, T_{AA} (°R)	471.70
Liquid Bulk Temperature, T_B (°R)	471.71
Average Daily Liquid Surface Temperature, T_{LA} (°R)	471.73
Average Vapor Temperature, T_V (°R)	471.75
Vented Vapor Density, K_S	0.1665
Stock Vapor Density, W_V (lb/ft^3)	1.45E-01
Standing Loss, L_S (lb/yr)	**9763.10**
Working Loss (L_W) Calculations	
Tank Maximum Liquid Volume, V_{LX} (ft^3)	327,618
Number of Turnovers per Year, N	1.0
Turnover Factor, K_N	1.0
Working Loss, L_W (lb/yr)	**30360**
Total VOCs (tpy)	**20.1**

Meteorological Inputs (Prudhoe Bay, AK):

T_{AX} =	18.1 F	478.1 R
T_{AN} =	5.3 F	465.3 R
a =	0.25	White, Average
I =	18.5	Btu/ft^2-d

Constants:

K_P (crude)=	0.75	
M_V (crude)=	50	lb/lb-mol
P_{va} (crude)=	14.72	psi

Table D2-7. Potential Annual Emissions (before controls/limitations) Calculations - Sulfur Dioxide (SO_2)
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel	Factor	Maximum Fuel	SO_2 Emission	Potential	Potential
ID	Description	Rating/Capacity	Type	Reference	Sulfur Content [1,2]	Factor	Operation	SO_2 Emissions [3]
Significant Emissions Units								
8	Heater	20.6 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	0 hours	0 tpy
			Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8,760 hours [4]	18.4 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	0 hours	0 tpy
			Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8,760 hours [4]	18.4 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	0 hours	0 tpy
			Diesel		0.2 wt.% S	2.84E-02 lb/gal	8,760 hours [4]	108.4 tpy
13	Cyclone Turbine	12.9 MW	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	1.9 tpy
14	Generator Engine	2,250 kW	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8,760 hours	18.9 tpy
15	Generator Engine	65 kW	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8,760 hours	0.5 tpy
21	Breakout Tank 140	150,000 bbl	N/A	N/A	N/A	N/A	8,760 hours	N/A
22	Generator Engine	800 kW	Diesel	Manufacturer's Data	0.0015 wt.% S	2.13E-04 lb/gal	8,760 hours	0.1 tpy
							Significant Emissions Units Emissions - SO_2	**166.6 tpy**
Insignificant Emissions Units								
N/A	Heater	0.763 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.08 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.08 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8,760 hours	0.45 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8,760 hours	0.54 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8,760 hours	0.54 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8,760 hours	0.72 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8,760 hours	0.72 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8,760 hours	0.36 tpy
							Insignificant Emissions Units Emissions - SO_2	**4.2 tpy**
							Total Emissions - SO_2	**170.9 tpy**

Notes:

[1] Per AQ0074TVP04 Condition 19.1 - Limit H_2S concentration of fuel gas to no greater than 150 ppmv

[2] Per AQ0074TVP04 Condition 19.2 - Limit fuel sulfur concentration of diesel fuel to no greater than 0.20 percent by weight

[3] Parameters and conversions:

Density of diesel fuel.	7.10	lb/gal
Natural Gas High Heat Value: AP-42 Table 1.4-2, 3.1-2a	1,020	Btu/scf
Diesel average heat value: Table 3.1-2a, AP-42.	139	MMBtu/10^3 gallons
Average BSFC, Table 3.4-1, AP-42	7,000	Btu/hp-hr

[4] Assumed worst case emissions scenario with maximum operation on diesel for EU IDs 8, 9, and 12.

Table D2-8. Potential Annual Emissions (before controls/limitations) Calculations - Hazardous Air Pollutants (HAP) Summary
Alyeska Pipeline Services Company - Pump Station 4

Hazardous Air Pollutant	Diesel Heaters	Natural Gas Turbines	Diesel Turbines	Liquid Fugitives	Gas Fugitives	Diesel Engines <600 hp	Diesel Engines >600 hp	Insignificant Units NG [2]	Insignificant Units Diesel [2]	Total HAP Emissions
Acetaldehyde	----	2.12E-02	----	----	----	2.05E-03	3.16E-03	----	----	2.64E-02
Acrolein	----	3.39E-03	----	----	----	2.47E-04	9.88E-04	----	----	4.63E-03
Benzene	3.79E-02	6.36E-03	2.92E-02	1.49E-01	1.72E-02	2.49E-03	9.73E-02	7.60E-05	3.40E-03	3.42E-01
1,3 Butadiene	----	2.28E-04	8.49E-03	----	----	----	----	----	----	8.71E-03
Dichlorobenzene	----	----	----	----	----	----	----	4.34E-05	----	4.34E-05
Ethyl benzene	1.15E-02	1.70E-02	----	9.00E-02	----	----	----	----	1.03E-03	1.19E-01
Formaldehyde	5.96E+00	3.77E-01	1.49E-01	----	----	3.15E-03	9.89E-03	2.71E-03	5.35E-01	7.03E+00
Hexane	----	----	----	----	----	----	----	6.51E-02	----	6.51E-02
Polycyclic aromatic compounds(PAH)	2.60E-01	1.17E-03	2.12E-02	7.20E-02	----	4.49E-04	2.65E-02	2.44E-05	2.34E-02	4.05E-01
Polycyclic Organic Matter (POM)	2.60E-01	----	----	7.20E-02	----	4.49E-04	2.65E-02	2.44E-05	2.34E-02	3.83E-01
Acenaphthene	3.81E-03	----	----	----	----	3.79E-06	5.87E-04	6.51E-08	3.42E-04	4.74E-03
Acenaphthylene	4.57E-02	----	----	----	----	1.35E-05	1.16E-03	6.51E-08	4.10E-03	5.09E-02
Anthracene	2.20E-04	----	----	----	----	5.00E-06	1.54E-04	8.68E-08	1.98E-05	3.99E-04
Benzo(a)anthracene	7.24E-04	----	----	----	----	4.49E-06	7.80E-05	----	6.50E-05	8.71E-04
Benzo(a)pyrene	----	----	----	----	----	5.02E-07	3.22E-05	4.34E-08	----	3.28E-05
Benzo(b)fluoranthene	----	----	----	----	----	2.65E-07	1.39E-04	6.51E-08	----	1.40E-04
Benzo(g,h,i)perylene	4.08E-04	----	----	----	----	----	----	4.34E-08	----	4.08E-04
Benzo(g,h,l)perylene	----	----	----	----	----	1.31E-06	6.97E-05	----	----	7.10E-05
Benzo(k)fluoranthene	----	----	----	----	----	4.14E-07	2.73E-05	6.51E-08	----	2.78E-05
Chrysene	4.29E-04	----	----	----	----	9.43E-07	1.92E-04	6.51E-08	----	6.22E-04
Dibenz(a,h)anthracene	3.01E-04	----	----	----	----	1.56E-06	4.34E-05	----	----	3.46E-04
7,12-Dimethylbenz(a)anthracene	----	----	----	----	----	----	----	5.79E-07	----	5.79E-07
Fluoranthene	8.73E-04	----	----	----	----	2.03E-05	5.05E-04	1.09E-07	----	1.40E-03
Fluorene	8.07E-04	----	----	----	----	7.80E-05	1.61E-03	1.01E-07	----	2.49E-03
Indeno(1,2,3-cd)pyrene	3.86E-04	----	----	----	----	1.00E-06	5.19E-05	6.51E-08	----	4.39E-04
2-Methylnapthalene	----	----	----	----	----	----	----	8.68E-07	----	8.68E-07
3-Methylcholanthrene	----	----	----	----	----	----	----	6.51E-08	----	6.51E-08
Naphthalene	2.04E-01	----	----	7.20E-02	----	2.27E-04	1.63E-02	2.21E-05	----	2.92E-01
Phenanthrene	1.89E-03	----	----	----	----	7.86E-05	5.12E-03	----	----	7.09E-03
Pyrene	7.67E-04	----	----	----	----	1.28E-05	4.65E-04	----	----	1.24E-03
Propylene Oxide	----	1.54E-02	----	----	----	----	----	----	----	1.54E-02
Toluene	1.12E+00	6.89E-02	----	3.78E-01	1.01E-01	1.09E-03	3.52E-02	----	1.00E-01	1.80E+00
Xylenes (isomers and mixture)	----	3.39E-02	----	----	----	7.62E-04	2.42E-02	----	----	5.89E-02
Arsenic	----	----	5.83E-03	----	----	----	----	----	----	5.83E-03
Beryllium	----	----	1.64E-04	----	----	----	----	----	----	1.64E-04
Cadmium	----	----	2.55E-03	----	----	----	----	----	----	2.55E-03
Chromium	----	----	5.83E-03	----	----	----	----	----	----	5.83E-03
Cobalt	----	----	----	----	----	----	----	----	----	----
Lead	----	----	7.43E-03	----	----	----	----	----	----	7.43E-03
Manganese	----	----	4.19E-01	----	----	----	----	----	----	4.19E-01
Mercury	----	----	6.36E-04	----	----	----	----	----	----	6.36E-04
Nickel	----	----	2.44E-03	----	----	----	----	----	----	2.44E-03
Selenium	----	----	1.33E-02	----	----	----	----	----	----	1.33E-02
Total HAPs - Maximum Individual HAP	**5.96E+00**	**3.77E-01**	**4.19E-01**	**3.78E-01**	**1.01E-01**	**3.15E-03**	**9.73E-02**	**6.51E-02**	**5.35E-01**	**7.03E+00**
Total VOC HAP Emissions	**7.38E+00**	**5.44E-01**	**2.07E-01**	**6.89E-01**	**1.18E-01**	**1.02E-02**	**1.97E-01**	**6.80E-02**	**6.63E-01**	**1.03E+01**
Total HAPs Emissions	**7.38E+00**	**5.44E-01**	**6.65E-01**	**6.89E-01**	**1.18E-01**	**1.02E-02**	**1.97E-01**	**6.80E-02**	**6.63E-01**	**1.03E+01**

Notes:

[1] HAP emissions from the fuel storage tanks are considered negligible.
[2] The HAP emissions from insignificant natural gas heaters are included under Table D2-16 IEU NG Heaters and D2-17 IEU Diesel Heaters.

Table D2-9. Potential Annual Emissions (before controls/limitations) Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Diesel Fired Heaters

Potential Total Heat Input for Emissions Units: 360,912 MMBtu/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations			
CAS No.	**Chemical Name**	**Emission Factor [2]**		**Estimated Emissions [3]**	
N/A	Arsenic Compounds	4.00E-06	lb/MMBtu	7.22E-04	tpy
71-43-2	Benzene	2.10E-04	lb/MMBtu	0.04	tpy
N/A	Beryllium Compounds	3.00E-06	lb/MMBtu	5.41E-04	tpy
N/A	Cadmium Compounds	3.00E-06	lb/MMBtu	5.41E-04	tpy
N/A	Chromium Compounds	3.00E-06	lb/MMBtu	5.41E-04	tpy
100-41-4	Ethyl benzene	6.36E-05	lb/MMBtu	0.01	tpy
50-00-0	Formaldehyde	3.30E-02	lb/MMBtu	6.0	tpy
N/A	Lead Compounds	9.00E-06	lb/MMBtu	0.002	tpy
N/A	Manganese Compounds	6.00E-06	lb/MMBtu	0.001	tpy
N/A	Mercury Compounds	3.00E-06	lb/MMBtu	5.41E-04	tpy
N/A	Nickel Compounds	3.00E-06	lb/MMBtu	5.41E-04	tpy
N/A	Selenium Compounds	1.50E-05	lb/MMBtu	0.003	tpy
108-88-3	Toluene	6.20E-03	lb/MMBtu	1.1	tpy
71-55-6	1,1,1-Trichloroethane	2.36E-04	lb/MMBtu	0.04	tpy
1330-20-7	Xylenes	1.09E-04	lb/MMBtu	0.02	tpy
N/A	Polycyclic Organic Matter (POM)			0.3	tpy
N/A	Polycyclic aromatic compounds(PAH)			0.3	tpy
208-96-8	Acenaphthene	2.11E-05	lb/MMBtu	0.004	tpy
83-32-9	Acenaphthylene	2.53E-04	lb/MMBtu	0.05	tpy
120-12-7	Anthracene	1.22E-06	lb/MMBtu	2.20E-04	tpy
56-55-3	Benzo(a)anthracene	4.01E-06	lb/MMBtu	7.24E-04	tpy
205-99-2	Benzo(b,k)fluoranthene	1.48E-06	lb/MMBtu	2.67E-04	tpy
191-24-2	Benzo(g,h,i)perylene	2.26E-06	lb/MMBtu	4.08E-04	tpy
218-01-9	Chrysene	2.38E-06	lb/MMBtu	4.29E-04	tpy
53-70-3	Dibenz(a,h)anthracene	1.67E-06	lb/MMBtu	3.01E-04	tpy
206-44-0	Fluoranthene	4.84E-06	lb/MMBtu	8.73E-04	tpy
86-73-7	Fluorene	4.47E-06	lb/MMBtu	8.07E-04	tpy
193-39-5	Indeno(1,2,3-cd)pyrene	2.14E-06	lb/MMBtu	3.86E-04	tpy
91-20-3	Naphthalene	1.13E-03	lb/MMBtu	0.2	tpy
85-01-8	Phenanthrene	1.05E-05	lb/MMBtu	0.002	tpy
129-00-0	Pyrene	4.25E-06	lb/MMBtu	7.67E-04	tpy
		Total Potential HAP Emissions:		**7.5**	**tpy**

Notes:

[1] Total fuel use based on maximum full-time operation or permit-limited operation as noted below.

EU ID 11	Heater		20.6	MMBtu/hr
			8,760	hr/yr
		Potential Heat Input:	180,456	MMBtu/yr
EU ID 12	Heater		20.6	MMBtu/hr
			8,760	hr/yr
		Potential Heat Input:	180,456	MMBtu/yr
		Total Potential Heat Input:	**360,912**	**MMBtu/yr**

[2] Reference: AP-42, Tables 1.3-9 and 1.3-10

[3] Diesel average heat value: Table 1.3-1, AP-42. 139 MMBtu/1000 gal

Table D2-10. Potential Annual Emissions (before controls/limitations) Calculations - Hazardous Air Pollutant (HAP) Emissions
Alyeska Pipeline Services Company - Pump Station 4
Natural Gas Fired Turbines

1,060,769 MMBtu/yr [1]

CAS No.	Chemical Name	AP-42 Emission Factor [2] (Source Category Emission Calculations)	Estimated Emissions (Source Category Emission Calculations)
	1,3 Butadiene	4.30E-07 lb/MMBtu	2.28E-04 tpy
	Acetaldehyde	4.00E-05 lb/MMBtu	0.02 tpy
	Acrolein	6.40E-06 lb/MMBtu	0.00 tpy
71-43-2	Benzene	1.20E-05 lb/MMBtu	0.006 tpy
100-41-4	Ethyl benzene	3.20E-05 lb/MMBtu	0.02 tpy
50-00-0	Formaldehyde	7.10E-04 lb/MMBtu	0.38 tpy
	Napthalene	1.30E-06 lb/MMBtu	6.89E-04 tpy
	Polycyclic aromatic compounds(PAH)	2.20E-06 lb/MMBtu	0.001 tpy
	Propylene Oxide	2.90E-05 lb/MMBtu	0.02 tpy
108-88-3	Toluene	1.30E-04 lb/MMBtu	0.07 tpy
1330-20-7	Xylenes (isomers and mixture)	6.40E-05 lb/MMBtu	0.03 tpy
			0.5 tpy

Notes:
[1] Total fuel use based on maximum full-time operation as noted below.

EU ID 12	Cyclone Turbine	121.1	MMBtu/hr
		0	hr/yr
	Potential Heat Input:	0	MMBtu/yr
EU ID 13	Cyclone Turbine	121.1	MMBtu/hr
		8,760	hr/yr
	Potential Heat Input:	1,060,769	MMBtu/yr
	Total Potential Heat Input:	**1,060,769**	**MMBtu/yr**
	Average BSFC, Table 3.4-1, AP-42	7,000	Btu/hp-hr

[2] Reference: AP-42, Tables 3.1-3
[3] Assumed worst case senario of operation on diesel fuel for EU ID 12

Table D2-11. Potential Annual Emissions (before controls/limitations) Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Diesel Fired Turbines

1,060,769 MMBtu/yr [1]

CAS No.	Chemical Name	Source Category Emission Calculations AP-42 Emission Factor [2]	 Estimated Emissions
	1,3 Butadiene	1.60E-05 lb/MMBtu	8.49E-03 tpy
71-43-2	Benzene	5.50E-05 lb/MMBtu	2.92E-02 tpy
50-00-0	Formaldehyde	2.80E-04 lb/MMBtu	1.49E-01 tpy
	Napthalene	3.50E-05 lb/MMBtu	1.86E-02 tpy
	Polycyclic aromatic compounds(PAH)	4.00E-05 lb/MMBtu	2.12E-02 tpy
	Arsenic	1.10E-05 lb/MMBtu	5.83E-03 tpy
	Beryllium	3.10E-07 lb/MMBtu	1.64E-04 tpy
	Cadmium	4.80E-06 lb/MMBtu	2.55E-03 tpy
	Chromium	1.10E-05 lb/MMBtu	5.83E-03 tpy
	Lead	1.40E-05 lb/MMBtu	7.43E-03 tpy
	Manganese	7.90E-04 lb/MMBtu	4.19E-01 tpy
	Mercury	1.20E-06 lb/MMBtu	6.36E-04 tpy
	Nickel	4.60E-06 lb/MMBtu	2.44E-03 tpy
	Selenium	2.50E-05 lb/MMBtu	1.33E-02 tpy
		Total Potential HAP Emissions:	**0.7 tpy**

Notes:
[1] Total fuel use based on maximum full-time operation as noted below.

EU ID 12	Cyclone Turbine	121	MMBtu/hr
		8,760	hr/yr
	Potential Heat Input:	1,060,769	MMBtu/yr
	Total Potential Heat Input:	**1,060,769**	**MMBtu/yr**
	Average BSFC, Table 3.4-1, AP-42	7,000	Btu/hp-hr

[2] Reference: AP-42, Tables 3.1-4, 3.1-5

Table D2-12. Potential Annual Emissions (before controls/limitations) Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Piping Fugitives - Light Liquid Service

1. Assume that the TOC emissions (losses) are determined from emission factors in Protocol for Equipment Leak Estimates, EPA-453-95-017, November 1995.

2. Based on this protocol, and a TAPs facilities fugitive emissions study conducted by Alyeska in 1998, the potential TOC emissions for PS 4 are estimated to be:
   45 tpy (Light Liquid Service)

3. Conservatively assuming that the light liquid piping leaks are all associated with crude, the individual component emission rates (losses) are then determined using the crude liquid phase weight fractions as determined by Core Laboratories.

Calculation of Component Emission Rates (Losses) - Light Liquids				
Component	Component Weight Fraction in Crude (wt%/100)	Total Light Liquid TOC Fugitive Losses (tpy)	Component Emission Rate/Loss (tpy)	Total HAP Light Liquid Fugitive Emissions/Losses (tpy)
Methane	0	45	0.0	N/A
Ethane	0.0002	45	0.01	N/A
Propane	0.003	45	0.1	N/A
Isobutane	0.0044	45	0.2	N/A
N-Butane	0.0152	45	0.7	N/A
1,3 Butadiene	0	45	0	0
Isopentane	0.0088	45	0.4	N/A
N-Pentane	0.0127	45	0.6	N/A
N-Hexane	0.0104	45	0.5	0.47
Hexanes	0.0118	45	0.5	N/A
Benzene	0.0033	45	0.1	0.15
Heptanes	0.0392	45	1.8	N/A
2,2,4 Trimethylpentane	0	45	0	0
Toluene	0.0084	45	0.4	0.38
Octanes	0.0464	45	2.1	N/A
Ethyl Benzene	0.002	45	0.1	0.09
Xylenes	0.0095	45	0.4	0.43
Isopropylbenzene	0.0005	45	0.02	0.02
Nonanes	0.031	45	1.4	N/A
Naphthalene	0.0016	45	0.07	0.07
Decanes+	0.7916	45	35.6	N/A
Total Potential HAP Emissions:	**1.0**		**45**	**1.6**

Table D2-13. Potential Annual Emissions (before controls/limitations) Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Piping Fugitives - Gas/Vapor Service

1. Assume that the TOC emissions (losses) are determined from emission factors in Protocol for Equipment Leak Estimates, EPA-453-95-017, November 1995.

2. Based on this protocol, and a TAPs facilities fugitive emissions study conducted by Alyeska in 1998, the potential TOC emissions for PS 4 are estimated to be:
176 tpy (Gas/Vapor Service)

3. Assuming that the gas/vapor piping leaks are all associated with fuel gas, the individual component emission rates (losses) are then determined using the weight fractions previously calculated.

Calculation of Component Emission Rates (Losses) - Gas/Vapor Service					
Component	Component Weight Fraction in Fuel Gas	Normalized Component Weight Fraction in Fuel Gas	Total Gas/Vapor TOC Fugitive Losses (tpy)	Component Emission Rate/Loss (tpy)	Total HAP Fuel Gas Fugitive Emissions/Losses (tpy)
Methane	0.56826	0.77321	176	136.1	N/A
Ethane	0.07875	0.10715	176	18.9	N/A
Propane	0.04214	0.05734	176	10.1	N/A
Isobutane	0.03578	0.04869	176	8.6	N/A
N-Butane	0.00614	0.00836	176	1.5	N/A
1,3 Butadiene	0	0	176	0	0
Isopentane	0.00099	0.00135	176	0.24	N/A
N-Pentane	0.00099	0.00135	176	0.24	N/A
N-Hexane	0.00020	0.00027	176	0.05	0.05
Hexanes+	0.00118	0.00161	176	0.28	N/A
Benzene	0.00007	0.00010	176	0.02	0.02
2,2,4 Trimethylpentane	0	0	176	0	0
Toluene	0.00042	0.00058	176	0.10	0.10
Ethyl Benzene	0	0	176	0	0
Xylenes	0	0	176	0	0
Isopropylbenzene	0	0	176	0	0
Napthalene	0	0	176	0	0
otal Potential HAP Emissions:	**0.73**	**1.0**		**176**	**0.2**

Notes:
1. The component weight fractions in the fuel gas were normalized to eliminate the non-organic components N_2 and CO_2.

Table D2-14. Potential Annual Emissions (before controls/limitations) Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Diesel Engines Less Than 600 Horsepower

Maximum Total Heat Input: 5345.0 MMBtu/yr [1]

Section 112 Hazardous Air Pollutants			Source Category Emission Calculations	
No.	**CAS No.**	**Chemical Name**	**Emission Factor [2]**	**Estimated Emissions**
1	75070	Acetaldehyde	7.67E-04 lb/MMBtu	2.05E-03 tpy
6	107028	Acrolein	9.25E-05 lb/MMBtu	2.47E-04 tpy
15	71432	Benzene	9.33E-04 lb/MMBtu	2.49E-03 tpy
23	106990	1,3-Butadiene	3.91E-05 lb/MMBtu	1.04E-04 tpy
87	5000	Formaldehyde	1.18E-03 lb/MMBtu	3.15E-03 tpy
152	108883	Toluene	4.09E-04 lb/MMBtu	1.09E-03 tpy
169	1330207	Xylenes (isomers and mixture)	2.85E-04 lb/MMBtu	7.62E-04 tpy
187	N/A	Polycyclic Organic Matter (POM)	1.68E-04 lb/MMBtu	4.49E-04 tpy
		Polycyclic aromatic compounds(PAH)		4.49E-04 tpy
119	91203	Naphthalene	8.48E-05 lb/MMBtu	2.27E-04 tpy
		Acenaphthylene	5.06E-06 lb/MMBtu	1.35E-05 tpy
		Acenaphthene	1.42E-06 lb/MMBtu	3.79E-06 tpy
		Fluorene	2.92E-05 lb/MMBtu	7.80E-05 tpy
		Phenanthrene	2.94E-05 lb/MMBtu	7.86E-05 tpy
		Anthracene	1.87E-06 lb/MMBtu	5.00E-06 tpy
		Fluoranthene	7.61E-06 lb/MMBtu	2.03E-05 tpy
		Pyrene	4.78E-06 lb/MMBtu	1.28E-05 tpy
		Benzo(a)anthracene	1.68E-06 lb/MMBtu	4.49E-06 tpy
		Chrysene	3.53E-07 lb/MMBtu	9.43E-07 tpy
		Benzo(b)fluoranthene	9.91E-08 lb/MMBtu	2.65E-07 tpy
		Benzo(k)fluoranthene	1.55E-07 lb/MMBtu	4.14E-07 tpy
		Benzo(a)pyrene	1.88E-07 lb/MMBtu	5.02E-07 tpy
		Indeno(1,2,3-cd)pyrene	3.75E-07 lb/MMBtu	1.00E-06 tpy
		Dibenz(a,h)anthracene	5.83E-07 lb/MMBtu	1.56E-06 tpy
		Benzo(g,h,l)perylene	4.89E-07 lb/MMBtu	1.31E-06 tpy
			Total Potential HAP Emissions:	**0.01 tpy**

Notes:
[1] Total fuel use based on maximum full-time operation as noted below.

EU ID 15 Generator Engine	0.6 MMBtu/hr
	8,760 hrs
Potential Heat Input:	5,345 MMBtu/yr
Total Potential Heat Input:	**5,345 MMBtu/yr**
Engines heat rate:	7,000 Btu/hp-hr

[2] Reference: AP-42, Table 3.3-2.

Table D2-15. Potential Annual Emissions (before controls/limitations) Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Diesel Engines Greater Than or Equal to 600 Horsepower

Maximum Total Heat Input: 250,801.9 MMBtu/yr [1]

CAS No.	Chemical Name	Source Category Emission Calculations: Emission Factor [2]		Estimated Emissions	
75-07-0	Acetaldehyde	2.52E-05	lb/MMBtu	3.16E-03	tpy
107-02-8	Acrolein	7.88E-06	lb/MMBtu	9.88E-04	tpy
71-43-2	Benzene	7.76E-04	lb/MMBtu	9.73E-02	tpy
50-00-0	Formaldehyde	7.89E-05	lb/MMBtu	9.89E-03	tpy
108-88-3	Toluene	2.81E-04	lb/MMBtu	3.52E-02	tpy
1330-20-7	Xylenes (isomers and mixture)	1.93E-04	lb/MMBtu	2.42E-02	tpy
N/A	Polycyclic Organic Matter (POM)	2.12E-04	lb/MMBtu	2.65E-02	tpy
	Polycyclic aromatic compounds(PAH)			2.65E-02	tpy
	Acenaphthene	4.68E-06	lb/MMBtu	5.87E-04	tpy
	Acenaphthylene	9.23E-06	lb/MMBtu	1.16E-03	tpy
	Anthracene	1.23E-06	lb/MMBtu	1.54E-04	tpy
	Benzo(a)anthracene	6.22E-07	lb/MMBtu	7.80E-05	tpy
	Benzo(b)fluoranthene	1.11E-06	lb/MMBtu	1.39E-04	tpy
	Benzo(k)fluoranthene	2.18E-07	lb/MMBtu	2.73E-05	tpy
	Benzo(a)pyrene	2.57E-07	lb/MMBtu	3.22E-05	tpy
	Benzo(g,h,l)perylene	5.56E-07	lb/MMBtu	6.97E-05	tpy
	Chrysene	1.53E-06	lb/MMBtu	1.92E-04	tpy
	Dibenz(a,h)anthracene	3.46E-07	lb/MMBtu	4.34E-05	tpy
	Fluoranthene	4.03E-06	lb/MMBtu	5.05E-04	tpy
	Fluorene	1.28E-05	lb/MMBtu	1.61E-03	tpy
	Indeno(1,2,3-cd)pyrene	4.14E-07	lb/MMBtu	5.19E-05	tpy
91-20-3	Naphthalene	1.30E-04	lb/MMBtu	1.63E-02	tpy
	Phenanthrene	4.08E-05	lb/MMBtu	5.12E-03	tpy
	Pyrene	3.71E-06	lb/MMBtu	4.65E-04	tpy
		Total Potential HAP Emissions:		**0.2**	**tpy**

Notes:
[1] Total fuel use based on maximum full-time operation or permit-limited operation as noted below:

EU ID 14	Generator Engine		21.1	MMBtu/hr
			8,760	hrs
		Potential Heat Input:	185,018	MMBtu/yr
EU ID 22	Generator Engine		7.5	MMBtu/hr
			8,760	hrs
		Potential Heat Input:	65,784	MMBtu/yr
		Total Potential Heat Input:	**250,802**	**MMBtu/yr**
Engines heat rate:			7,000	Btu/hp-hr

[2] Reference: AP-42, Table 3.4-3 and Table 3.4-4

Table D2-16. Potential Annual Emissions (before controls/limitations) Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Insignificant Emission Units - Natural Gas Fired Heaters

73,812 MMBtu/yr [1]

CAS No.	Chemical Name	Source Category Emission Calculations: AP-42 Emission Factor [2]		Estimated Emissions [3]	
91-57-6	2-Methylnapthalene	2.40E-05	lb/MMscf	8.68E-07	tpy
56-49-5	3-Methylcholanthrene	1.80E-06	lb/MMscf	6.51E-08	tpy
	7,12-Dimethylbenz(a)anthracene	1.60E-05	lb/MMscf	5.79E-07	tpy
83-32-9	Acenaphthene	1.80E-06	lb/MMscf	6.51E-08	tpy
203-96-8	Acenaphthylene	1.80E-06	lb/MMscf	6.51E-08	tpy
120-12-7	Anthracene	2.40E-06	lb/MMscf	8.68E-08	tpy
56-55-3	Benz(a)anthracene	1.80E-06	lb/MMscf	6.51E-08	tpy
71-43-2	Benzene	2.10E-03	lb/MMscf	7.60E-05	tpy
50-32-8	Benzo(a)pyrene	1.20E-06	lb/MMscf	4.34E-08	tpy
205-99-2	Benzo(b)fluoranthene	1.80E-06	lb/MMscf	6.51E-08	tpy
191-24-2	Benzo(g,h,i)perylene	1.20E-06	lb/MMscf	4.34E-08	tpy
207-08-9	Benzo(k)fluoranthene	1.80E-06	lb/MMscf	6.51E-08	tpy
218-01-9	Chrysene	1.80E-06	lb/MMscf	6.51E-08	tpy
53-70-3	Dibenzo(a,h)anthracene	1.20E-06	lb/MMscf	4.34E-08	tpy
25321-22-6	Dichlorobenzene	1.20E-03	lb/MMscf	4.34E-05	tpy
206-44-0	Fluoranthene	3.00E-06	lb/MMscf	1.09E-07	tpy
86-73-7	Fluorene	2.80E-06	lb/MMscf	1.01E-07	tpy
50-00-0	Formaldehyde	7.50E-02	lb/MMscf	2.71E-03	tpy
110-54-3	Hexane	1.80E+00	lb/MMscf	6.51E-02	tpy
193-39-5	Indeno(1,2,3-cd)pyrene	1.80E-06	lb/MMscf	6.51E-08	tpy
91-20-3	Naphthalene	6.10E-04	lb/MMscf	2.21E-05	tpy
85-01-8	Phenanathrene	1.70E-05	lb/MMscf	6.15E-07	tpy
129-00-0	Pyrene	5.00E-06	lb/MMscf	1.81E-07	tpy
108-88-3	Toluene	3.40E-03	lb/MMscf	1.23E-04	tpy
7440-38-2	Arsenic	2.00E-04	lb/MMscf	7.24E-06	tpy
7440-41-7	Beryllium	1.20E-05	lb/MMscf	4.34E-07	tpy
7440-43-9	Cadmium	1.10E-03	lb/MMscf	3.98E-05	tpy
7440-47-3	Chromium	1.40E-03	lb/MMscf	5.07E-05	tpy
7440-48-4	Cobalt	8.40E-05	lb/MMscf	3.04E-06	tpy
7439-96-5	Manganese	3.80E-04	lb/MMscf	1.37E-05	tpy
7439-97-6	Mercury	2.60E-04	lb/MMscf	9.41E-06	tpy
7440-02-0	Nickel	2.10E-03	lb/MMscf	7.60E-05	tpy
7782-49-2	Selenium	2.40E-05	lb/MMscf	8.68E-07	tpy
	Total Potential HAP Emissions:			**0.07**	**tpy**

Notes:
[1] Total fuel use based on maximum full-time operation as noted below.

Insignificant EUs	Various	8.4	MMBtu/hr
		8,760	hr/yr
	Potential Heat Input:	73,812	MMBtu/yr
	Total Potential Heat Input:	**73,812**	**MMBtu/yr**

[2] Reference: AP-42, Tables 1.4-3 and 1.4-4.
[3] Natural Gas High Heat Value: AP-42 Table 1.4-2, 3.1-2a 1,020 Btu/scf

Table D2-17. Potential Annual Emissions (before controls/limitations) Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Insignificant Emission Units - Diesel Fired Heaters

Potential Total Heat Input for Insignificant Emissions Units: 32,412 MMBtu/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**AP-42 Emission Factor [2]**	**Estimated Emissions**
N/A	Arsenic Compounds	4.00E-06 lb/MMBtu	6.48E-05 tpy
71-43-2	Benzene	2.10E-04 lb/MMBtu	3.40E-03 tpy
N/A	Beryllium Compounds	3.00E-06 lb/MMBtu	4.86E-05 tpy
N/A	Cadmium Compounds	3.00E-06 lb/MMBtu	4.86E-05 tpy
N/A	Chromium Compounds	3.00E-06 lb/MMBtu	4.86E-05 tpy
100-41-4	Ethyl benzene	6.36E-05 lb/MMBtu	1.03E-03 tpy
50-00-0	Formaldehyde	3.30E-02 lb/MMBtu	5.35E-01 tpy
N/A	Lead Compounds	9.00E-06 lb/MMBtu	1.46E-04 tpy
N/A	Manganese Compounds	6.00E-06 lb/MMBtu	9.72E-05 tpy
N/A	Mercury Compounds	3.00E-06 lb/MMBtu	4.86E-05 tpy
N/A	Nickel Compounds	3.00E-06 lb/MMBtu	4.86E-05 tpy
N/A	Selenium Compounds	1.50E-05 lb/MMBtu	2.43E-04 tpy
108-88-3	Toluene	6.20E-03 lb/MMBtu	1.00E-01 tpy
71-55-6	1,1,1-Trichloroethane	2.36E-04 lb/MMBtu	3.82E-03 tpy
1330-20-7	Xylenes	1.09E-04 lb/MMBtu	1.77E-03 tpy
N/A	Polycyclic Organic Matter (POM)		2.34E-02 tpy
N/A	Polycyclic aromatic compounds(PAH)		2.34E-02 tpy
208-96-8	Acenaphthene	2.11E-05 lb/MMBtu	3.42E-04 tpy
83-32-9	Acenaphthylene	2.53E-04 lb/MMBtu	4.10E-03 tpy
120-12-7	Anthracene	1.22E-06 lb/MMBtu	1.98E-05 tpy
56-55-3	Benzo(a)anthracene	4.01E-06 lb/MMBtu	6.50E-05 tpy
205-99-2	Benzo(b,k)fluoranthene	1.48E-06 lb/MMBtu	2.40E-05 tpy
191-24-2	Benzo(g,h,i)perylene	2.26E-06 lb/MMBtu	3.66E-05 tpy
218-01-9	Chrysene	2.38E-06 lb/MMBtu	3.86E-05 tpy
53-70-3	Dibenz(a,h)anthracene	1.67E-06 lb/MMBtu	2.71E-05 tpy
206-44-0	Fluoranthene	4.84E-06 lb/MMBtu	7.84E-05 tpy
86-73-7	Fluorene	4.47E-06 lb/MMBtu	7.24E-05 tpy
193-39-5	Indeno(1,2,3-cd)pyrene	2.14E-06 lb/MMBtu	3.47E-05 tpy
91-20-3	Naphthalene	1.13E-03 lb/MMBtu	1.83E-02 tpy
85-01-8	Phenanthrene	1.05E-05 lb/MMBtu	1.70E-04 tpy
129-00-0	Pyrene	4.25E-06 lb/MMBtu	6.89E-05 tpy
		Total Potential HAP Emissions:	**6.69E-01 tpy**

Notes:

[1] Total fuel use based on maximum full-time operation as noted below.

Insignificant EUs	Various	3.7	MMBtu/hr
		8,760	hr/yr
	Potential Heat Input:	32,412	MMBtu/yr
	Total Potential Heat Input:	**32,412**	**MMBtu/yr**

[2] Reference: AP-42, Tables 1.3-9 and 1.3-10

Table D2-18a. Estimating Procedure for Determining HAP Content of Crude Storage Tank Vapors
Alyeska Pipeline Services Company - Pump Station 4

I. Sample Description/Comments

1. PS 1 discharge stream sample (sample date: 10/31/02)
2. Sample Date: 10/31/02
3. Sample ID: L1-021031-06
4. Core Laboratories data includes crude molecular weight and component wt% values.

II. Determine Component Mole Fractions in Liquid Crude

Methodology Assumptions/Comments:
1. The component mole fraction in crude is determined from component weight fraction and component molecular weight by assuming a mass of 1,000 lb of crude (see AP-42 Section 7.1.5).

2. The component molecular weight of Decanes+ is equal to the value required for the sum of all molecular weights to be equal to the Core Laboratories measured crude molecular weight of: 232 lb/lb-mole

Liquid Crude Analysis Data		Calculate Component Mole Fraction in Crude			
Component **i**	Component Weight Fraction in Crude (wt%/100) **Z_{Li}**	Component Molecular Weight **M_i**	Total Moles of Crude (sum ZL_i/M_i x 1000) **x_T**	Component Mole Fraction in Crude ($Z_{Li}/M_i/x_T$) **x_i**	Crude Molecular Weight (sum $Mi*x_i$) **M_T**
Methane	0	16	0	0	0
Ethane	0.0002	30	0.007	0.002	0.046
Propane	0.003	44	0.068	0.016	0.696
Isobutane	0.0044	58	0.076	0.018	1.021
N-Butane	0.0152	58	0.262	0.061	3.529
1,3 Butadiene	0	54	0	0	0
Isopentane	0.0088	72	0.122	0.028	2.043
N-Pentane	0.0127	72	0.176	0.041	2.948
N-Hexane	0.0104	86	0.121	0.028	2.414
Hexanes	0.0118	84	0.140	0.033	2.739
Benzene	0.0033	78	0.042	0.010	0.766
Heptanes	0.0392	97	0.404	0.094	9.100
2,2,4 Trimethylpentane	0	114	0	0	0
Toluene	0.0084	92	0.091	0.021	1.950
Octanes	0.0464	111	0.418	0.097	10.771
Ethyl Benzene	0.002	106	0.019	0.004	0.464
Xylenes	0.0095	106	0.090	0.021	2.205
Isopropylbenzene	0.0005	120	0.004	0.001	0.116
Nonanes	0.031	123	0.252	0.059	7.196
Naphthalene	0.0016	128	0.012	0.003	0.371
Decanes+	0.7916	395	2.004	0.465	183.76
SUM Z_{Li} / x_T / x_i / M_T	1.00		4.308	1.000	232

Notes:
1. Molecular weight values for component groups such as octanes are estimates from Core Laboratories.

Table D2-18b. Estimating Procedure for Determining HAP Content of Crude Storage Tank Vapors
Alyeska Pipeline Services Company - Pump Station 4

III. Determine Component Vapor Pressure at Given Crude Temperature

Methodology Assumptions/Comments:

1. Clausius-Clapeyron equation provides relationship between temperature and vapor pressure:

$$\log P_2/P_1 = H_v/2.303R^*(T_2-T_1/T_2T_1)$$

where R = Universal Gas Constant = 8.31448 J/g-mole·K = 3.58 Btu/lb-mole·K
Hv = Heat of Vaporization = see table below

2. Let P_1 be known component vapor pressure at known temperature T_1 = 100 F (311 K), and P_2 be unknown component vapor pressure at given crude temperature T_2 (shown below).

3. PS 3 crude (and vapor) constant temperature (P_2) of: 102 F 312 K
Based on average crude temperature at PS 3 during peak flow year 1995.

Component Physical Properties			Component Vapor Pressure at Crude Temperature			
Component **i**	Component Vapor Pressure at 100F (psia) **P_1**	Component Heat of Vaporization (Btu/lb-mole) **H_v**	Component Heat of Vaporization/ Gas Constant $H_v/2.303R$	Calculate $(T_2-T_1)/T_2T_1$	Calculate Inverse Log of $(H_v/2.303R)^*$ $(T_2-T_1)/T_2T_1$	Component Vapor Pressure at Crude Temperature (psia) **P_2**
Methane	5000	3520	426.9	0.00001	1.011	5056
Ethane	800	6349	770.1	0.00001	1.020	816
Propane	189	8071	978.9	0.00001	1.026	194
Isobutane	72.6	9136	1108.2	0.00001	1.030	74.7
N-Butane	51.7	9642	1169.5	0.00001	1.031	53.3
1,3 Butadiene	59.5	10025	1215.9	0.00001	1.033	61.4
Isopentane	20.4	10613	1287.3	0.00001	1.034	21.1
N-Pentane	15.6	11082	1344.2	0.00001	1.036	16.2
N-Hexane	4.96	12404	1504.5	0.00001	1.040	5.16
Hexanes	10	12500	1516.1	0.00001	1.041	10.41
Benzene	3.22	13215	1602.8	0.00001	1.043	3.36
Heptanes	3.5	13500	1637.4	0.00001	1.044	3.65
2,2,4 Trimethylpentane	1.70	14000	1698.1	0.00001	1.046	1.8
Toluene	1.03	14263	1730.0	0.00001	1.047	1.08
Octanes	1	14500	1758.7	0.00001	1.047	1.05
Ethyl Benzene	0.37	15288	1854.3	0.00001	1.050	0.39
Xylenes	0.33	16000	1940.6	0.00001	1.052	0.35
Isopropylbenzene	0.19	16136	1957.1	0.00001	1.053	0.20
Nonanes	0.40	16500	2001.3	0.00001	1.054	0.42
Naphthalene	0.13	16700	2025.5	0.00001	1.055	0.14
Decanes+	0.1	47282	5734.7	0.00001	1.163	0.12

Notes:
1. Heat of Vaporization and vapor pressure of pure components from GPSA Engineering Data Book, Volume II, Section 23.
2. Vapor pressure values for component groups such as octanes are estimates from Core Laboratories.
3. Heat of Vaporization for component groups are estimates based on values for individual components within the group.

Table D2-18c. Estimating Procedure for Determining HAP Content of Crude Storage Tank Vapors
Alyeska Pipeline Services Company - Pump Station 4

IV. Determine Component Partial Pressure and Mole Fraction in Crude Vapor

Methodology Assumptions/Comments:

1. Conservatively assume C_1-C_{10} hydrocarbons and HAPs are only species present in vapor phase due to dramatic dropoff in component vapor pressue as component molecular weight increases.

2. For speciation purposes, assume crude vapor pressure (P_{VA}) equal to sum of component partial pressures indicated below. This assumption ignores CO_2 present in crude and is conservative because it results in vapor mole fractions of listed components (including HAPs) being overstated.

3. Component partial pressure is equal to the component mole fraction in the liquid crude multiplied by the component vapor pressure at the given crude temperature:

$$P_i = P_2 * x_i$$

4. The component mole fraction in the crude vapor is then equal to the component partial pressure divided by the overall crude vapor pressure:

$$y_i = P_i / P_{VA}$$

	Calculation of Component Partial Pressure and Mole Fraction in Vapor			
Component **i**	Component Vapor Pressure at Crude Temperature (psia) **P_2**	Component Mole Fraction in Crude ($Z_{Li}/M_i/x_T$) **x_i**	Component Partial Pressure at Crude Temperature (P_2*x_i) **P_i**	Component Mole Fraction in Vapor (P_i/P_{VA}) **y_i**
Methane	5056	0	0	0
Ethane	816	0.0015	1.260	0.1126
Propane	194	0.0158	3.057	0.2729
Isobutane	74.7	0.0176	1.314	0.1173
N-Butane	53.3	0.0607	3.237	0.2890
1,3 Butadiene	61.4	0	0	0
Isopentane	21.1	0.0283	0.599	0.0535
N-Pentane	16.2	0.0409	0.660	0.0590
N-Hexane	5.16	0.0280	0.145	0.0129
Hexanes	10.41	0.0326	0.339	0.0303
Benzene	3.36	0.0098	0.033	0.0029
Heptanes	3.65	0.0938	0.343	0.0306
2,2,4 Trimethylpentane	1.78	0	0	0
Toluene	1.08	0.0212	0.023	0.0020
Octanes	1.05	0.0970	0.102	0.0091
Ethyl Benzene	0.39	0.0044	0.002	0.0002
Xylenes	0.35	0.0208	0.007	0.0006
Isopropylbenzene	0.20	0.0010	0.0002	0.00002
Nonanes	0.42	0.0585	0.025	0.0022
Naphthalene	0.14	0.0029	0.000	0.0000
Decanes+	0.12	0.4652	0.054	0.0048
P_{VA} / y_i SUM			11.2	1.00

Table D2-18d. Estimating Procedure for Determining HAP Content of Crude Storage Tank Vapors
Alyeska Pipeline Services Company - Pump Station 4

V. Determine Component Weight Fractions in Crude Vapor

1. Component weight fraction in the vapor is determined in two steps. First, the overall vapor molecular weight is determined by summing the product of the molecular weight and vapor mole fraction for each component:

$$M_V = \text{sum}\ (M_i * y_i)$$

2. Then, the component weight fraction is determined by dividing the product of the molecular weight and vapor mole fraction for each component by the overall vapor molecular weight:

$$Z_{Vi} = (M_i * y_i)/M_V$$

Component Physical Properties		Calculation of Component Weight Fraction in Vapor		
Component **i**	Component Molecular Weight **M_i**	Component Mole Fraction in Vapor (P_i/P_{VA}) **y_i**	Calculate Vapor Molecular Weight (sum M_i*y_i) **M_V**	Component Weight Fraction in Vapor (Mi*y_i/M_V) **Z_{Vi}**
Methane	16	0	0	0
Ethane	30	0.1126	3.38	0.0589
Propane	44	0.2729	12.04	0.2094
Isobutane	58	0.1173	6.82	0.1186
N-Butane	58	0.2890	16.80	0.2923
1,3 Butadiene	54	0	0	0
Isopentane	72	0.0535	3.86	0.0671
N-Pentane	72	0.0590	4.25	0.0740
N-Hexane	86	0.0129	1.11	0.0194
Hexanes	84	0.0303	2.55	0.0443
Benzene	78	0.0029	0.23	0.0040
Heptanes	97	0.0306	2.97	0.0517
2,2,4 Trimethylpentane	114	0	0	0
Toluene	92	0.0020	0.19	0.0033
Octanes	111	0.0091	1.01	0.0175
Ethyl Benzene	106	0.0002	0.02	0.0003
Xylenes	106	0.0006	0.07	0.0012
Isopropylbenzene	120	0.00002	0.002	0.00004
Nonanes	123	0.0022	0.27	0.0047
Naphthalene	128	0.0000	0.00	0.0001
Decanes+	395	0.0048	1.91	0.0332
y_i SUM / M_v / Z_{vi} SUM		1.00	57.5	1.00

Table D2-19. Potential Annual Emissions (before controls/limitations) Calculations - Greenhouse Gas (GHG) Summary
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel Type	Potential Greenhouse Gas Emissions (tpy)				
ID	Description	Rating/Capacity		CO_2	CH_4	N_2O	GHG Mass	GHG CO_2e [1]
Significant Emissions Units								
8	Heater	20.6 MMBtu/hr	Natural Gas	0	0	0	0	5
			Diesel	14,681	0.6	0.1	14,682	14,729
9	Heater	20.6 MMBtu/hr	Natural Gas	0	0	0	0	0
			Diesel	14,681	0.60	0.1	14,682	14,729
12	Cyclone Turbine	12.9 MW	Natural Gas	0	0	0	0	0
			Diesel	86,300	3.50	0.7	86,304	86,583
13	Cyclone Turbine	12.9 MW	Natural Gas	61,913	1.2	0.1	61,914	61,976
14	Generator Engine	2,250 kW	Diesel	15,052	0.6	0.1	15,053	15,102
15	Generator Engine	65 kW	Diesel	435	0.02	0.004	435	436
21	Breakout Tank 140	150,000 bbl	N/A	0	0	0	0	0
22	Generator Engine	800 kW	Diesel	5,352	0.22	0.04	5,352	5,370
Significant Emissions Units Emissions - Greenhouse Gases							**198,422**	**198,931**
Insignificant Emissions Unit								
N/A	Heater	0.763 MMBtu/hr	Natural Gas	390	0.007	7.4E-04	390	391
N/A	Heater	0.763 MMBtu/hr	Natural Gas	390	0.007	7.4E-04	390	391
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Diesel	356	0.01	0.003	356	358
N/A	Heater	0.600 MMBtu/hr	Diesel	428	0.02	0.003	428	429
N/A	Heater	0.600 MMBtu/hr	Diesel	428	0.02	0.003	428	429
N/A	Heater	0.800 MMBtu/hr	Diesel	570	0.02	0.005	570	572
N/A	Heater	0.800 MMBtu/hr	Diesel	570	0.02	0.005	570	572
N/A	Heater	0.400 MMBtu/hr	Diesel	285	0.01	0.002	285	286
Insignificant Emissions Unit Emissions - Greenhouse Gases							**6,945**	**6,958**
Total Emissions - Greenhouse Gases							**205,367**	**205,890**

Notes:

[1] GHG emissions are defined as CO_2e emissions.

Per 40 CFR 98. Table A-1. Please note CO_2e is the summation of CO_2 (1), CH_4 (85), and N_2O (265), applying the global warming potential for each pollutant.

Table D2-20. Potential Annual Emissions (before controls/limitations) Calculations - Carbon Dioxide (CO_2)
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel	Factor	CO_2 Emission	Potential	Potential
ID	**Description**	**Rating/Capacity**	**Type**	**Reference**	**Factor**	**Operation**	**CO_2 Emissions [1]**
Significant Emissions Units							
8	Heater	20.6 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	0 hours	0 tpy
			Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours [2]	14,681 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	0 hours	0 tpy
			Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours [2]	14,681 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	0 hours	0 tpy
			Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours [2]	86,300 tpy
13	Cyclone Turbine	12.9 MW	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	61,913 tpy
14	Generator Engine	2,250 kW	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours	15,052 tpy
15	Generator Engine	65 kW	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours	435 tpy
21	Breakout Tank 140	150,000 bbl	N/A	N/A	N/A	8,760 hours	0 tpy
22	Generator Engine	800 kW	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours	5,352 tpy
						Significant Emissions Units Emissions - CO_2	**198,414 tpy**
Insignificant Emissions Units							
N/A	Heater	0.763 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	390 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	390 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours	356 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours	428 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours	428 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours	570 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours	570 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours	285 tpy
						Insignificant Emissions Units Emissions - CO_2	**6,945 tpy**
						Total Emissions - CO_2	**205,359 tpy**

Notes:
[1] Parameters and conversions:
Average BSFC, Table 3.4-1, AP-42 — 7,000 Btu/hp-hr
[2] Assumed worst case emissions scenario with maximum operation on diesel for EU IDs 8,9, and 12.

Table D2-21. Potential Annual Emissions (before controls/limitations) Calculations - Methane (CH_4)
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel	Factor	CH_4 Emission	Potential	Potential
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	CH_4 Emissions [1]
Significant Emissions Units							
8	Heater	20.6 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	0 hours	0 tpy
			Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours [2]	0.6 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	0 hours	0 tpy
			Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours [2]	0.6 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	0 hours	0 tpy
			Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours [2]	3.5 tpy
13	Cyclone Turbine	12.9 MW	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	1.2 tpy
14	Generator Engine	2,250 kW	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours	0.6 tpy
15	Generator Engine	65 kW	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours	0.02 tpy
21	Breakout Tank 140	150,000 bbl	N/A	N/A	N/A	8,760 hours	0 tpy
22	Generator Engine	800 kW	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours	0.2 tpy
						Significant Emissions Units Emissions - CH_4	**6.7 tpy**
Insignificant Emissions Units							
N/A	Heater	0.763 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.007 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.003 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.003 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.003 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.003 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.003 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.003 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.003 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.003 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.005 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.005 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.005 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.005 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.005 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.005 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.005 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.005 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	0.005 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours	0.01 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours	0.02 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours	0.02 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours	0.02 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours	0.02 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours	0.01 tpy
						Insignificant Emissions Units Emissions - CH_4	**0.2 tpy**
						Total Emissions - CH_4	**6.9 tpy**

Notes:
[1] Parameters and conversions:
Average BSFC, Table 3.4-1, AP-42 7,000 Btu/hp-hr
[2] Assumed worst case emissions scenario with maximum operation on diesel for EU IDs 8,9, and 12

Table D2-22. Potential Annual Emissions (before controls/limitations) Calculations - Nitrous Oxide (N_2O)
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel	Factor	N_2O Emission	Potential	Potential
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	N_2O Emissions [1]
Significant Emissions Units							
8	Heater	20.6 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	0 tpy
			Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours [2]	0.1 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	0 hours	0 tpy
			Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours [2]	0.1 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	0 hours	0 tpy
			Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours [2]	0.7 tpy
13	Cyclone Turbine	12.9 MW	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	0.1 tpy
14	Generator Engine	2,250 kW	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours	0.1 tpy
15	Generator Engine	65 kW	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours	0.004 tpy
21	Breakout Tank 140	150,000 bbl	N/A	N/A	N/A	8,760 hours	0 tpy
22	Generator Engine	800 kW	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours	0.04 tpy
						Significant Emissions Units Emissions - N_2O	**1.2 tpy**
Insignificant Emissions Units							
N/A	Heater	0.763 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	7.35E-04 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	7.35E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.89E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.89E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.89E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.89E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.89E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.89E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.89E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.89E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.82E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.82E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.82E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.82E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.82E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.82E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.82E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.82E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.82E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours	0.003 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours	0.003 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours	0.003 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours	0.005 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours	0.005 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours	0.002 tpy
						Insignificant Emissions Units Emissions - N_2O	**0.03 tpy**
						Total Emissions - N_2O	**1.3 tpy**

Notes:
[1] Parameters and conversions:
Average BSFC, Table 3.4-1, AP-42 — 7,000 Btu/hp-hr
[2] Assumed worst case emissions scenario with maximum operation on diesel for EU IDs 8,9, and 12.

D.3 Form D3: Expected Actual Annual Emissions

Table D3-1. Actual Annual Emissions Summary
Alyeska Pipeline Services Company - Pump Station 4

Potential to Emit	Regulated Air Pollutant Emissions (tons per year) [1,2]							
	NO_X	CO	PM_{10}	$PM_{2.5}$ [4]	VOC	SO_2	HAP	GHG [3]
Significant	53.3	171.0	3.2	3.2	21.2	3.7	1.4	59,982
Insignificant	6.0	3.6	0.7	0.7	0.2	4.2	0.7	6,958

Notes:
[1] Emissions are based on actual operation from calendar year 2024.
[2] See individual emissions unit category HAP emissions calculations for details on methodology and assumptions (electronic copy).
[3] GHG emissions are defined as CO_2e emissions. CO_2e is the summation of CO_2, CH_4, and N_2O, applying the global warming potential for each pollutant.
[4] $PM_{2.5}$ emissions are assumed to be equivalent to PM_{10} emissions.

Table D3-2a. Significant Emissions Unit Inventory
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit				Fuel	CY 2024 Actual
ID	Name	Description	Rating	Type	Operation
8	Heater	Eclipse Therminol	20.6 MMBtu/hr	Natural Gas	96 MMscf/yr
				Diesel	0 gal/yr
9	Heater	Eclipse Therminol	20.6 MMBtu/hr	Natural Gas	0 MMscf/yr
				Diesel	0 gal/yr
12	Cyclone Turbine	Siemens / SGT-400	12.9 MW	Natural Gas	489 MMscf/yr
				Diesel	0 gal/yr
13	Cyclone Turbine	Siemens / SGT-400	12.9 MW	Natural Gas	421 MMscf/yr
14	Generator Engine	Caterpillar / 3516B	2250.0 kW	Diesel	0 hrs/yr
15	Generator Engine	John Deere	65.0 kW	Diesel	8 hrs/yr
21	Breakout Tank 140	Crude Oil Storage Tank	150,000 bbl	N/A	8,760 hrs/yr
22	Generator Engine	Detroit Diesel / 2000G45TB	800 kW	Diesel	9 hrs/yr

Table D3-2b. Insignificant Emissions Unit Inventory
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit(s)			Fuel / Material Type	Maximum Operation	Rating	Basis for Insignificance
ID	Description	Make/Model				
N/A	Heater	Burnham	Natural Gas	8,760 hours	0.763 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Burnham	Natural Gas	8,760 hours	0.763 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Hastings	Natural Gas	8,760 hours	0.300 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Modine	Natural Gas	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(5)
N/A	Heater	Ground	Diesel	8,760 hours	0.500 MMBtu/hr	18 AAC 50.326(g)(7)
N/A	Heater	Tioga	Diesel	8,760 hours	0.600 MMBtu/hr	18 AAC 50.326(g)(7)
N/A	Heater	Tioga	Diesel	8,760 hours	0.600 MMBtu/hr	18 AAC 50.326(g)(7)
N/A	Heater	Chinook	Diesel	8,760 hours	0.800 MMBtu/hr	18 AAC 50.326(g)(7)
N/A	Heater	Chinook	Diesel	8,760 hours	0.800 MMBtu/hr	18 AAC 50.326(g)(7)
N/A	Heater	Aerotec	Diesel	8,760 hours	0.400 MMBtu/hr	18 AAC 50.326(g)(7)

Table D3-3. Actual Annual Emissions Calculations - Oxides of Nitrogen (NO_X)
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel	Factor	NO_X Emission	CY 2024 Actual	Actual
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	NO_X Emissions [1]
Significant Emissions Units							
8	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	96 MMscf/yr	4.82 tpy
			Diesel	AP-42 Table 1.3-1	20 lb/Mgal	0 gal/yr	0 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	0 MMscf/yr	0 tpy
			Diesel	AP-42 Table 1.3-1	20 lb/Mgal	0 gal/yr	0 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	Manufacturer's Data	Load based	489 MMscf/yr	26.5 tpy
			Diesel			0 gal/yr	
13	Cyclone Turbine	12.9 MW	Natural Gas	Manufacturer's Data	Load based	421 MMscf/yr	21.9 tpy
14	Generator Engine	2,250 kW	Diesel	Manufacturer's Data	71 lb/hr	0 hrs/yr	0 tpy
15	Generator Engine	65 kW	Diesel	Tier 2 Standard [2]	7.5 g/kW-hr	8 hrs/yr	0.004 tpy
21	Breakout Tank 140	150,000 bbl	N/A	N/A	N/A	8,760 hrs/yr	0 tpy
22	Generator Engine	800 kW	Diesel	Manufacturer's Data	11.0 lb/hr	9 hrs/yr	0.05 tpy
Significant Emissions Units Emissions - NO_X							**53.3 tpy**
Insignificant Emissions Units							
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.3 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.3 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	100 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	AP-42 Table 1.3-1	20 lb/Mgal	8,760 hours	0.3 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-1	20 lb/Mgal	8,760 hours	0.4 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-1	20 lb/Mgal	8,760 hours	0.4 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-1	20 lb/Mgal	8,760 hours	0.5 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-1	20 lb/Mgal	8,760 hours	0.5 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	AP-42 Table 1.3-1	20 lb/Mgal	8,760 hours	0.3 tpy
Insignificant Emissions Units Emissions - NO_X							**6.0 tpy**
Total Emissions - NO_X							**59.2 tpy**

Notes:
[1] Parameters and Conversions:
- Natural Gas High Heat Value: AP-42 Table 1.4-1 — 1,020 Btu/scf
- Diesel High Heat Value: AP-42 Table 1.3-1 — 139 MMBtu/10^3 gal
- Average BSFC, Table 3.4-1, AP-42 — 7,000 Btu/hp-hr

[2] Appendix I to 40 CFR Part 1039(b)

Table D3-4. Actual Annual Emissions Calculations - Carbon Monoxide (CO)
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel	Factor	CO Emission	CY 2024 Actual	Actual
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	CO Emissions [1]
Significant Emissions Units							
8	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	96 MMscf/yr	4.05 tpy
			Diesel	AP-42 Table 1.3-1	5 lb/Mgal	0 gal/yr	0 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	0 MMscf/yr	0 tpy
			Diesel	AP-42 Table 1.3-1	5 lb/Mgal	0 gal/yr	0 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	Manufacturer's Data	Load based	489 MMscf/yr	124.2 tpy
			Diesel			0 gal/yr	
13	Cyclone Turbine	12.9 MW	Natural Gas	Manufacturer's Data	Load based	421 MMscf/yr	42.7 tpy
14	Generator Engine	2,250 kW	Diesel	Manufacturer's Data	2 lb/hr	0 hrs/yr	0 tpy
15	Generator Engine	65 kW	Diesel	Tier 2 Standard [2]	5.0 g/kW-hr	8 hrs/yr	0 tpy
21	Breakout Tank 140	150,000 bbl	N/A	N/A	N/A	8,760 hrs/yr	0 tpy
22	Generator Engine	800 kW	Diesel	Manufacturer's Data	1.1 lb/hr	9 hrs/yr	0.005 tpy
						Significant Emissions Units Emissions - CO	**171.0 tpy**
Insignificant Emissions Units							
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.3 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.3 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.1 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	84 lb/MMscf	8,760 hours	0.2 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	AP-42 Table 1.3-1	5 lb/Mgal	8,760 hours	0.1 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-1	5 lb/Mgal	8,760 hours	0.1 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-1	5 lb/Mgal	8,760 hours	0.1 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-1	5 lb/Mgal	8,760 hours	0.1 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-1	5 lb/Mgal	8,760 hours	0.1 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	AP-42 Table 1.3-1	5 lb/Mgal	8,760 hours	0.06 tpy
						Insignificant Emissions Units Emissions - CO	**3.6 tpy**
						Total Emissions - CO	**174.6 tpy**

Notes:
[1] Parameters and Conversions:

Natural Gas High Heat Value: AP-42 Table 1.4-1, 3.1-1	1,020 Btu/scf
Diesel High Heat Value: AP-42 Table 1.3-1	139 MMBtu/10^3 gal
Average BSFC, Table 3.4-1, AP-42	7,000 Btu/hp-hr

[2] Appendix I to 40 CFR Part 1039(b)

Table D3-5. Actual Annual Emissions Calculations - Particulate Matter Less Than 10 Microns (PM_{10})
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit ID	Emissions Unit Description	Emissions Unit Rating/Capacity	Fuel Type	Factor Reference	PM_{10} Emission Factor	CY 2024 Actual Operation	Actual PM_{10} Emissions [1]
Significant Emissions Units							
8	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	96 MMscf/yr	0.09 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.3 tpy
			Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	0 gal/yr	0 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	0 MMscf/yr	0 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0 tpy
			Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	0 gal/yr	0 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	Manufacturer's Data	Load based	489 MMscf/yr	1.5 tpy
			Diesel			0 gal/yr	
13	Cyclone Turbine	12.9 MW	Natural Gas	Manufacturer's Data	Load based	421 MMscf/yr	1.3 tpy
14	Generator Engine	2,250 kW	Diesel	Manufacturer's Data	0.6 lb/hr	0 hrs/yr	0 tpy
15	Generator Engine	65 kW	Diesel	AP-42 Table 3.3-1	3.1E-01 lb/MMBtu	8 hrs/yr	7.6E-04 tpy
21	Breakout Tank 140	150,000 bbl	N/A	N/A	N/A	8,760 hrs/yr	0 tpy
22	Generator Engine	800 kW	Diesel	Manufacturer's Data	0.09 lb/hr	9 hrs/yr	4.1E-04 tpy
						Significant Emissions Units Emissions - PM_{10}	**3.2 tpy**
Insignificant Emissions Units							
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.006 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.02 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.006 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.02 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.002 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.007 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.4-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.3-1 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.3-2 (condensable)	5.7 lb/MMscf		0.012 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.3-1 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.3-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.3-1 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.3-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.3-1 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.3-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.3-1 (filterable)	1.9 lb/MMscf	8,760 hours	0.004 tpy
				AP-42 Table 1.3-2 (condensable)	5.7 lb/MMscf		0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	8,760 hours	0.03 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0.02 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	8,760 hours	0.04 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0.02 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	8,760 hours	0.04 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0.02 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	8,760 hours	0.05 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0.03 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	8,760 hours	0.05 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0.03 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	AP-42 Table 1.3-1 (filterable)	2.0 lb/Mgal	8,760 hours	0.03 tpy
				AP-42 Table 1.3-2 (condensable)	1.3 lb/Mgal		0.02 tpy
						Insignificant Emissions Units Emissions - PM_{10}	**0.7 tpy**
						Total PM_{10} Emissions	**3.8 tpy**

Notes:
[1] Parameters and Conversions:

Natural Gas High Heat Value: AP-42 Table 1.4-1, 3.	1,020	Btu/scf
Diesel High Heat Value: AP-42 Table 1.3-1	139	MMBtu/10^3 gal
Average BSFC, Table 3.4-1, AP-42	7,000	Btu/hp-hr

Table D3-6a. Actual Annual Emissions Calculations - Volatile Organic Compunds (VOC)
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel	Factor	VOC Emission	CY 2024 Actual	Actual
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	VOC Emissions [1]
Significant Emissions Units							
8	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	96 MMscf/yr	0.3 tpy
			Diesel	AP-42 Table 1.3-3	0.252 lb/Mgal	0 gal/yr	0 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	AP-42 Table 1.4-2	5.5 lb/MMscf	0 MMscf/yr	0 tpy
			Diesel	AP-42 Table 1.3-3	0.252 lb/Mgal	0 gal/yr	0 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	Manufacturer's Data	Load based	489 MMscf/yr	0.5 tpy
			Diesel			0 gal/yr	
13	Cyclone Turbine	12.9 MW	Natural Gas	Manufacturer's Data	Load based	421 MMscf/yr	0.4 tpy
14	Generator Engine	2,250 kW	Diesel	Manufacturer's Data	1 lb/hr	0 hrs/yr	0 tpy
15	Generator Engine	65 kW	Diesel	AP-42 Table 3.3-1	2.47E-03 lb/hp-hr	8 hrs/yr	8.6E-04 tpy
21	Breakout Tank 140	150,000 bbl	N/A	N/A	N/A	8,760 hrs/yr	20.1 tpy
22	Generator Engine	800 kW	Diesel	Manufacturer's Data	0.3 lb/hr	9 hrs/yr	0.001 tpy
						Significant Emissions Units Emissions - VOC	**21.2 tpy**
Insignificant Emissions Units							
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.02 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.02 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.007 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.012 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	AP-42 Table 1.4-1	5.5 lb/MMscf	8,760 hours	0.01 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	AP-42 Table 1.3-1	0.252 lb/Mgal	8,760 hours	0.004 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-1	0.252 lb/Mgal	8,760 hours	0.005 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	AP-42 Table 1.3-1	0.252 lb/Mgal	8,760 hours	0.005 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-1	0.252 lb/Mgal	8,760 hours	0.006 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	AP-42 Table 1.3-1	0.252 lb/Mgal	8,760 hours	0.006 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	AP-42 Table 1.3-1	0.252 lb/Mgal	8,760 hours	0.003 tpy
						Insignificant Emissions Units Emissions - VOC	**0.2 tpy**
						Total Emissions - VOC	**21.5 tpy**

Notes:
[1] Parameters and Conversions:

Natural Gas High Heat Value: AP-42 Table 1.4-2, 3.1-2a	1,020	Btu/scf
Diesel High Heat Value: AP-42 Table 1.3-1	139	MMBtu/10^3 gal
Average BSFC, Table 3.4-1, AP-42	7,000	Btu/hp-hr

Table D3-6b. Actual Annual Emissions Calculations - Tank Emissions
Alyeska Pipeline Services Company - Pump Station 4

Tank Description	Breakout Tank 140
Orientation	Vertical
Contents	Crude Oil
Capacity (gallons)	2,310,000
Diameter, D (ft)	116
Radium, R_S (ft)	58
Shell Height, H_S (ft)	32
Average Liquid Height (H_L)	28.0
Maximum Liquid Height (H_{LX})	31
Crude Throughput (bbl/yr)	55,000
Color	White
Paint Condition	Good
Roof Type	Cone
Slope, S_R (ft/ft)	0.125
Standing Loss (L_S) Calculations	
Vapor Space Expansion Factor, K_E	0.016
Vapor Space Outage, H_{VO} (ft)	6.42
Average Daily Ambient Temperature, T_{AA} (°R)	471.70
Liquid Bulk Temperature, T_B (°R)	471.71
Average Daily Liquid Surface Temperature, T_{LA} (°R)	471.73
Average Vapor Temperature, T_V (°R)	471.75
Vented Vapor Density, K_S	0.1665
Stock Vapor Density, W_V (lb/ft^3)	1.45E-01
Standing Loss, L_S (lb/yr)	**9763.48**
Working Loss (L_W) Calculations	
Tank Maximum Liquid Volume, V_{LX} (ft^3)	327,618
Number of Turnovers per Year, N	1.00
Turnover Factor, K_N	1.0
Working Loss, L_W (lb/yr)	**30,360**
Total VOCs (tpy)	**20.1**

Meteorological Inputs (Prudhoe Bay, AK):

T_{AX} =	18.1 F	478.1 R
T_{AN} =	5.3 F	465.3 R
a =	0.25	White, Average
I =	18.5	Btu/ft^2-d

Constants:

K_P (crude)=	0.75	
M_V (crude)=	50	lb/lb-mol
P_{va} (crude)=	14.72	psi

Table D3-7. Actual Annual Emissions Calculations - Sulfur Dioxide (SO_2)
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel	Factor	Maximum Fuel	SO_2 Emission	CY 2024 Actual	Actual
ID	Description	Rating/Capacity	Type	Reference	Sulfur Content [1,2]	Factor	Operation	SO_2 Emissions [3]
Significant Emissions Units								
8	Heater	20.6 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	96 MMscf/yr	1.2 tpy
			Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	0 gal/yr	0 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	0 MMscf/yr	0 tpy
			Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	0 gal/yr	0 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	Mass Balance	150 ppmv H_2S	Load based	489 MMscf/yr	1.5 tpy
			Diesel		0.2 wt.% S		0 gal/yr	
13	Cyclone Turbine	12.9 MW	Natural Gas	Mass Balance	150 ppmv H_2S	Load based	421 MMscf/yr	1.0 tpy
14	Generator Engine	2,250 kW	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	0 hrs/yr	0 tpy
15	Generator Engine	65 kW	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8 hrs/yr	5.0E-04 tpy
21	Breakout Tank 140	150,000 bbl	N/A	N/A	N/A	N/A	8,760 hrs/yr	0 tpy
22	Generator Engine	800 kW	Diesel	Manufacturer's Data	0.0015 wt.% S	2.13E-04 lb/gal	9 hrs/yr	5.2E-05 tpy
							Significant Emissions Units Emissions - SO_2	**3.7 tpy**
Insignificant Emissions Units								
N/A	Heater	0.763 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.08 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.08 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.03 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	Mass Balance	150 ppmv H_2S	25.3 lb/MMscf	8,760 hours	0.05 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8,760 hours	0.45 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8,760 hours	0.5 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8,760 hours	0.5 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8,760 hours	0.7 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8,760 hours	0.7 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	Mass Balance	0.2 wt.% S	2.84E-02 lb/gal	8,760 hours	0.4 tpy
							Insignificant Emissions Units Emissions - SO_2	**4.2 tpy**
							Total Emissions - SO_2	**7.9 tpy**

Notes:
[1] Per AQ0074TVP04 Condition 19.1 - Limit H_2S concentration of fuel gas to no greater than 150 ppmv
[2] Per AQ0074TVP04 Condition 19.2 - Limit fuel sulfur concentration of diesel fuel to no greater than 0.20 percent by weight
[3] Parameters and conversions:

Density of diesel fuel.	7.10	lb/gal
Natural Gas High Heat Value: AP-42 Table 1.4-2, 3.1-2a	1,020	Btu/scf
Diesel average heat value: Table 3.1-2a, AP-42.	139	MMBtu/10^3 gallons
Average BSFC, Table 3.4-1, AP-42	7,000	Btu/hp-hr

Table D3-8. Actual Annual Emissions Calculations - Hazardous Air Pollutants (HAP) Emissions Summary
Alyeska Pipeline Services Company - Pump Station 4

Hazardous Air Pollutant	Natural Gas Turbines	Natural Gas Heaters	Liquid Fugitives	Gas Fugitives	Diesel Engines <600 hp	Diesel Engines >600 hp	Insignificant Units NG [2]	Insignificant Units Diesel [2]	Total HAP Emissions
Acetaldehyde	1.86E-02	----	----	----	1.87E-06	8.52E-07	----	----	1.86E-02
Acrolein	2.97E-03	----	----	----	2.26E-07	2.66E-07	----	----	2.97E-03
Benzene	5.57E-03	1.01E-04	1.49E-01	1.72E-02	2.28E-06	2.62E-05	7.60E-05	3.40E-03	1.75E-01
1,3 Butadiene	2.00E-04	----	0.00E+00	0.00E+00	----	----	----	----	2.00E-04
Dichlorobenzene	----	5.78E-05	----	----	----	----	4.34E-05	----	1.01E-04
Ethyl benzene	1.49E-02	----	9.00E-02	0.00E+00	----	----	----	1.03E-03	1.06E-01
Formaldehyde	3.30E-01	3.62E-03	----	----	2.88E-06	2.67E-06	2.71E-03	5.35E-01	8.71E-01
Hexane	----	8.68E-02	----	----	----	----	6.51E-02	----	1.52E-01
Polycyclic aromatic compounds(PAH)	1.02E-03	3.27E-05	7.20E-02	----	4.10E-07	7.15E-06	2.44E-05	2.34E-02	9.65E-02
Polycyclic Organic Matter (POM)	----	3.27E-05	7.20E-02	----	4.10E-07	7.15E-06	2.44E-05	2.34E-02	9.55E-02
Acenaphthene	----	8.68E-08	----	----	3.47E-09	1.58E-07	6.51E-08	3.42E-04	3.42E-04
Acenaphthylene	----	8.68E-08	----	----	1.23E-08	3.12E-07	6.51E-08	4.10E-03	4.10E-03
Anthracene	----	1.16E-07	----	----	4.56E-09	4.16E-08	8.68E-08	1.98E-05	2.00E-05
Benzo(a)anthracene	----	----	----	----	4.10E-09	2.10E-08	----	6.50E-05	6.50E-05
Benzo(a)pyrene	----	5.78E-08	----	----	4.59E-10	8.68E-09	4.34E-08	----	1.10E-07
Benzo(b)fluoranthene	----	8.68E-08	----	----	2.42E-10	3.75E-08	6.51E-08	----	1.90E-07
Benzo(g,h,i)perylene	----	5.78E-08	----	----	----	----	4.34E-08	----	1.01E-07
Benzo(g,h,l)perylene	----	----	----	----	1.19E-09	1.88E-08	----	----	2.00E-08
Benzo(k)fluoranthene	----	8.68E-08	----	----	3.78E-10	7.37E-09	6.51E-08	----	1.60E-07
Chrysene	----	8.68E-08	----	----	8.62E-10	5.17E-08	6.51E-08	----	2.04E-07
Dibenz(a,h)anthracene	----	----	----	----	1.42E-09	1.17E-08	----	----	1.31E-08
7,12-Dimethylbenz(a)anthracene	----	7.71E-07	----	----	----	----	5.79E-07	----	1.35E-06
Fluoranthene	----	1.45E-07	----	----	1.86E-08	1.36E-07	1.09E-07	----	4.08E-07
Fluorene	----	1.35E-07	----	----	7.13E-08	4.33E-07	1.01E-07	----	7.40E-07
Indeno(1,2,3-cd)pyrene	----	8.68E-08	----	----	9.15E-10	1.40E-08	6.51E-08	----	1.67E-07
2-Methylnapthalene	----	1.16E-06	----	----	----	----	8.68E-07	----	2.03E-06
3-Methylcholanthrene	----	8.68E-08	----	----	----	----	6.51E-08	----	1.52E-07
Naphthalene	----	2.94E-05	7.20E-02	----	2.07E-07	4.39E-06	2.21E-05	----	7.21E-02
Phenanthrene	----	----	----	----	7.18E-08	1.38E-06	----	----	1.45E-06
Pyrene	----	2.41E-07	----	----	1.17E-08	1.25E-07	----	----	3.78E-07
Propylene Oxide	1.35E-02	----	----	----	----	----	----	----	1.35E-02
Toluene	6.03E-02	1.64E-04	3.78E-01	1.01E-01	9.98E-07	9.50E-06	----	1.00E-01	6.40E-01
Xylenes (isomers and mixture)	2.97E-02	----	----	----	6.96E-07	6.52E-06	----	----	2.97E-02
Arsenic	----	9.64E-06	----	----	----	----	----	----	9.64E-06
Beryllium	----	5.78E-07	----	----	----	----	----	----	5.78E-07
Cadmium	----	5.30E-05	----	----	----	----	----	----	5.30E-05
Chromium	----	6.75E-05	----	----	----	----	----	----	6.75E-05
Cobalt	----	4.05E-06	----	----	----	----	----	----	4.05E-06
Lead	----	----	----	----	----	----	----	----	0
Manganese	----	1.83E-05	----	----	----	----	----	----	1.83E-05
Mercury	----	1.25E-05	----	----	----	----	----	----	1.25E-05
Nickel	----	1.01E-04	----	----	----	----	----	----	1.01E-04
Selenium	----	1.16E-06	----	----	----	----	----	----	1.16E-06
Total HAPs - Maximum Individual HAP	**3.30E-01**	**8.68E-02**	**3.78E-01**	**1.01E-01**	**2.88E-06**	**2.62E-05**	**6.51E-02**	**5.35E-01**	**8.71E-01**
Total VOC HAP Emissions	**4.76E-01**	**9.07E-02**	**7.06E-01**	**1.18E-01**	**4.65E-05**	**6.80E-02**	**6.31E-01**	**2.08E+00**	**2.20E+00**
Total HAPs Emissions	**4.76E-01**	**9.10E-02**	**6.89E-01**	**1.18E-01**	**9.36E-06**	**5.32E-05**	**6.80E-02**	**6.63E-01**	**2.20E+00**

Notes:

[1] HAP emissions from the fuel storage tanks are considered negligible.
[2] The HAP emissions from insignificant natural gas heaters are included under Table D3-17 IEU NG Heaters and D3-18 IEU Diesel Heaters.

Table D3-9. Actual Annual Emissions Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Natural Gas Fired Turbines

928,200 MMBtu/yr [1]

CAS No.	Chemical Name	Source Category Emission Calculations AP-42 Emission Factor [2]		Actual Emissions	
	1,3 Butadiene	4.30E-07	lb/MMBtu	2.00E-04	tpy
	Acetaldehyde	4.00E-05	lb/MMBtu	1.86E-02	tpy
	Acrolein	6.40E-06	lb/MMBtu	2.97E-03	tpy
71-43-2	Benzene	1.20E-05	lb/MMBtu	5.57E-03	tpy
100-41-4	Ethyl benzene	3.20E-05	lb/MMBtu	1.49E-02	tpy
50-00-0	Formaldehyde	7.10E-04	lb/MMBtu	3.30E-01	tpy
	Napthalene	1.30E-06	lb/MMBtu	6.03E-04	tpy
	Polycyclic aromatic compounds(PAH)	2.20E-06	lb/MMBtu	1.02E-03	tpy
	Propylene Oxide	2.90E-05	lb/MMBtu	1.35E-02	tpy
108-88-3	Toluene	1.30E-04	lb/MMBtu	6.03E-02	tpy
1330-20-7	Xylenes (isomers and mixture)	6.40E-05	lb/MMBtu	2.97E-02	tpy
				4.77E-01	**tpy**

Notes:
[1] Total fuel use based on maximum full-time operation as noted below.

EU ID 12	Cyclone Turbine	121.1	MMBtu/hr
		489	MMscf/yr
	Potential Heat Input:	498,780	MMBtu/yr
EU ID 13	Cyclone Turbine	121.1	MMBtu/hr
		421	MMscf/yr
	Potential Heat Input:	429,420	MMBtu/yr
	Total Actual Heat Input:	**928,200**	**MMBtu/yr**

Average BSFC, Table 3.4-1, AP-42	7,000	Btu/hp-hr
Natural Gas High Heat Value: AP-42 Table 1.4-2, 3.1-2a	1,020	Btu/scf

[2] Reference: AP-42, Tables 3.1-3

Table D3-10. Actual Annual Emissions Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Natural Gas Fired Heaters

98,328 MMBtu/yr [1]

CAS No.	Chemical Name	Source Category Emission Calculations: AP-42 Emission Factor [2]		Estimated Emissions [3]	
91-57-6	2-Methylnapthalene	2.40E-05	lb/MMscf	1.16E-06	tpy
56-49-5	3-Methylcholanthrene	1.80E-06	lb/MMscf	8.68E-08	tpy
	7,12-Dimethylbenz(a)anthracene	1.60E-05	lb/MMscf	7.71E-07	tpy
83-32-9	Acenaphthene	1.80E-06	lb/MMscf	8.68E-08	tpy
203-96-8	Acenaphthylene	1.80E-06	lb/MMscf	8.68E-08	tpy
120-12-7	Anthracene	2.40E-06	lb/MMscf	1.16E-07	tpy
56-55-3	Benz(a)anthracene	1.80E-06	lb/MMscf	8.68E-08	tpy
71-43-2	Benzene	2.10E-03	lb/MMscf	1.01E-04	tpy
50-32-8	Benzo(a)pyrene	1.20E-06	lb/MMscf	5.78E-08	tpy
205-99-2	Benzo(b)fluoranthene	1.80E-06	lb/MMscf	8.68E-08	tpy
191-24-2	Benzo(g,h,i)perylene	1.20E-06	lb/MMscf	5.78E-08	tpy
207-08-9	Benzo(k)fluoranthene	1.80E-06	lb/MMscf	8.68E-08	tpy
218-01-9	Chrysene	1.80E-06	lb/MMscf	8.68E-08	tpy
53-70-3	Dibenzo(a,h)anthracene	1.20E-06	lb/MMscf	5.78E-08	tpy
25321-22-6	Dichlorobenzene	1.20E-03	lb/MMscf	5.78E-05	tpy
206-44-0	Fluoranthene	3.00E-06	lb/MMscf	1.45E-07	tpy
86-73-7	Fluorene	2.80E-06	lb/MMscf	1.35E-07	tpy
50-00-0	Formaldehyde	7.50E-02	lb/MMscf	3.62E-03	tpy
110-54-3	Hexane	1.80E+00	lb/MMscf	8.68E-02	tpy
193-39-5	Indeno(1,2,3-cd)pyrene	1.80E-06	lb/MMscf	8.68E-08	tpy
91-20-3	Naphthalene	6.10E-04	lb/MMscf	2.94E-05	tpy
85-01-8	Phenanathrene	1.70E-05	lb/MMscf	8.19E-07	tpy
74-98-6	Propane	1.60E+00	lb/MMscf	7.71E-02	tpy
129-00-0	Pyrene	5.00E-06	lb/MMscf	2.41E-07	tpy
108-88-3	Toluene	3.40E-03	lb/MMscf	1.64E-04	tpy
7440-38-2	Arsenic	2.00E-04	lb/MMscf	9.64E-06	tpy
7440-41-7	Beryllium	1.20E-05	lb/MMscf	5.78E-07	tpy
7440-43-9	Cadmium	1.10E-03	lb/MMscf	5.30E-05	tpy
7440-47-3	Chromium	1.40E-03	lb/MMscf	6.75E-05	tpy
7440-48-4	Cobalt	8.40E-05	lb/MMscf	4.05E-06	tpy
7439-96-5	Manganese	3.80E-04	lb/MMscf	1.83E-05	tpy
7439-97-6	Mercury	2.60E-04	lb/MMscf	1.25E-05	tpy
7440-02-0	Nickel	2.10E-03	lb/MMscf	1.01E-04	tpy
7782-49-2	Selenium	2.40E-05	lb/MMscf	1.16E-06	tpy
	Total Actual HAP Emissions:			**0.2**	**tpy**

Notes:
[1] Assumed worst case emissions scenario with maximum operation on natural gas for EU IDs 16, 17, 18, and 19.

EU ID 8	Heater	20.6	MMBtu/hr
		96	MMscf/yr
	Potential Heat Input:	98,328	MMBtu/yr
EU ID 9	Heater	20.6	MMBtu/hr
		0	MMscf/yr
	Potential Heat Input:	0	MMBtu/yr
	Total Potential Heat Input:	**98,328**	**MMBtu/yr**

[2] Reference: AP-42, Tables 1.4-3 and 1.4-4.
[3] Natural Gas High Heat Value: AP-42 Table 1.4-2 1,020 Btu/scf

Table D3-11. Actual Annual Emissions Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Piping Fugitives - Light Liquid Service

1. Assume that the TOC emissions (losses) are determined from emission factors in Protocol for Equipment Leak Estimates, EPA-453-95-017, November 1995.

2. Based on this protocol, and a TAPs facilities fugitive emissions study conducted by Alyeska in 1998, the potential TOC emissions for PS 4 are estimated to be:
   45 tpy (Light Liquid Service)

3. Conservatively assuming that the light liquid piping leaks are all associated with crude, the individual component emission rates (losses) are then determined using the crude liquid phase weight fractions as determined by Core Laboratories.

Calculation of Component Emission Rates (Losses) - Light Liquids				
Component	Component Weight Fraction in Crude (wt%/100)	Total Light Liquid TOC Fugitive Losses (tpy)	Component Emission Rate/Loss (tpy)	Total HAP Light Liquid Fugitive Emissions/Losses (tpy)
Methane	0	45	0.0	N/A
Ethane	0.0002	45	0.01	N/A
Propane	0.003	45	0.1	N/A
Isobutane	0.0044	45	0.2	N/A
N-Butane	0.0152	45	0.7	N/A
1,3 Butadiene	0	45	0	0
Isopentane	0.0088	45	0.4	N/A
N-Pentane	0.0127	45	0.6	N/A
N-Hexane	0.0104	45	0.5	0.47
Hexanes	0.0118	45	0.5	N/A
Benzene	0.0033	45	0.1	0.15
Heptanes	0.0392	45	1.8	N/A
2,2,4 Trimethylpentane	0	45	0	0
Toluene	0.0084	45	0.4	0.38
Octanes	0.0464	45	2.1	N/A
Ethyl Benzene	0.002	45	0.1	0.09
Xylenes	0.0095	45	0.4	0.43
Isopropylbenzene	0.0005	45	0.02	0.02
Nonanes	0.031	45	1.4	N/A
Naphthalene	0.0016	45	0.07	0.07
Decanes+	0.7916	45	35.6	N/A
Total Potential HAP Emissions:	**1.0**		**45**	**1.6**

Table D3-12. Actual Annual Emissions Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Piping Fugitives - Gas/Vapor Service

1. Assume that the TOC emissions (losses) are determined from emission factors in Protocol for Equipment Leak Estimates, EPA-453-95-017, November 1995.

2. Based on this protocol, and a TAPs facilities fugitive emissions study conducted by Alyeska in 1998, the potential TOC emissions for PS 4 are estimated to be:
   176 tpy (Gas/Vapor Service)

3. Assuming that the gas/vapor piping leaks are all associated with fuel gas, the individual component emission rates (losses) are then determined using the weight fractions previously calculated.

Calculation of Component Emission Rates (Losses) - Gas/Vapor Service					
Component	Component Weight Fraction in Fuel Gas	Normalized Component Weight Fraction in Fuel Gas	Total Gas/Vapor TOC Fugitive Losses (tpy)	Component Emission Rate/Loss (tpy)	Total HAP Fuel Gas Fugitive Emissions/Losses (tpy)
Methane	0.56826	0.77321	176	136.1	N/A
Ethane	0.07875	0.10715	176	18.9	N/A
Propane	0.04214	0.05734	176	10.1	N/A
Isobutane	0.03578	0.04869	176	8.6	N/A
N-Butane	0.00614	0.00836	176	1.5	N/A
1,3 Butadiene	0.00000	0.00000	176	0.00	0.00
Isopentane	0.00099	0.00135	176	0.24	N/A
N-Pentane	0.00099	0.00135	176	0.24	N/A
N-Hexane	0.00020	0.00027	176	0.05	0.05
Hexanes+	0.00118	0.00161	176	0.28	N/A
Benzene	0.00007	0.00010	176	0.02	0.02
2,2,4 Trimethylpentane	0.00000	0.00000	176	0.00	0.00
Toluene	0.00042	0.00058	176	0.10	0.10
Ethyl Benzene	0.00000	0.00000	176	0.00	0.00
Xylenes	0.00000	0.00000	176	0.00	0.00
Isopropylbenzene	0.00000	0.00000	176	0.00	0.00
Napthalene	0.00000	0.00000	176	0.00	0.00
Total Potential HAP Emissions:	**0.73**	**1.0**		**176**	**0.2**

Notes:
1. The component weight fractions in the fuel gas were normalized to eliminate the non-organic components N_2 and CO_2.

Table D3-13. Actual Annual Emissions Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Diesel Engines Less Than 600 Horsepower

Maximum Total Heat Input: **4.9** **MMBtu/yr** [1]

Section 112 Hazardous Air Pollutants			Source Category Emission Calculations	
No.	**CAS No.**	**Chemical Name**	**Emission Factor** [2]	**Estimated Emissions**
1	75070	Acetaldehyde	7.67E-04 lb/MMBtu	1.87E-06 tpy
6	107028	Acrolein	9.25E-05 lb/MMBtu	2.26E-07 tpy
15	71432	Benzene	9.33E-04 lb/MMBtu	2.28E-06 tpy
23	106990	1,3-Butadiene	3.91E-05 lb/MMBtu	9.54E-08 tpy
87	5000	Formaldehyde	1.18E-03 lb/MMBtu	2.88E-06 tpy
152	108883	Toluene	4.09E-04 lb/MMBtu	9.98E-07 tpy
169	1330207	Xylenes (isomers and mixture)	2.85E-04 lb/MMBtu	6.96E-07 tpy
187	N/A	Polycyclic Organic Matter (POM)	1.68E-04 lb/MMBtu	4.10E-07 tpy
		Polycyclic aromatic compounds(PAH)		4.10E-07 tpy
119	91203	Naphthalene	8.48E-05 lb/MMBtu	2.07E-07 tpy
		Acenaphthylene	5.06E-06 lb/MMBtu	1.23E-08 tpy
		Acenaphthene	1.42E-06 lb/MMBtu	3.47E-09 tpy
		Fluorene	2.92E-05 lb/MMBtu	7.13E-08 tpy
		Phenanthrene	2.94E-05 lb/MMBtu	7.18E-08 tpy
		Anthracene	1.87E-06 lb/MMBtu	4.56E-09 tpy
		Fluoranthene	7.61E-06 lb/MMBtu	1.86E-08 tpy
		Pyrene	4.78E-06 lb/MMBtu	1.17E-08 tpy
		Benzo(a)anthracene	1.68E-06 lb/MMBtu	4.10E-09 tpy
		Chrysene	3.53E-07 lb/MMBtu	8.62E-10 tpy
		Benzo(b)fluoranthene	9.91E-08 lb/MMBtu	2.42E-10 tpy
		Benzo(k)fluoranthene	1.55E-07 lb/MMBtu	3.78E-10 tpy
		Benzo(a)pyrene	1.88E-07 lb/MMBtu	4.59E-10 tpy
		Indeno(1,2,3-cd)pyrene	3.75E-07 lb/MMBtu	9.15E-10 tpy
		Dibenz(a,h)anthracene	5.83E-07 lb/MMBtu	1.42E-09 tpy
		Benzo(g,h,l)perylene	4.89E-07 lb/MMBtu	1.19E-09 tpy
			Total Actual HAP Emissions:	**0.00 tpy**

Notes:
[1] Total fuel use based on maximum full-time operation as noted below.

EU ID 15 Generator Engine	0.6 MMBtu/hr
	8 hrs/yr
Actual Heat Input:	5 MMBtu/yr
Total Actual Heat Input:	**5 MMBtu/yr**
Engines heat rate:	7,000 Btu/hp-hr
Diesel average heat value: Table 3.1-2a, AP-42.	139 MMBtu/10^3 gallons

[2] Reference: AP-42, Table 3.3-2.

Table D3-14. Actual Annual Emissions Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Diesel Engines Greater Than or Equal to 600 Horsepower

Maximum Total Heat Input: **67.6 MMBtu/yr** [1]

CAS No.	Chemical Name	Source Category Emission Calculations: Emission Factor [2]	Estimated Emissions
75-07-0	Acetaldehyde	2.52E-05 lb/MMBtu	8.52E-07 tpy
107-02-8	Acrolein	7.88E-06 lb/MMBtu	2.66E-07 tpy
71-43-2	Benzene	7.76E-04 lb/MMBtu	2.62E-05 tpy
50-00-0	Formaldehyde	7.89E-05 lb/MMBtu	2.67E-06 tpy
108-88-3	Toluene	2.81E-04 lb/MMBtu	9.50E-06 tpy
1330-20-7	Xylenes (isomers and mixture)	1.93E-04 lb/MMBtu	6.52E-06 tpy
N/A	Polycyclic Organic Matter (POM)	2.12E-04 lb/MMBtu	7.15E-06 tpy
	Polycyclic aromatic compounds(PAH)		7.15E-06 tpy
	Acenaphthene	4.68E-06 lb/MMBtu	1.58E-07 tpy
	Acenaphthylene	9.23E-06 lb/MMBtu	3.12E-07 tpy
	Anthracene	1.23E-06 lb/MMBtu	4.16E-08 tpy
	Benzo(a)anthracene	6.22E-07 lb/MMBtu	2.10E-08 tpy
	Benzo(b)fluoranthene	1.11E-06 lb/MMBtu	3.75E-08 tpy
	Benzo(k)fluoranthene	2.18E-07 lb/MMBtu	7.37E-09 tpy
	Benzo(a)pyrene	2.57E-07 lb/MMBtu	8.68E-09 tpy
	Benzo(g,h,l)perylene	5.56E-07 lb/MMBtu	1.88E-08 tpy
	Chrysene	1.53E-06 lb/MMBtu	5.17E-08 tpy
	Dibenz(a,h)anthracene	3.46E-07 lb/MMBtu	1.17E-08 tpy
	Fluoranthene	4.03E-06 lb/MMBtu	1.36E-07 tpy
	Fluorene	1.28E-05 lb/MMBtu	4.33E-07 tpy
	Indeno(1,2,3-cd)pyrene	4.14E-07 lb/MMBtu	1.40E-08 tpy
91-20-3	Naphthalene	1.30E-04 lb/MMBtu	4.39E-06 tpy
	Phenanthrene	4.08E-05 lb/MMBtu	1.38E-06 tpy
	Pyrene	3.71E-06 lb/MMBtu	1.25E-07 tpy
		TOTAL	**5.32E-05 tpy**

Notes:
[1] Total fuel use based on maximum full-time operation or permit-limited operation as noted below:

EU ID 14	Generator Engine		21.1 MMBtu/hr
			0 hrs/yr
		Actual Heat Input:	0 MMBtu/yr
EU ID 22	Generator Engine		7.5 MMBtu/hr
			9 hrs/yr
		Actual Heat Input:	68 MMBtu/yr
		Total Actual Heat Input:	**68 MMBtu/yr**
Engines heat rate:			7,000 Btu/hp-hr

[2] Reference: AP-42, Table 3.4-3 and Table 3.4-4

Table D3-15. Actual Annual Emissions Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Insignificant Emission Units - Natural Gas Fired Heaters

73,812 MMBtu/yr [1]

CAS No.	Chemical Name	AP-42 Emission Factor [2] (Source Category Emission Calculations)	Actual Emissions [3] (Source Category Emission Calculations)
91-57-6	2-Methylnapthalene	2.40E-05 lb/MMscf	8.68E-07 tpy
56-49-5	3-Methylcholanthrene	1.80E-06 lb/MMscf	6.51E-08 tpy
	7,12-Dimethylbenz(a)anthracene	1.60E-05 lb/MMscf	5.79E-07 tpy
83-32-9	Acenaphthene	1.80E-06 lb/MMscf	6.51E-08 tpy
203-96-8	Acenaphthylene	1.80E-06 lb/MMscf	6.51E-08 tpy
120-12-7	Anthracene	2.40E-06 lb/MMscf	8.68E-08 tpy
56-55-3	Benz(a)anthracene	1.80E-06 lb/MMscf	6.51E-08 tpy
71-43-2	Benzene	2.10E-03 lb/MMscf	7.60E-05 tpy
50-32-8	Benzo(a)pyrene	1.20E-06 lb/MMscf	4.34E-08 tpy
205-99-2	Benzo(b)fluoranthene	1.80E-06 lb/MMscf	6.51E-08 tpy
191-24-2	Benzo(g,h,i)perylene	1.20E-06 lb/MMscf	4.34E-08 tpy
207-08-9	Benzo(k)fluoranthene	1.80E-06 lb/MMscf	6.51E-08 tpy
218-01-9	Chrysene	1.80E-06 lb/MMscf	6.51E-08 tpy
53-70-3	Dibenzo(a,h)anthracene	1.20E-06 lb/MMscf	4.34E-08 tpy
25321-22-6	Dichlorobenzene	1.20E-03 lb/MMscf	4.34E-05 tpy
206-44-0	Fluoranthene	3.00E-06 lb/MMscf	1.09E-07 tpy
86-73-7	Fluorene	2.80E-06 lb/MMscf	1.01E-07 tpy
50-00-0	Formaldehyde	7.50E-02 lb/MMscf	2.71E-03 tpy
110-54-3	Hexane	1.80E+00 lb/MMscf	6.51E-02 tpy
193-39-5	Indeno(1,2,3-cd)pyrene	1.80E-06 lb/MMscf	6.51E-08 tpy
91-20-3	Naphthalene	6.10E-04 lb/MMscf	2.21E-05 tpy
85-01-8	Phenanathrene	1.70E-05 lb/MMscf	6.15E-07 tpy
129-00-0	Pyrene	5.00E-06 lb/MMscf	1.81E-07 tpy
108-88-3	Toluene	3.40E-03 lb/MMscf	1.23E-04 tpy
7440-38-2	Arsenic	2.00E-04 lb/MMscf	7.24E-06 tpy
7440-41-7	Beryllium	1.20E-05 lb/MMscf	4.34E-07 tpy
7440-43-9	Cadmium	1.10E-03 lb/MMscf	3.98E-05 tpy
7440-47-3	Chromium	1.40E-03 lb/MMscf	5.07E-05 tpy
7440-48-4	Cobalt	8.40E-05 lb/MMscf	3.04E-06 tpy
7439-96-5	Manganese	3.80E-04 lb/MMscf	1.37E-05 tpy
7439-97-6	Mercury	2.60E-04 lb/MMscf	9.41E-06 tpy
7440-02-0	Nickel	2.10E-03 lb/MMscf	7.60E-05 tpy
7782-49-2	Selenium	2.40E-05 lb/MMscf	8.68E-07 tpy
		Total Actual HAP Emissions:	**6.83E-02 tpy**

Notes:
[1] Total fuel use based on maximum full-time operation as noted below.

Insignificant EUs	Various	8.4	MMBtu/hr
		8,760	hr/yr
	Actual Heat Input:	73,812	MMBtu/yr
	Total Actual Heat Input:	**73,812**	**MMBtu/yr**

[2] Reference: AP-42, Tables 1.4-3 and 1.4-4.
[3] Natural Gas High Heat Value: AP-42 Table 1.4-2, 3.1-2a 1,020 Btu/scf

Table D3-16. Actual Annual Emissions Calculations - Hazardous Air Pollutant (HAP)
Alyeska Pipeline Services Company - Pump Station 4
Insignificant Emission Units - Diesel Fired Heaters

Actual Total Heat Input for Insignificant Emissions Units: **32,412** **MMBtu/yr** [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**AP-42 Emission Factor** [2]	**Actual Emissions**
N/A	Arsenic Compounds	4.00E-06 lb/MMBtu	6.48E-05 tpy
71-43-2	Benzene	2.10E-04 lb/MMBtu	3.40E-03 tpy
N/A	Beryllium Compounds	3.00E-06 lb/MMBtu	4.86E-05 tpy
N/A	Cadmium Compounds	3.00E-06 lb/MMBtu	4.86E-05 tpy
N/A	Chromium Compounds	3.00E-06 lb/MMBtu	4.86E-05 tpy
100-41-4	Ethyl benzene	6.36E-05 lb/MMBtu	1.03E-03 tpy
50-00-0	Formaldehyde	3.30E-02 lb/MMBtu	5.35E-01 tpy
N/A	Lead Compounds	9.00E-06 lb/MMBtu	1.46E-04 tpy
N/A	Manganese Compounds	6.00E-06 lb/MMBtu	9.72E-05 tpy
N/A	Mercury Compounds	3.00E-06 lb/MMBtu	4.86E-05 tpy
N/A	Nickel Compounds	3.00E-06 lb/MMBtu	4.86E-05 tpy
N/A	Selenium Compounds	1.50E-05 lb/MMBtu	2.43E-04 tpy
108-88-3	Toluene	6.20E-03 lb/MMBtu	1.00E-01 tpy
71-55-6	1,1,1-Trichloroethane	2.36E-04 lb/MMBtu	3.82E-03 tpy
1330-20-7	Xylenes	1.09E-04 lb/MMBtu	1.77E-03 tpy
N/A	Polycyclic Organic Matter (POM)		2.34E-02 tpy
N/A	Polycyclic aromatic compounds(PAH)		2.34E-02 tpy
208-96-8	Acenaphthene	2.11E-05 lb/MMBtu	3.42E-04 tpy
83-32-9	Acenaphthylene	2.53E-04 lb/MMBtu	4.10E-03 tpy
120-12-7	Anthracene	1.22E-06 lb/MMBtu	1.98E-05 tpy
56-55-3	Benzo(a)anthracene	4.01E-06 lb/MMBtu	6.50E-05 tpy
205-99-2	Benzo(b,k)fluoranthene	1.48E-06 lb/MMBtu	2.40E-05 tpy
191-24-2	Benzo(g,h,i)perylene	2.26E-06 lb/MMBtu	3.66E-05 tpy
218-01-9	Chrysene	2.38E-06 lb/MMBtu	3.86E-05 tpy
53-70-3	Dibenz(a,h)anthracene	1.67E-06 lb/MMBtu	2.71E-05 tpy
206-44-0	Fluoranthene	4.84E-06 lb/MMBtu	7.84E-05 tpy
86-73-7	Fluorene	4.47E-06 lb/MMBtu	7.24E-05 tpy
193-39-5	Indeno(1,2,3-cd)pyrene	2.14E-06 lb/MMBtu	3.47E-05 tpy
91-20-3	Naphthalene	1.13E-03 lb/MMBtu	1.83E-02 tpy
85-01-8	Phenanthrene	1.05E-05 lb/MMBtu	1.70E-04 tpy
129-00-0	Pyrene	4.25E-06 lb/MMBtu	6.89E-05 tpy
		Total Actual HAP Emissions:	**6.69E-01 tpy**

Notes:

[1] Total fuel use based on maximum full-time operation as noted below.

Insignificant EUs	Various	3.7	MMBtu/hr
		8,760	hr/yr
	Actual Heat Input:	32,412	MMBtu/yr
	Total Actual Heat Input:	**32,412**	**MMBtu/yr**

[2] Reference: AP-42, Tables 1.3-9 and 1.3-10

Table D3-17a. Estimating Procedure for Determining HAP Content of Crude Storage Tank Vapors
Alyeska Pipeline Services Company - Pump Station 4

I. Sample Description/Comments

1. PS 1 discharge stream sample (sample date: 10/31/02)
2. Sample Date: 10/31/02
3. Sample ID: L1-021031-06
4. Core Laboratories data includes crude molecular weight and component wt% values.

II. Determine Component Mole Fractions in Liquid Crude

Methodology Assumptions/Comments:
1. The component mole fraction in crude is determined from component weight fraction and component molecular weight by assuming a mass of 1,000 lb of crude (see AP-42 Section 7.1.5).

2. The component molecular weight of Decanes+ is equal to the value required for the sum of all molecular weights to be equal to the Core Laboratories measured crude molecular weight of: 232 lb/lb-mole

Liquid Crude Analysis Data		Calculate Component Mole Fraction in Crude			
Component **i**	Component Weight Fraction in Crude (wt%/100) $\mathbf{Z_{Li}}$	Component Molecular Weight $\mathbf{M_i}$	Total Moles of Crude (sum ZL_i/M x 1000) $\mathbf{x_T}$	Component Mole Fraction in Crude ($Z_{Li}/M_i/x_T$) $\mathbf{x_i}$	Crude Molecular Weight (sum M_i*x_i) $\mathbf{M_T}$
Methane	0	16	0.000	0.000	0.000
Ethane	0.0002	30	0.007	0.002	0.046
Propane	0.003	44	0.068	0.016	0.696
Isobutane	0.0044	58	0.076	0.018	1.021
N-Butane	0.0152	58	0.262	0.061	3.529
1,3 Butadiene	0	54	0.000	0.000	0.000
Isopentane	0.0088	72	0.122	0.028	2.043
N-Pentane	0.0127	72	0.176	0.041	2.948
N-Hexane	0.0104	86	0.121	0.028	2.414
Hexanes	0.0118	84	0.140	0.033	2.739
Benzene	0.0033	78	0.042	0.010	0.766
Heptanes	0.0392	97	0.404	0.094	9.100
2,2,4 Trimethylpentane	0	114	0.000	0.000	0.000
Toluene	0.0084	92	0.091	0.021	1.950
Octanes	0.0464	111	0.418	0.097	10.771
Ethyl Benzene	0.002	106	0.019	0.004	0.464
Xylenes	0.0095	106	0.090	0.021	2.205
Isopropylbenzene	0.0005	120	0.004	0.001	0.116
Nonanes	0.031	123	0.252	0.059	7.196
Naphthalene	0.0016	128	0.012	0.003	0.371
Decanes+	0.7916	395	2.004	0.465	183.76
SUM Z_{Li} / x_T / x_i / M_T	1.00		4.308	1.000	232

Notes:
1. Molecular weight values for component groups such as octanes are estimates from Core Laboratories.

Table D3-17b. Estimating Procedure for Determining HAP Content of Crude Storage Tank Vapors
Alyeska Pipeline Services Company - Pump Station 4

III. Determine Component Vapor Pressure at Given Crude Temperature

Methodology Assumptions/Comments:

1. Clausius-Clapeyron equation provides relationship between temperature and vapor pressure:

$$\log P_2/P_1 = H_v/2.303R*(T_2-T_1/T_2T_1)$$

where R = Universal Gas Constant = 8.31448 J/g-mole·K = 3.58 Btu/lb-mole·K
Hv = Heat of Vaporization = see table below

2. Let P_1 be known component vapor pressure at known temperature T_1 = 100 F (311 K),
and P_2 be unknown component vapor pressure at given crude temperature T_2 (shown below).

3. PS 3 crude (and vapor) constant temperature (P_2) of: 102 F 312 K
Based on average crude temperature at PS 4 during peak flow year 1995.

Component Physical Properties			Component Vapor Pressure at Crude Temperature			
Component **i**	Component Vapor Pressure at 100F (psia **P_1**	Component Heat of Vaporization (Btu/lb-mole) **H_v**	Component Heat of Vaporization / Gas Constant $H_v/2.303R$	Calculate $(T_2-T_1)/T_2T_1$	Calculate Inverse Log of $(H_v/2.303R)$ * $(T_2-T_1)/T_2T_1$	Component Vapor Pressure at Crude Temperature (psia) **P_2**
Methane	5000	3520	426.9	0.00001	1.011	5056
Ethane	800	6349	770.1	0.00001	1.020	816
Propane	189	8071	978.9	0.00001	1.026	194
Isobutane	72.6	9136	1108.2	0.00001	1.030	74.7
N-Butane	51.7	9642	1169.5	0.00001	1.031	53.3
1,3 Butadiene	59.5	10025	1215.9	0.00001	1.033	61.4
Isopentane	20.4	10613	1287.3	0.00001	1.034	21.1
N-Pentane	15.6	11082	1344.2	0.00001	1.036	16.2
N-Hexane	4.96	12404	1504.5	0.00001	1.040	5.16
Hexanes	10	12500	1516.1	0.00001	1.041	10.41
Benzene	3.22	13215	1602.8	0.00001	1.043	3.36
Heptanes	3.5	13500	1637.4	0.00001	1.044	3.65
2,2,4 Trimethylpentane	1.70	14000	1698.1	0.00001	1.046	1.8
Toluene	1.03	14263	1730.0	0.00001	1.047	1.08
Octanes	1	14500	1758.7	0.00001	1.047	1.05
Ethyl Benzene	0.37	15288	1854.3	0.00001	1.050	0.39
Xylenes	0.33	16000	1940.6	0.00001	1.052	0.35
Isopropylbenzene	0.19	16136	1957.1	0.00001	1.053	0.20
Nonanes	0.40	16500	2001.3	0.00001	1.054	0.42
Naphthalene	0.13	16700	2025.5	0.00001	1.055	0.14
Decanes+	0.1	47282	5734.7	0.00001	1.163	0.12

Notes:
1. Heat of Vaporization and vapor pressure of pure components from GPSA Engineering Data Book, Volume II, Section 23.
2. Vapor pressure values for component groups such as octanes are estimates from Core Laboratories.
3. Heat of Vaporization for component groups are estimates based on values for individual components within the group.

Table D3-17c. Estimating Procedure for Determining HAP Content of Crude Storage Tank Vapors
Alyeska Pipeline Services Company - Pump Station 4

IV. Determine Component Partial Pressure and Mole Fraction in Crude Vapor

Methodology Assumptions/Comments:

1. Conservatively assume C_1-C_{10} hydrocarbons and HAPs are only species present in vapor phase due to dramatic dropoff in component vapor pressue as component molecular weight increases.

2. For speciation purposes, assume crude vapor pressure (P_{VA}) equal to sum of component partial pressures indicated below. This assumption ignores CO_2 present in crude and is conservative because it results in vapor mole fractions of listed components (including HAPs) being overstated.

3. Component partial pressure is equal to the component mole fraction in the liquid crude multiplied by the component vapor pressure at the given crude temperature:

$$P_i = P_2 * x_i$$

4. The component mole fraction in the crude vapor is then equal to the component partial pressure divided by the overall crude vapor pressure:

$$y_i = P_i / P_{VA}$$

	Calculation of Component Partial Pressure and Mole Fraction in Vapor			
Component **i**	Component Vapor Pressure at Crude Temperature (psia **P_2**	Component Mole Fraction in Crude ($Z_{Li}/M_i/x_T$) **x_i**	Component Partial Pressure at Crude Temperature (P_2*x_i) **P_i**	Component Mole Fraction in Vapor (P_i/P_{VA}) **y_i**
Methane	5056	0.0000	0.000	0.0000
Ethane	816	0.0015	1.260	0.1126
Propane	194	0.0158	3.057	0.2729
Isobutane	74.7	0.0176	1.314	0.1173
N-Butane	53.3	0.0607	3.237	0.2890
1,3 Butadiene	61.4	0.0000	0.000	0.0000
Isopentane	21.1	0.0283	0.599	0.0535
N-Pentane	16.2	0.0409	0.660	0.0590
N-Hexane	5.16	0.0280	0.145	0.0129
Hexanes	10.41	0.0326	0.339	0.0303
Benzene	3.36	0.0098	0.033	0.0029
Heptanes	3.65	0.0938	0.343	0.0306
2,2,4 Trimethylpentane	1.78	0.0000	0.000	0.0000
Toluene	1.08	0.0212	0.023	0.0020
Octanes	1.05	0.0970	0.102	0.0091
Ethyl Benzene	0.39	0.0044	0.002	0.0002
Xylenes	0.35	0.0208	0.007	0.0006
Isopropylbenzene	0.20	0.0010	0.000	0.0000
Nonanes	0.42	0.0585	0.025	0.0022
Naphthalene	0.14	0.0029	0.000	0.0000
Decanes+	0.12	0.4652	0.054	0.0048
P_{VA} / y_i SUM			11.2	1.00

Table D3-17d. Estimating Procedure for Determining HAP Content of Crude Storage Tank Vapors
Alyeska Pipeline Services Company - Pump Station 4

V. Determine Component Weight Fractions in Crude Vapor

1. Component weight fraction in the vapor is determined in two steps. First, the overall vapor molecular weight is determined by summing the product of the molecular weight and vapor mole fraction for each component:

$$M_V = \text{sum } (M_i{*}y_i)$$

2. Then, the component weight fraction is determined by dividing the product of the molecular weight and vapor mole fraction for each component by the overall vapor molecular weight:

$$Z_{Vi} = (M_i{*}y_i)/M_V$$

Component Physical Properties		Calculation of Component Weight Fraction in Vapor		
Component **i**	Component Molecular Weight **M_i**	Component Mole Fraction in Vapor (P_i/P_{VA}) **y_i**	Calculate Vapor Molecular Weight (sum $M_i{*}y_i$) **M_V**	Component Weight Fraction in Vapor ($Mi{*}y_i/M_V$) **Z_{Vi}**
Methane	16	0.0000	0.00	0.0000
Ethane	30	0.1126	3.38	0.0589
Propane	44	0.2729	12.04	0.2094
Isobutane	58	0.1173	6.82	0.1186
N-Butane	58	0.2890	16.80	0.2923
1,3 Butadiene	54	0.0000	0.00	0.0000
Isopentane	72	0.0535	3.86	0.0671
N-Pentane	72	0.0590	4.25	0.0740
N-Hexane	86	0.0129	1.11	0.0194
Hexanes	84	0.0303	2.55	0.0443
Benzene	78	0.0029	0.23	0.0040
Heptanes	97	0.0306	2.97	0.0517
2,2,4 Trimethylpentane	114	0.0000	0.00	0.0000
Toluene	92	0.0020	0.19	0.0033
Octanes	111	0.0091	1.01	0.0175
Ethyl Benzene	106	0.0002	0.02	0.0003
Xylenes	106	0.0006	0.07	0.0012
Isopropylbenzene	120	0.0000	0.00	0.0000
Nonanes	123	0.0022	0.27	0.0047
Naphthalene	128	0.0000	0.00	0.0001
Decanes+	395	0.0048	1.91	0.0332
y_i SUM / M_v / Z_{vi} SUM		1.00	57.5	1.00

Table D3-18. Actual Annual Emissions Calculations - Greenhouse Gas (GHG) Emissions Summary
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel Type	Actual Greenhouse Gas Emissions (tpy)				
ID	Description	Rating/Capacity		CO_2	CH_4	N_2O	GHG Mass	GHG CO_2e [1]
Significant Emissions Units								
11	Boiler	1.7 MMBtu/hr	Natural Gas	5,739	0.1	0.01	5,739	5,745
			Diesel	0	0	0	0	0
12	Boiler	1.7 MMBtu/hr	Natural Gas	0	0	0	0	0
			Diesel	0	0	0	0	0
18	Cyclone Turbine	12.9 MW	Natural Gas	29,112	1	5.5E-02	29,112	29,142
			Diesel	0	0	0	0	0
19	Cyclone Turbine	12.9 MW	Natural Gas	25,064	0.5	0.05	25,064	25,089
20	Generator Engine	2,250 kW	Diesel	0	0	0	0	0
21	Generator Engine	65 kW	Diesel	0.4	1.6E-05	3.2E-06	0.4	0.4
26	Breakout Tank 130	150,000 bbl	N/A	0	0	0	0	0
27	Generator Engine	800 kW	Diesel	5.5	2.2E-04	4.5E-05	5.5	5.5
Significant Emissions Units Emissions - Greenhouse Gases							**59,921**	**59,982**
Insignificant Emissions Unit								
N/A	Heater	0.763 MMBtu/hr	Natural Gas	390	0.007	7.4E-04	390	391
N/A	Heater	0.763 MMBtu/hr	Natural Gas	390	0.007	7.4E-04	390	391
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.300 MMBtu/hr	Natural Gas	153	0.003	2.9E-04	153	154
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Natural Gas	256	0.005	4.8E-04	256	256
N/A	Heater	0.500 MMBtu/hr	Diesel	356	0.01	0.003	356	358
N/A	Heater	0.600 MMBtu/hr	Diesel	428	0.02	0.003	428	429
N/A	Heater	0.600 MMBtu/hr	Diesel	428	0.02	0.003	428	429
N/A	Heater	0.800 MMBtu/hr	Diesel	570	0.02	0.005	570	572
N/A	Heater	0.800 MMBtu/hr	Diesel	570	0.02	0.005	570	572
N/A	Heater	0.400 MMBtu/hr	Diesel	285	0.01	0.002	285	286
Insignificant Emissions Unit Emissions - Greenhouse Gases							**6,945**	**6,958**
Total Emissions - Greenhouse Gases							**66,867**	**66,940**

Notes:
[1] GHG emissions are defined as CO2e emissions.
Per 40 CFR 98. Table A-1. Please note CO2e is the summation of CO2 (1), CH4 (28), and N2O (265), applying the global warming Actual for each pollutant.

Table D3-19. Actual Annual Emissions Calculations - Carbon Dioxide (CO_2)
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel	Factor	CO_2 Emission	Actual	Actual
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	CO_2 Emissions [1]
Significant Emissions Units							
8	Heater	20.6 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	96 MMscf/yr	5,739 tpy
			Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	0 gal/yr	0 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	0 MMscf/yr	0 tpy
			Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	0 gal/yr	0 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	489 MMscf/yr	29,112 tpy
			Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	0 gal/yr	0 tpy
13	Cyclone Turbine	12.9 MW	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	421 MMscf/yr	25,064 tpy
14	Generator Engine	2,250 kW	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	0 hrs/yr	0 tpy
15	Generator Engine	65 kW	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8 hrs/yr	0.4 tpy
21	Breakout Tank 140	150,000 bbl	N/A	N/A	N/A	8,760 hrs/yr	N/A
22	Generator Engine	800 kW	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	9 hrs/yr	5.5 tpy
						Significant Emissions Units Emissions - CO_2	**59,920 tpy**
Insignificant Emissions Units							
N/A	Heater	0.763 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	390 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	390 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	153 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hours	256 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours	356 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours	428 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours	428 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours	570 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours	570 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	8,760 hours	285 tpy
						Insignificant Emissions Units Emissions - CO_2	**6,945 tpy**
						Total Emissions - CO_2	**66,865 tpy**

Notes:
[1] Parameters and conversions:

Natural Gas High Heat Value: AP-42 Table 1.4-1, 3.1-1	1,020 Btu/scf
Diesel High Heat Value: AP-42 Table 1.3-1	139 MMBtu/1000 gal
Average BSFC, Table 3.4-1, AP-42	7,000 Btu/hp-hr

Table D3-20. Actual Annual Emissions Calculations - Methane (CH4)
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit ID	Description	Rating/Capacity	Fuel Type	Factor Reference	CH_4 Emission Factor	Actual Operation	Actual CH_4 Emissions [1]
Significant Emissions Units							
8	Heater	20.6 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	96 MMscf/yr	0.11 tpy
			Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	0 gal/yr	0 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	0 MMscf/yr	0 tpy
			Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	0 gal/yr	0 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	489 MMscf/yr	0.55 tpy
			Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	0 gal/yr	0 tpy
13	Cyclone Turbine	12.9 MW	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	421 MMscf/yr	0.47 tpy
14	Generator Engine	2,250 kW	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	0 hrs/yr	0 tpy
15	Generator Engine	65 kW	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8 hrs/yr	1.6E-05 tpy
21	Breakout Tank 140	150,000 bbl	N/A	N/A	N/A	8,760 hrs/yr	N/A
22	Generator Engine	800 kW	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	9 hrs/yr	2.2E-04 tpy
						Significant Emissions Units Emissions - CH_4	**1.13 tpy**
Insignificant Emissions Units							
N/A	Heater	0.763 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	7.4E-03 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	7.4E-03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	2.9E-03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	2.9E-03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	2.9E-03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	2.9E-03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	2.9E-03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	2.9E-03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	2.9E-03 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	2.9E-03 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	4.8E-03 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	4.8E-03 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	4.8E-03 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	4.8E-03 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	4.8E-03 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	4.8E-03 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	4.8E-03 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	4.8E-03 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.001 kg/MMBtu	8,760 hours	4.8E-03 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours	1.4E-02 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours	1.7E-02 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours	1.7E-02 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours	2.3E-02 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours	2.3E-02 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.003 kg/MMBtu	8,760 hours	1.2E-02 tpy
						Insignificant Emissions Units Emissions - CH_4	**0.19 tpy**
						Total Emissions - CH_4	**1.3 tpy**

Notes:
[1] Parameters and conversions:

Natural Gas High Heat Value: AP-42 Table 1.4-1, 3.1-1	1,020	Btu/scf
Diesel High Heat Value: AP-42 Table 1.3-1	139	MMBtu/10^3 gal
Average BSFC, Table 3.4-1, AP-42	7,000	Btu/hp-hr

Table D3-21. Actual Annual Emissions Calculations - Nitrous Oxide (N_2O)
Alyeska Pipeline Services Company - Pump Station 4

Emissions Unit			Fuel	Factor	N_2O Emission	Actual	Actual
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	N_2O Emissions [1]
Significant Emissions Units							
8	Heater	20.6 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	96 MMscf/yr	0.01 tpy
			Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	0 gal/yr	0 tpy
9	Heater	20.6 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	0 MMscf/yr	0 tpy
			Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	0 gal/yr	0 tpy
12	Cyclone Turbine	12.9 MW	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	489 MMscf/yr	0.05 tpy
			Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	0 gal/yr	0 tpy
13	Cyclone Turbine	12.9 MW	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	421 MMscf/yr	0.05 tpy
14	Generator Engine	2,250 kW	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	0 hrs/yr	0 tpy
15	Generator Engine	65 kW	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8 hrs/yr	3.2E-06 tpy
21	Breakout Tank 140	150,000 bbl	N/A	N/A	N/A	8,760 hrs/yr	N/A
22	Generator Engine	800 kW	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	9 hrs/yr	4.5E-05 tpy
						Significant Emissions Units Emissions - N_2O	**0.11 tpy**
Insignificant Emissions Units							
N/A	Heater	0.763 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	7.4E-04 tpy
N/A	Heater	0.763 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	7.4E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.9E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.9E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.9E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.9E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.9E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.9E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.9E-04 tpy
N/A	Heater	0.300 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	2.9E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.8E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.8E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.8E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.8E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.8E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.8E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.8E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.8E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Natural Gas	40 CFR 98, Table C-2	0.0001 kg/MMBtu	8,760 hours	4.8E-04 tpy
N/A	Heater	0.500 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours	2.9E-03 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours	3.5E-03 tpy
N/A	Heater	0.600 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours	3.5E-03 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours	4.6E-03 tpy
N/A	Heater	0.800 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours	4.6E-03 tpy
N/A	Heater	0.400 MMBtu/hr	Diesel	40 CFR 98, Table C-2	0.0006 kg/MMBtu	8,760 hours	2.3E-03 tpy
						Insignificant Emissions Units Emissions - N_2O	**0.030 tpy**
						Total Emissions - N_2O	**0.1 tpy**

Notes:
[1] Parameters and conversions:

Natural Gas High Heat Value: AP-42 Table 1.4-1, 3.1-1	1,020	Btu/scf
Diesel High Heat Value: AP-42 Table 1.3-1	139	MMBtu/10^3 gal
Average BSFC, Table 3.4-1, AP-42	7,000	Btu/hp-hr

Appendix E Regulatory Requirements

Application for Renewal of an Air Quality Operating Permit

Pump Station 4

Alyeska Pipeline Service Company

SLR Project No.: 105.021406.00001

July 25, 2025

E.1 Form E1: Stationary Source - Wide Applicable Requirements

FORM E1
Stationary Source-Wide Applicable Requirements

Permit Number: AQ0075TVP04

Stationary Source-Wide Applicable Requirements (*attach additional sheets as needed*):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
AQ0075TVP04, Condition 46	18 AAC 50.040(b)(1) & (2)(F), 50.326(j) 40 CFR 61, Subparts A & M, and Appendix A	Asbestos NESHAP	The Permittee shall comply with NESHAP Subpart M requirements.	Yes	Advisory Provision
AQ0075TVP04, Condition 47 through 49	18 AAC 50.040(d), 50.326(j) 40 CFR 82 Subparts F, G, H, 82.174(b) – (d), and 82.270(b) – (f)	Refrigerant Recycling and Disposal, Halon Emissions Reduction	Comply with the applicable requirements for Recycling and Emissions Reduction, Significant New Alternatives, & Halons Emissions Reduction	Yes	Reasonable inquiry
AQ0075TVP04, Condition 50	18 AAC 50.040(c)(1), 50.040(j), 50.326(j) 40 CFR 71.6(a)(3)(ii),63.1(b)(3)	NESHAP Applicability Determinations	The Permittee shall determine NESHAP rule applicability.	Yes	Conditions 50.1 through 50.3
AQ0075TVP04, Condition 51	18 AAC 50.326(j)(3), 50.345(a), & (e)	Standard Terms and Conditions	Each permit term and condition is independent and remains valid regardless of a challenge to any other part of the permit.	Yes	Advisory Provision

FORM E1

Stationary Source-Wide Applicable Requirements

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
AQ0075TVP04, Condition 52	18 AAC 50.326(j)(3), 50.345(a), & (f)	Standard Terms and Conditions	Requested permit changes do not stay any permit condition	Yes	Advisory Provision
AQ0075TVP04, Condition 53	18 AAC 50.326(j)(3), 50.345(a), & (g)	Standard Terms and Conditions	The permit does not convey any property rights of any sort	Yes	Advisory Provision
AQ0075TVP04, Condition 54	18 AAC 50.326(j)(1), 50,400 & 50.403 AS 37.10.052(b) & 46.14.240	Administrative Fees	The Permittee shall pay all assessed permit administration fees.	Yes	Advisory Provision
AQ0075TVP04, Condition 55	18 AAC 50.040(j)(3), 50.035, 50.326(j)(1), 50.410, & 50.420 40 CFR 71.5(c)(3)(ii)	Assessable Emissions	The Permittee shall pay the Department an annual emission fee based on the assessable emissions of the source.	Yes	Standard Permit Condition I
AQ0075TVP04, Condition 56	18 AAC 50.040(j)(3), 50.035, 50.326(j)(1), 50.410, & 50.420 40 CFR 71.5(c)(3)(ii)	Assessable Emission Estimates	Calculate assessable emissions and submit them to the Department by March 31 or plan to pay fees based on the potential emissions.	Yes	Standard Permit Condition I
AQ0075TVP04, Condition 58	18 AAC 50.045(a)	Dilution	The Permittee shall not dilute emissions.	Yes	Advisory Provision

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
AQ0075TVP04, Condition 59	18 AAC 50.045(d)	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.	Yes	Standard Permit Condition X
AQ0075TVP04, Condition 60	18 AAC 50.055(g)	Stack Injection	The Permittee shall not release materials other than process emissions, products of combustion or materials introduced to control pollutant emissions from a stack.	Yes	Advisory Provision
AQ0075TVP04, Condition 61	18 AAC 50.110	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 interferes with the enjoyment of life or property.	Yes	Conditions 61.1 through 61.3, Standard Permit Condition II
AQ0075TVP04, Condition 63	18 AAC 50.065, 50.040(j), 50.326(j) 40 CFR 71.6(a)(3)	Open Burning	The Permittee shall comply with the requirements of 18 AAC 50.065.	Yes	Conditions 63.1 and 63.2

FORM E1
Stationary Source-Wide Applicable Requirements

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
AQ0075TVP04, Conditions 64 through 73	18 AAC 50.220(a), (b), (c), (f) & 50.345(a), (k), (l), (m), (n), & (o)	Source Testing Requirements	General source testing and monitoring requirements	Yes	Advisory Provision
AQ0075TVP04, Condition 74	18 AAC 50.040(a)(1), 50.326(j) 40 CFR 60.7(f), Subpart A 40CFR71.6(a)(3)(ii)(B)	Recordkeeping Requirements	The Permittee shall keep all records for at least five years.	Yes	Advisory Provision
AQ0075TVP04, Condition 75	18 AAC 50.345(a)(j), 50.205, 50.326(j)	Certification	The Permittee shall certify all reports, compliance certifications or other documents.	Yes	Standard Permit Condition XVII
AQ0075TVP04, Condition 76	18 AAC 50.326(j) 40 CFR 71.6(a)(3)(iii)(A)	Submittals	The Permittee shall submit two copies of reports, compliance certifications and other submittals require by the permit to the Department.	Yes	Standard Permit Condition XVII
AQ0075TVP04, Condition 77	18 AAC 50.345(a) & (i), 50.200, 50.326(a) & (j)	Information Requests	The Permittee shall furnish to the Department any information requested in writing to determine compliance with the permit.	Yes	Advisory Provision
AQ0075TVP04, Condition 78	18 AAC 50.235(a)(2), 50.240(c), 50.326(j)(3), 50.346(b)(2) & (3)	Excess Emissions and Permit Deviation Reports	The Permittee shall report all emissions or operations that exceed or deviate from the permit.	Yes	Standard Permit Condition III

FORM E1
Stationary Source-Wide Applicable Requirements

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
AQ0075TVP04, Condition 79	18 AAC 50.346(b)(6), 50.326(j) 40 CFR 71.6(a)(3)(iii)(A)	Operating Reports	The Permittee shall report all emissions or operations that exceed or deviate from the permit.	Yes	Conditions 79.1 through 79.5, Standard Permit Condition VII
AQ0075TVP04, Condition 80	18 AAC 50.205, 50.345(a) & (j), 50.326(j) 40 CFR 71.6(c)(5)	Annual Compliance Certification	The Permittee shall compile and submit to the Department an annual compliance certification report.	Yes	Conditions 80.1 through 80.3
AQ0075TVP04, Condition 81	18 AAC 50.346(b)(8), 50.200 40 CFR 51.15, 51.30(a)(1), Appendix A to Subpart A	Emission Inventory Reporting	The Permittee shall conduct Emission Inventory Reporting every three years.	Yes	Conditions 81.1 through 81.5, Standard Permit Condition XV
AQ0075TVP04, Condition 82	18 AAC 50.326(j)(4), 50.040(j) 40 CFR 60.13, 63.10(d), (f) & 71.6(c)(6)	NSPS and NESHAP Reports	The Permittee shall submit to the Department a copy of any NSPS and NESHAP report submitted to the U.S. EPA.	Yes	Conditions 82.1, 82.2, Reasonable inquiry
AQ0075TVP04, Condition 83	18 AAC 50.040(j)(7), 50.326(a), 50.346(b)(7) 40 CFR 71.10(d)(1)	Permit Applications and Submittals	The Permittee shall comply with the requirements for submitting application information to the US Environmental Protection Agency (EPA).	Yes	Conditions 831.1 through 83.4, Standard Permit Condition XIV

FORM E1

Stationary Source-Wide Applicable Requirements

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
AQ0075TVP04, Condition 84	18 AAC 50.040(j)(4), 50.326(j) 40 CFR 71.6(a)(8)	Emissions Trading	No permit revisions shall be required for changes that are provided for in the permit.	Yes	Advisory Provision
AQ0075TVP04, Condition 85	18 AAC 50.040(j)(4), 50.326(j) 40 CFR 71.6(a)(12)	Off Permit Changes	The Permittee shall make changes that are not addressed or prohibited by this permit.	Yes	Conditions 85.1 through 85.4.
AQ0075TVP04, Condition 86	18 AAC 50.040(j)(4), 50.326(j) 40 CFR 71.6(a)(13)	Operational Flexibility	The Permittee may make changes if the changes are not modifications under Title I and do not exceed the allowable emissions.	Yes	Conditions 86.1 through 86.3
AQ0075TVP04, Condition 87	18 AAC 50.040(j)(3), 50.326(c) & (j)(2) 40 CFR 71.5(a)(1)(iii) 71.7(b) & (c)(1)(ii)	Permit Renewal	The Permittee shall submit an application between six and 18 months before the permit expires.	Yes	Advisory Provision
AQ0075TVP04, Conditions 88 through 93	18 AAC 50.040(j), 50.326(j), 50.345(a through d)(h) 40 CFR 71.6(c)(3) 71.5(c)(8)(iii)(B)	General Compliance Requirements	The Permittee shall comply with each permit term and condition and allow the Department access to the facility.	Yes	Advisory Provision

1 Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

E.2 Form E3: Title V Condition Change Request

FORM E3

Title V Condition Change Request

Permit Number: AQ0075TVP04

Title V Permit Information (*attach additional sheets as needed*):

Current Title V Operating Permit Condition	Type of change (revise or remove)	Reason for change	Requested Alaska Title V Operating Permit Condition
Table A and footnote 3	Revise	Remove EU ID 10 from Table A and footnote 3. EU ID 10 was decommissioned in December 2023.	N/A
Condition 6	Revise	Revise the condition to reflect the requirement to conduct PM monitoring as required by Condition 12 that is applicable to EU ID 12.	**PM Monitoring.** The Permittee shall conduct source tests on EU IDs 10, 12, 14, 15, and 22 (when required by Condition 5.2 or 12.3a), to determine the concentration of PM in the exhaust of each emissions unit as follows:
Condition 18	Revise	The permittee has configured EU IDs 12 and 13 with Dry Low Emissions (DLE) Technology. Please remove the sentence reference from the condition.	N/A
Conditions 44, 45, 45.1 through 45.9	Revise	Revise the conditions, as appropriate, to reflect current 40 CFR 63 Subpart ZZZZ language that has been revised during the last permit term.	N/A

Note: Revise Statement of Basis accordingly.

E.3 Form E4: Permit Shield Request

FORM E4

Permit Shield Request

Permit Number:	AQ0075TVP04

Non-applicable requirements (attach additional sheets as needed):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 51 Appendix Y – Guidelines for BART Determinations Under the Regional Haze Rule	PS-4 has been determined not to be a BART eligible source by the Department due to the age vintage of the emissions units.
40 CFR 60 Subpart LLL – Standards of Performance for Onshore Natural Gas Processing Plants	PS-4 does not process natural gas [40 CFR 60.640] and commenced construction prior to the January 20, 1984 effective date of the subpart.
40 CFR 61 Subpart A - General Provisions	Other than the asbestos renovation and demolition requirements of Subpart M this subpart does not apply to this stationary source because it only applies where there are subparts applicable to the stationary source and no other Part 61 subparts apply to this stationary source.
40 CFR 61 Subpart J – National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene	No process components in benzene service, as defined by subpart (10 percent benzene by weight) [40 CFR 61.110 and 61.111].
40 CFR 61 Subpart V – National Emission Standard for Equipment Leaks (Fugitive Emission Sources)	No process components in volatile hazardous air pollutant (VHAP) service, as defined by subpart (≥10 percent VHAP by weight) [40 CFR 61.241 and 61.245]. This subpart only applies where identified by another applicable Part 61 subpart [40 CFR 61.240].
40 CFR 61 Subpart Y – National Emission Standard for Benzene Emissions from Benzene Storage Vessels	The stationary source does not have storage tanks that store benzene as defined by the standards in 40 CFR 61.270(a).
40 CFR 61 Subpart BB – National Emission Standard for Benzene Emissions from Benzene Transfer Operations	Crude oil and petroleum distillates are exempt from this subpart [40 CFR 61.300]. Other than crude oil and other petroleum distillates there are no other benzene containing substances where loading occurs at this stationary source.
40 CFR 61 Subpart FF – National Emission Standard for Benzene Waste Operations	Applies to chemical manufacturing plants, coke byproduct recovery plants and petroleum refineries [40 CFR 61.340]. PS-3 does not include any of those activities.
40 CFR 61 Subpart M – National Emission Standard for Asbestos 40 C.F.R. 61.142 - Standard for Asbestos Mills	Stationary source is not an Asbestos Mill.
40 CFR 61.144 – Standard for Manufacturing	Stationary source does not engage in any manufacturing operations using commercial asbestos.
40 CFR 61.146 – Standard for Spraying	Stationary source does not spray apply asbestos containing materials.
40 CFR 61.147 – Standard for Fabricating	Stationary source does not engage in any fabricating operations using commercial asbestos.

Non-Applicable Requirements[1]	**Reason for non-applicability and citation/basis**
40 CFR 61.149 – Standard for Waste Disposal for Asbestos Mills	Applies only to those facilities subject to 40 CFR 61.142 (Asbestos Mills).
40 CFR 61.151 – Standard for Inactive Waste Disposal Sites for Asbestos Mills and Manufacturing and Fabricating Operations	Applies only to those facilities subject to 40 CFR 61.142, 61.144, or 61.147 (Asbestos Mills, manufacturing or fabricating).
40 CFR 61.153 – Standard for Reporting	No reporting requirements apply for sources subject to 40 CFR 61.145 (demolition and renovation) [40 CFR 61.153(a)].
40 CFR 61.154 – Standard for Active Waste Disposal Sites	Stationary source not an active waste disposal site and does not receive asbestos containing waste material.
40 CFR 61.155 – Standard for Inactive Waste Disposal Sites for Asbestos Mills and Manufacturing and Fabricating Operations	Stationary source does not process regulated asbestos containing material (RACM).
40 CFR 63 Subpart T – National Emission Standards for Halogenated Solvent Cleaning	Stationary source does not operate halogenated solvent cleaning machines.
40 CFR 63 Subpart CCCCCC - NESHAP Source Category for Gasoline Dispensing Facilities (GDF)	Stationary Source does not meet the definition of a Gasoline Dispensing Facility under 40 C.F.R. 63.11132 because gasoline is not dispensed in "motor vehicles" as defined by CAA Section 216.
40 CFR 63 Subpart DDDDD – NESHAP for Industrial/Commercial/Institutional Boilers and Process Heaters	PS-4 is not a major source of HAPs as defined under any subpart of 40 CFR 63.
40 CFR 63 Subpart EEEE – NESHAP for Organic Liquid Distribution (non-gasoline)	PS-4 is not a major source of HAPs as defined under any subpart of 40 CFR 63.
40 CFR 63 Subpart HHHHHH – NESHAP for Paint Stripping and Miscellaneous Surface Coating Operations	MeCl is not used for paint stripping. Painting activities occurring at the stationary source meet the definition of facility maintenance as defined by 40 CFR 63.11180, and thus, are categorically exempt from 63.11170(a)(2) & (3). This shield is not valid if PS-3 operations change in regards to using MeCl.

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 64 – Compliance Assurance Monitoring (CAM)	Stationary source does not contain a pollutant-specific emitting unit that satisfies all of the following criteria: -The emission unit is subject to an applicable emission limitation or standard; -The unit uses a control device to comply with any such applicable emission limitation or standard; and -The unit has potential pre-control device emissions of the applicable regulated air pollutant equal to or greater than the major source thresholds for the applicable regulated air pollutant.
40 CFR 68 – Accidental Release: Risk Management Plan (RMP)	40 CFR Part 68 applies to "stationary sources" [40 CFR 68.10]. "Stationary source" is defined for purposes of Part 68 to exclude stationary sources engaged in the transportation of hazardous liquids and subject to 49 CFR Parts 192, 193, and 195 [40 CFR 68.3]. TAPS PS-4 transports and stores crude oil subject to the federal Pipeline Safety Act and 49 CFR Part 195. The transportation of crude oil by this pump station and the incidental storage in the pump station breakout tank are not activities that fall within the definition of a stationary source. Therefore, Part 68 does not apply to PS-4. There are no threshold quantities or other 112(r) regulated substances at PS-4. Therefore, Part 68 does not apply to PS-4. The fuel gas line is a 49 CFR Part 192 facility and does not fall within the definition of a "stationary source" [40 CFR 68.2]
40 CFR 82.1 Subpart A – Production and Consumption Controls	Stationary source does not produce, transform, destroy, import or export Class 1 or Group I or II substances or products.
40 CFR 82.30 Subpart B – Servicing of Motor Vehicle Air Conditioners	Stationary source does not service motor vehicle air conditioners.
40 CFR 82.60 Subpart C – Ban on Nonessential Products Containing Class I Substances and Ban on Nonessential Products Containing or Manufactured with Class II Substances	Stationary source does not manufacture or distribute Class I and II products or substances.
40 CFR 82.80 Subpart D – Federal Procurement	Subpart applies only to Federal Departments, agencies, and instrumentalities.
40 CFR 82.100 Subpart E – The Labeling of Products Using Ozone-Depleting Substances	Stationary source does not manufacture or distribute Class I and II products or substances.
40 CFR 82.158 Subpart F – Recycling and Emissions Reduction	Stationary source does not manufacture or import recovery and recycling equipment.
40 CFR 82.160 – Recycling and Emissions Reduction	Stationary source does not contract equipment testing organizations to certify recovery and recycling equipment.
40 CFR 82.164 – Recycling and Emissions Reduction	Stationary source does not sell reclaimed refrigerant.

FORM E4

Permit Shield Request

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
18 AAC 50.055(a)(2) - (a)(9)	Stationary source does not operate sources specific to the listed standards.
18 AAC 50.055(b)(2) - (b)(6)	Stationary source does not operate sources specific to the listed standards.
18 AAC 50.055(d) - (f)	Stationary source does not operate sources specific to the listed standards.
18 AAC 50.075	The stationary source does not contain a wood fired heating device.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 CFR 60.332(a)(2).]

E.4 Form E5: Alternative Monitoring Procedures (AMP) Form

FORM E5
Alternative Monitoring Procedures (AMP) Form

Permit Number: AQ0075TVP04

Stationary Source-Wide Alternative Monitoring Procedures and/or EPA Waivers (*attach additional sheets as needed*):

Condition for which AMP or EPA waiver is applicable	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Used to Determine Compliance
Condition 35	SO2	40 CFR 60 Subpart GG	Yes	The Permittee submitted a demonstration to EPA indicating that the fuel gas combusted at the stationary source meets the definition of natural gas in 40 CFR 60.331(u), pursuant to 40 CFR 60.334(h)(3).

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

E.5 Attachment - Alternative Monitoring Procedure Approval

U.S. Environmental Protection Agency
Applicability Determination Index

Control Number: 0700013

Category:	NSPS
EPA Office:	Region 10
Date:	12/11/2006
Title:	Natural Gas Demonstration
Recipient:	Baldridge, John
Author:	KenKnight, Jeff
Comments:	

Part 60, GG	Stationary Gas Turbines

References:	60.334(h)(3)

Abstract:

Q: Does EPA approve Alyeska Pipeline Service Company's fuel gas demonstration for fuel gas combusted at the Trans Alaska Pipeline System (TAPS) pump stations 1 through 4?

A: Yes. Based on the information submitted to EPA, Alyeska Pipeline Service Company has demonstrated that the fuel gas combusted at TAPS meets the definition of a natural gas as defined by 40 CFR 60.331(u).

Letter:

Reply To
Attn Of: AWT-107

CERTIFIED MAIL RECEIPT RETURN REQUESTED

John Baldridge
Pipeline Manager
Alyeska Pipeline Service Corporation
PO Box 60469
Fairbanks Alaska, 99706

Re: Trans Alaska Pipeline System Pump Stations 1 through 4, Natural Gas Demonstration,New Source Performance Standards Subpart GG, Standards of Performance for Stationary Gas Turbines

Dear Mr. Baldridge:

The United States Environmental Protection Agency (EPA) has reviewed Alyeska Pipeline Service Company's (Alyeska) natural gas demonstration letter, dated February 23, 2006. This letter is in response to Alyeska's request for a review of their natural gas demonstration, pursuant to New Source Performance Standard (NSPS) Subpart GG, Sec. 60.334(h)(3). Alyeska's request pertains to the Trans Alaska Pipeline System (TAPS) Pumps Station (PS)-1 through PS-4.

Background

Alyeska is the operator of TAPS, which is owned by BP Pipelines (Alaska) Inc., ExxonMobil Pipeline Company, Phillips Alaska Transportation, Inc., Unocal Pipeline Company, and Williams Alaska Pipeline Company. PS-1, PS-2, PS-3, and PS-4 are crude oil pumping facilities. These pump stations support the transport of crude oil by TAPS, via a 149-mile pipeline that runs from Prudhoe Bay to PS-4. The fuel gas is provided by the Prudhoe Bay Central Gas facility (CGF) which is owned and operated by British Petroleum Explorations (Alaska) Inc. (BPXA).

Alyeska has several existing fuel gas turbines subject to NSPS Subpart GG at PS-1 through PS-4. In addition, Alyeska is installing four new combustion turbines at PS-1, PS-3, and PS-4, as part of Alyeska's Strategic Reconfiguration project. These new combustion turbines are expected to startup in the third quarter of 2006. Alyeska has identified the following new sources as applicable to NSPS Subpart GG:

PS-1: One Siemens Cyclone turbine, Model SGT-400. One Solar Taurus turbine, Model 60S.
PS-3: Two Siemens Cyclone turbines, Model SGT-400. PS-4: Two Siemens Cyclone turbines, Model SGT-400.

Alyeska has also requested in their February 23, 2006, letter, that EPA include existing NSPS Subpart GG sources at PS-1 and PS-2 as part of the fuel gas demonstration.

PS-11: Solar Turbine Gas Compressors, tag number 31-C-10-1802T (source ID 6). Solar Turbine Gas Compressors, tag number 31-C-10-1803T (source ID 7). PS-22: Rolls Royce Avon Gas Generator, tag number 32-P-2AT (source ID 1). Rolls Royce Avon Gas Generator, tag number 32-P-2ET (source ID 2). Solar Turbine Electric Generator, tag number 32-G-29 (source ID 5).

All two turbines at PS-1 are fuel gas fired. Both Rolls Royce Avon Gas Generators at PS-2 are fuel gas fired, while the Solar Turbine Electric Generator at PS-2 is fuel gas and distillate oil fired.

NSPS Applicability and Regulatory Requirements

NSPS Subpart GG is applicable to stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour which commence construction, modification, or reconstruction after October 1977. 40 CFR Sec. 60.332 establishes standards for nitrogen oxides, while 40 CFR Sec. 60.333 establishes standards for sulfur dioxide. Pursuant to 40 CFR Sec. 60.334(h)(3), the owner or operator may elect not to monitor the total sulfur content of gaseous fuel combusted in a turbine, if that gaseous fuel is demonstrated to meet the definition of natural gas in 40 CFR Sec. 60.331(u) regardless if an existing EPA approved NSPS Subpart GG custom fuel motioning schedule3 (CFMS) requires such monitoring. To qualify as natural gas as defined under 40 CFR Sec. 60.331(u) fuel gas must contain no more than 20.0 grains per 100 scf (or equivalent 680 ppmw or 338 ppmv) of total sulfur. In addition, the fuel gas must either be composed of at least 70 percent methane by volume or have a gross caloric heating value between 950 and 1100 btu per scf.

Prudhoe Bay Central Gas Facility Fuel Gas Sulfur Content

Pursuant to 40 CFR Sec. 60.334(h)(3), owner or operators can use one of two methods to make the required fuel gas demonstration. Owners and operators can use the gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for gaseous fuel, specifying that the maximum total sulfur content is 20.0 grains per 100 scf or less. A representative fuel sample showing that the sulfur content of the gaseous fuel does not exceed 20.0 grains per 100 scf is also acceptable. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D of Part 75 is required.

Section 2.3.2.4(a)(2) of Appendix D requires either historic sampling data for the previous 12 months documenting total sulfur content of the fuel and/or percent by volume of methane. Alyeska provided EPA with the gas supplier's (BPXA) CGF fuel gas hydrogen sulfide (H_2S) monitoring data for the period from January 2003 through January 2006. The sampling was conducted using ASTM D4810-88 (length-of-stain tube test) which incorporated the Gas Producers Association Standard 2377-86. The use of ASTM D4810-88 as an alternative test method was approved by EPA in October 2, 1997, in a letter from EPA Region 10 to ARCO Alaska, Inc., the previous owner and operator of the CGF.

EPA has thoroughly reviewed the H2S monitoring data for the period from January 2003 through January 2006, provided in Attachment 1 of Alyeska's letter dated February 23, 2006. This data demonstrates that the CGF fuel gas sulfur level has been below the NSPS Subpart GG standard of 8000 ppmw. More important, this data demonstrates that the CGF fuel gas H2S content is consistent, ranging between 20 ppmv and 30 ppmv, with a standard deviation of 2.52. NSPS Subpart GG Sec. 60.331(u) states that natural gas contains 338 ppmv or less, at 20 degrees Celsius total sulfur.

Prudhoe Bay Central Gas Facility Fuel Gas Composition

40 CFR Sec. 60.331(u) stated that in addition to containing 338 ppmv at 20 degrees Celsius total sulfur, natural gas must either be composed of at least 70 percent methane by volume. Attachment 2 of Alyeska's February 23, 2006, letter provides the CGF?s fuel gas composition, between the periods of December 2003 to January 2006. This data demonstrates that the methane content of the CGF's fuel gas is greater than 70 percent by volume. The volumetric content of methane in the fuel gas supplied to PS-1 through PS-4 is approximately 80 percent by volume, +/- 1.2 percent. Based on EPA's review of the information provided by Alyeska in Attachments 1 and 2, Alyeska has adequately demonstrated that total sulfur and methane content of BPXA's CGF fuel gas meets the definition of natural gas found in 40 CFR Sec. 60.331(u). Therefore, EPA agrees with Alyeska's demonstration, that the fuel gas used at PS-1 through PS-4 meets the definition of natural gas.

This determination does not alter any of the other requirements of NSPS Subparts A and GG that may apply to Alyeska's PS-1, PS-2, PS-3 or PS-4. If you have any questions regarding this determination, please contact Natasha Greaves of my staff at (206) 553-7079.

Sincerely,

Jeff KenKnight, Manager
Federal & Delegated Air Programs Unit

PDF cc: Don Mark Anthony, Alyeska
James Baumgartner, ADEC Juneau
Moses Coss, ADEC Fairbanks
Cynthia Espinoza, ADEC ? Anchorage
John Pavitt, EPA ? Alaska

1 The Alaska Department of Conservation (ADEC) Air Quality Operating Permit No. 072TVP01 for PS-1, effective on January 1, 2003. 2 The ADEC Air Quality Operating Permit No. 073TVP01 for PS-2, effective on November 1, 2003. 3 EPA has approved a CFMS for Alyeska PS-1 and PS-2. PS-1's CFMS is dated October 30, 1997 and PS-2's CFMS is dated February 17, 1993.

Appendix F Permits

Application for Renewal of an Air Quality Operating Permit

Pump Station 4

Alyeska Pipeline Service Company

SLR Project No.: 105.021406.00001

July 25, 2025

F.1 Permit No. AQ0075CPT01

DEPARTMENT OF ENVIRONMENTAL CONSERVATION

AIR QUALITY CONSTRUCTION PERMIT

Permit No. 075CP01 March 11, 2003
Application Number X-146

The Department of Environmental Conservation (the department), under the authority of AS 46.14 and 18 AAC 50, issues a construction permit to the permittee, Alyeska Pipeline Service Company for permit revisions and increased fuel gas hydrogen sulfide content at Trans Alaska Pipeline System (TAPS) Pump Station 4.

This permit satisfies the obligation of the owner and operator to obtain a construction permit as set out in AS 46.14.130(a).

As required by AS 46.14.120(c), the permittee shall comply with the terms and conditions of this construction permit.

As set out in 18 AAC 50.340(i), this construction permit revises terms and conditions of Air Quality Control Permit to Operate No. 9572-AA009, issued March 4, 1996, last amended December 4, 1998.

[18 AAC 50.320(b), 1/18/97]

John F. Kuterbach, Manager
Air Permits Program

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Table of Contents

List of Abbreviations Used in this Permit

AAC	Alaska Administrative Code
ADEC	Alaska Department of Environmental Conservation
AS	Alaska Statutes
ASTM	American Society of Testing and Materials
CEMS	Continuous Emission Monitoring System
C.F.R.	Code of Federal Regulations
CO	Carbon Monoxide
COMS	Continuous Opacity Monitoring System
dscf	Dry standard cubic feet
EPA	US Environmental Protection Agency
gr/dscf	grain per dry standard cubic feet (1 pound = 7000 grains)
GPH	gallons per hour
HAPS	Hazardous Air Pollutants [hazardous air contaminants as defined in AS 46.14.990(14)]
H_2S	Hydrogen Sulfide
HHV	Higher heating value
ID	Source Identification Number
kW	kilowatts
MACT	Maximum Achievable Control Technology
Mlb	thousand pounds
MMBtu	Million British Thermal Units
NAICS	North American Industry Classification System
NESHAPs	Federal National Emission Standards for Hazardous Air Pollutants [as defined in 40 CFR 61]
NSPS	Federal New Source Performance Standards [as defined in 40 CFR 60]
NO_X	Oxides of Nitrogen
ppm	Parts per million
ppmv	Parts per million volume
PS	Performance specification
PSD	Prevention of Significant Deterioration
RM	Reference Method
SIC	Standard Industrial Classification
SO_2	Sulfur dioxide
TPH	Tons per hour
TPY	Tons per year
VOC	volatile organic compound [as defined in 18 AAC 50.990(103)]
Wt%	weight percent

Section 1 Identification

Names and Addresses

Permittee:	Alyeska Pipeline Service Company 1835 South Bragaw St. Anchorage, Alaska 99512
Facility:	Pump Station 4
Location:	Sections 5,8 T12S, R12E, Umiat Meridian
Physical Address:	155 Miles South of Prudhoe Bay, Alaska
Owner:	Owners of the Trans Alaska Pipeline System
Operator:	Alyeska Pipeline Service Company 1835 South Bragaw St. Anchorage, Alaska 99512
Permittee's Responsible Official	Jim F. Johnson. Or successor Pipeline Manager
Designated Agent:	CT Corporation System, Supervisor of Process/SP 801 West 10th St., Suite 300 Juneau, Alaska 99801
Facility and Building Contact:	PS 3 Operations and Maintenance Supervisor (907) 787-4305
Permitting Contact:	Don Mark Anthony P.O. Box 60469 Fairbanks, Alaska 99706 (907) 450-7652
Fee Contact:	Tammy Martin Environment Billing Administrator P.O. Box 40469 Fairbanks, Alaska 99706 (907) 450-5535

SIC Code of the Facility: 4612 – Crude petroleum pipelines.
NAICS Code: 486110 – Pipeline transportation of crude oil.

[18 AAC 50.320(a), 1/18/97]

Section 2 Emission Information and Classification

Emissions of Regulated Air Contaminants, as provided in permittee's application:

Oxides of Nitrogen (NO_X), Sulfur Dioxide (SO_2), Carbon Monoxide (CO), Particulate Matter, and Volatile Organic Compounds (VOC).

Construction Permit Classifications:

Note: Facility Classifications are described under 18 AAC 50.300(b) through (g), modification classifications are described under 18 AAC 50.300(h), and owner requested limits are described under 305(a)(1) through (4).

The permit revisions and increased fuel gas hydrogen sulfide content require a construction permit because:

a. The facility is classified as a Prevention of Significant Deterioration (PSD) Major Facility under 18 AAC 50.300(c)(1), as the facility has a potential to emit more than 250 tons per year of NO_X and CO, and

b. The permittee has requested under 18 AAC 50.305(a)(3), conditions that revise or rescind terms or conditions of a prior construction permit or permit issued under former 18 AAC 50.400.

[18 AAC 50.320(a)(2), 1/18/97]

Section 3 Permit Continuity

1. Except as revised or rescinded herein or as superseded by an Air Quality Permit issued under AS 46.14.170, the permittee shall comply with terms and conditions of Air Quality Control Permit to Operate No.9572-AA009 last amended December 4, 1998.

2. Terms and Conditions of Permit No.9572-AA009 are revised as follows:

2.1 Condition 16 is revised as follows

Permittee shall submit the results of the test, in the format set out in "Source Test Report Outline" (STRO), Volume III, Section IV.3, of the State Air Quality Control Plan, adopted by reference in 18 AAC 50.030, ~~(18 AAC 50.620)~~ to the department's Fairbanks Air Permit Office, ~~Air Quality Maintenance Section~~, 610 University Avenue, Fairbanks, Alaska 99709-3643, within 60 ~~forty-five (45)~~ days following completion of the set of tests.

2.2 Condition 17 is revised as follows

~~Process monitors as described by Exhibit C, shall be installed, operated, and maintained in accordance with 18 AAC 50.520.~~ Permittee shall install, use, and maintain the process monitors described in Exhibit C, "Process Monitoring Requirements." Permittee shall record the daily fuel consumption in each Avon gas generator, and the average daily speed, in RPM, of each Avon gas generator.

2.3 Condition 18 is revised as follows

~~Permittee shall conduct a quarterly test of the fuel gas to determine the sulfur (H_2S) content of the gas burned at the facility and the lower heating value of the fuel gas~~ The permittee or fuel supplier shall conduct a quarterly test, and on a change in the supply of fuel gas, and keep records of the test, to determine the sulfur (H_2S) content of the fuel gas burned at the facility as described in Exhibit C of this permit.

2.4 The terms of Conditions 20 and 21 are rescinded and replaced by the terms of Condition 7, "Air Pollution Prohibited," Condition 8, "Monitoring, Recordkeeping and Reporting for Air Pollution Prohibited," and Condition 9, "Excess Emission and Permit Deviation Reports" of **Permit No. 075CP01**.

2.5 Exhibit B, Section G: "Fuel Quality," is revised as follows.

~~Natural~~ Fuel Gas — not to exceed 36 ~~17~~ ppmv of hydrogen sulfide

2.6 Exhibit C "Monitored Source—Installation and Reporting Requirements," is revised as follows.

Fuel Gas — Determine the hydrogen sulfide content of the natural gas burned as fuel at least once per, quarter and on a change in the supply of fuel gas. A representative gas sample can be taken anywhere along the fuel gas line. Acceptable methods for H_2S are ASTM D-4810-88, ASTM D-4913-89, and Gas Producers Association (GPA) method 2377-86 or a portable H_2S analyzer. The permittee may propose to the department an alternative monitoring plan. The alternative monitoring plan must satisfy the underlying purpose for this monitoring and 18 AAC 50.350(g) and (h). ~~or upon a change in source of supply.~~ Acceptable methods are ASTM D 4810-88, ASTM 4913-89, ASTM D-4929, and Gas Producers Association (GPA) method 2377-86 or a portable H_2S analyzer. Determine the Lower Heating Value using a ~~calculational~~ method, based on the quarterly fuel gas composition analysis.

2.7 Exhibit D, 4, “Fuel Quality,” is revised as follows.

4. Fuel Quality: Report the concentration of H_2S in ppm and the Lower Heating value for the natural gas for the quarter. Include in the facility operating report a list of the H_2S content analysis results obtained during the reporting period, and any excess emission reports submitted in accordance with Condition 23 for exceeding the permitted fuel gas H_2S limit in Exhibit B, Section G, “Fuel Quality.” Report the fuel gas H_2S concentration in (ppmv), of the fuel gas for the quarter and identify the analytical method. Report the liquid fuel sulfur content and indicate whether is was from a sample or based on the monthly analysis of the supplier.

2.8 The excess emission reporting procedures listed in Exhibit D, 5, “Excess Emissions,” and 6, “Signature” are rescinded and replaced by the terms of Condition 7, “Air Pollution Prohibited,” Condition 8, “Monitoring, Recordkeeping and Reporting for Air Pollution Prohibited,” Condition 9, “Excess Emission and Permit Deviation Reports” and Section 6, “ADEC Notification Form” of **Permit No. 075CP01**.

3. If permit terms and conditions listed in this permit conflict with those of Permit No.9572-AA009 the permittee shall comply with terms and conditions listed herein.

Section 4 Construction Permit Source Inventory

4. **Authorization.** The permittee is authorized to operate the facility in accordance with the construction permit application as may be currently applicable. This permit authorizes the permittee to increase the fuel gas hydrogen sulfide (H_2S) content from 17 ppmv to 36 ppmv at Pump Station 4.

The facility equipment inventory is listed in Permit No. 9572-AA009, issued March 4, 1996

Section 5 Standard Construction Permit Conditions

This section contains permit conditions for air quality construction permits adopted by reference in 18 AAC 50.346 (a) (1-3).

Standard Construction Permit Condition I--Emission Fees[1]

5. Assessable Emissions. The permittee shall pay to the department annual emission fees based on the facility's assessable emissions as determined by the department under 18 AAC 50.410. The assessable emission fee rate is set out in 18 AAC 50.410. The department will assess fees per ton of each air contaminant that the facility emits or has the potential to emit in quantities greater than 10 tons per year. The quantity for which fees will be assessed is the lesser of

5.1 the facility's assessable potential to emit of **1207.4** tpy; or

5.2 the facility's projected annual rate of emissions that will occur from July 1 to the following June 30, based upon actual annual emissions emitted during the most recent calendar year or another 12 month period approved in writing by the department, when demonstrated by

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.

[18 AAC 50.346(a)(1)] 8/15/02

6. Assessable Emissions Estimates. Emission fees will be assessed as follows:

6.1 no later than March 31 of each year, the permittee may submit an estimate of the facility's assessable emissions to ADEC, Air Permits Program, ATTN: Assessable Emissions Estimate, 410 Willoughby Ave., Juneau, AK 99801-1795; the submittal must include all of the assumptions and calculations used to estimate the assessable emissions in sufficient detail so the department can verify the estimates; or

6.2 if no estimate is received 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 5.1.

[18 AAC 50.346(a)(1)] 8/15/02

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[1] Standard Permit Condition II has been modified from its original version. It has been modified to allow Alyeska to assess emissions from sources classified under 18 AAC 50.335 (q) through (v) under a one-time gross emission estimate.

6.3 The estimate of assessable emissions provided under paragraph 6.1 above may include a gross estimate of emissions for any insignificant sources defined under 18 AAC 50.335(q) through (v) located at the facility. Documentation is not required for subsequent submittals unless requested by the department.

[18 AAC 50.346(a)(1), 5/3/02 and 18 AAC 50.350(c) & 50.400 – 50.420, 1/18/97]

Standard Permit Condition II – Air Pollution Prohibited

7. 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. (18 AAC 50.110)

[18 AAC 50.346(a)(2)] 8/15/02

8. Monitoring, Record Keeping, and Reporting for Air Pollution Prohibited

8.1 If emissions present a potential threat to human health or safety, the permittee shall report any such emissions according to Condition 9, *"Excess Emissions and Permit Deviation Reports.*"

8.2 As soon as practicable after becoming aware of a complaint that is attributable to emissions from the facility, the permittee shall investigate the complaint to identify emissions that the permittee believes have caused or are causing a violation of Condition 7, *"Air Pollution Prohibited."*

8.3 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 an investigation because of a complaint or other reason, the permittee believes that emissions from the facility have caused or are causing a violation of Condition 7; or

b. the department notifies the permittee that it has found a violation of Condition 7.

8.4 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 7; and

d. any corrective actions taken or planned for complaints attributable to emissions from the facility.

8.5 With each facility operating report under Air Quality Control Permit to Operate No.9572-AA009, the permittee shall include a brief summary report 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.

8.6 The permittee shall notify the department of a complaint that is attributable to emissions from the facility within 24 hours after receiving the complaint, unless the permittee has initiated corrective action within 24 hours of receiving the complaint.

[18 AAC 50.346(a)(2)] 8/15/02

Standard Permit Condition III – Excess Emissions and Permit Deviation Reports[2]

9. Excess Emissions and Permit Deviation Reports.

9.1 Except as provided in Condition 8, "*Monitoring Record Keeping, and Reporting for Air Pollution Prohibited*," 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 commences 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 non-routine repair that causes emissions in excess of a technology based emission standard;

c. report all other excess emissions and permit deviations

[2] Standard Condition III has been modified from its original version. It has been modified to allow Alyeska to report an excess emission within 48 hours of discovering an excess emission rather than 48 hours of the excess emission occurring.

(i) within 30 days of the end of the month in which the emissions or deviation occurs or was discovered, except as provided in Conditions 9.1c(ii); and

(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 9.1c(i).

9.2 When reporting excess emissions, the permittee must report using either the department's online form, which can be found at www.dec.state.ak.us/awq/excess/report.asp, or, if the permittee prefers, the form contained in Section 6, ADEC Notification Form or the most recent version of the ADEC Notification Form available from the department. The permittee must provide all information called for by the form that is used.

9.3 When reporting a permit deviation, the permittee must report using the form contained in Section 6, ADEC Notification Form. The permittee must provide all information called for by the form.

9.4 If requested by the department, the permittee shall provide a more detailed written report as requested to follow up an excess emissions report.

[18 AAC 50.346(a)(3)]

Section 6 ADEC Notification Form

(Standard Permit Condition IV – Notification Form)

Fax this form to: (907) 269-7508 Telephone: (907) 269-8888

____
Company Name

____
Facility Name

Reason for notification:

❑ **Excess Emissions**
If you checked this box
Fill out section 1

❑ **Other Deviation from Permit Condition**
If you checked this box
fill out section 2

When did you discover the Excess Emissions or Other Deviation:

Date:__/__/__ Time:__:__

Section 1. Excess Emissions

(a) Event Information (Use 24-hour clock)**:**

	START Time**:** (hr:min):	**END** Time:	**Duration**
Date: ________	__________:__________	__________:__________	__________:__________
Date: ________	__________:__________	__________:__________	__________:__________
		Total:	__________:__________

(b) Cause of Event (Check all that apply)**:**

❑ START UP ❑ UPSET CONDITION ❑ CONTROL EQUIPMENT

❑ SHUT DOWN ❑ SCHEDULED MAINTENANCE ❑ OTHER ____________________

Attach a detailed description of what happened, including the parameters or operating Conditions exceeded.

(c) Sources Involved:

Identify each emission source involved in the event, using the same identification number and name as in the permit. List any control device or monitoring system affected by the event. Attach additional sheets as necessary.

Source ID No.	Source Name	Description	Control Device
________	________________	______________________________	________________
________	________________	______________________________	________________

(d) Emission Limit Potentially Exceeded

Identify each emission standard potentially exceeded during the event. Attach a list of ALL known or suspected injuries or health impacts. Identify what observation or data prompted this report. Attach additional sheets as necessary.

Permit Condition	Limit	Emissions Observed
______________________________	________________	______________________________
______________________________	________________	______________________________

(e) Excess Emission Reduction:

Attach a description of the measures taken to minimize and/or control emissions during the event.

(f) Corrective Actions:

Attach a description of corrective actions taken to restore the system to normal operation and to minimize or eliminate chances of a recurrence.

(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

Section 2. Other Permit Deviations

(a) Sources Involved:

Identify each emission source involved in the event, using the same identification number and name as in the permit. List any control device or monitoring system affected by the event. Attach additional sheets as necessary.

Source ID No.	Source Name	Description	Control Device
________	________________	______________________________	________________
________	________________	______________________________	________________
________	________________	______________________________	________________

(b) Permit Condition Deviation:

Identify each permit Condition deviation or potential deviation. Attach additional sheets as necessary.

Permit Condition	Potential Deviation
______________________________	______________________________
______________________________	______________________________
______________________________	______________________________

(c) Corrective Actions:

Attach a description of actions taken to correct the deviation or potential deviation and to prevent recurrence.

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:

Section 7 Permit Documentation

September 12, 2001	Letter from Don Mark Anthony (Alyeska) to Bill MacClarence (ADEC). Request for Revision or Revocation of Permit Terms: Taps Pump Station 4, Former 18 AAC 50.400 Permit No. 9572-AA009
January 23, 2002	Email from Don Mark Anthony (Alyeska) to Jim Baumgartner (ADEC). Request for reduced fuel gas H_2S sampling frequency.
February 13, 2002	Letter from Don Mark Anthony (Alyeska) to Jim Baumgartner (ADEC). Request to delete limit on NO_X emissions from the Avon gas turbines of 140 ppmv @15% O_2 ISO from Permit No. 9572-AA009.

F.2 Permit No. AQ0075CPT02

DEPARTMENT OF ENVIRONMENTAL CONSERVATION

AIR QUALITY CONTROL CONSTRUCTION PERMIT

Permit No.: AQ0075CPT02 **Date: Final – February 14, 2005**

The Department of Environmental Conservation (Department), under the authority of AS 46.03, AS 46.14, AS 46.40, 6 AAC 50, 18 AAC 15, and 18 AAC 50.315, issues an Air Quality Control Construction Permit to the Permittee listed below.

Operator and Permittee:	**Alyeska Pipeline Service Company** 900 E. Benson Blvd. Anchorage, AK 99508
Owner:	Owners of the Trans-Alaska Pipeline System
Stationary Source:	**Trans-Alaska Pipeline System Pump Station 4**
Location:	Latitude: 68° 25' 23" North; Longitude 149° 21' 18" West
Physical Address:	Sections 5 and 8, T12S, R12E Umiat Meridian
Permit Contact:	Don Mark Anthony (907) 450-7652

The Department authorizes the Permittee to install two turbines, two reciprocating internal combustion engines, and two boilers at Pump Station 4 as part of the **Strategic Recongifuration Project.**

This permit satisfies the obligation of the Permittee to obtain a construction permit as set out in AS 46.14.130. As required by AS 46.14.120, the Permittee shall comply with the terms and conditions of this construction permit.

This stationary source is classified under 18 AAC 50.300(b)(2) and 18 AAC 50.300(c)(1). The project is a modification classified under 18 AAC 50.300(h)(2).

John F. Kuterbach, Manager
Air Permits Program

Table of Contents

Abbreviations/Acronyms

AAC ....Alaska Administrative Code
ADEC............................Alaska Department of Environmental Conservation
APSC............................Alyeska Pipeline Service Company
AS.................................Alaska Statutes
ASTM...........................American Society of Testing and Materials
CEMS ....Continuous Emission Monitoring System
C.F.R. ....Code of Federal Regulations
DLE ....Dry Low Emissions
EPA ....Environmental Protection Agency
HHV ....Higher heating value
ISO ....International Standards Organization
LHV..............................Lower Heating Value
MACT ....Maximum Achievable Control Technology
mr&r ....monitoring, recordkeeping, and reporting
NA ....Not Applicable
NAICS ....North American Industry Classification System
NESHAPS ....National Emission Standards for Hazardous Air Pollutants
NSPS ....New Source Performance Standards
PS ....Performance specification
PS 4 ....Pump Station 4
PSD...............................Prevention of Significant Deterioration
RICE.............................Reciprocating Internal Combustion Engine
SIC................................Standard Industrial Classification
SN.................................Serial Number
TBD..............................To Be Determined

Units and Measures

bhp................................brake horsepower or boiler horsepower[1]
gr./dscf..........................grains per dry standard cubic feet (1 pound = 7,000 grains)
dscf ....dry standard cubic foot
gph................................gallons per hour
kW ....kiloWatts
kW-e ....kiloWatts electric[2]
mmBtu..........................million British Thermal Units
ppm...............................parts per million
ppmv.............................parts per million by volume
tph.................................tons per hour
tpy.................................tons per year
wt%...............................weight percent

Pollutants

CO ....Carbon Monoxide
HAPS............................Hazardous Air Pollutants
H_2S ....Hydrogen Sulfide
NO_X ....Oxides of Nitrogen
NO_2...............................Nitrogen Dioxide
NO ....Nitric Oxide
PM-10...........................Particulate Matter with an aerodynamic diameter less than 10 microns
SO_2 ....Sulfur Dioxide
VOC ....Volatile Organic Compound

[1] For boilers: One boiler horsepower is equal to 33,472 Btu per hour divided by the boiler's efficiency. For reciprocating internal combustion engines: one brake horsepower is equal to approximately 7,000 Btu per hour.
[2] kW-e refers to rated generator electrical output rather than engine output

Section 1 Permit Terms and Conditions

Emission Unit Inventory and Description

1. **Authorization.** The Permittee may install the emission units listed in Table 1, or replacement units as described in condition 1.1, at this stationary source in accordance with the terms and condition of this permit and the original construction permit application and subsequent submittals listed in Section 2. The Permittee shall configure Emission Units 12 and 13 with Dry Low Emissions (DLE) Technology.

Table 1 - Construction Permit Emission Unit Inventory[a]

No.	Type	Make/Model	Fuel	Rating/Size
12	Combustion Turbine Generator with DLE	Siemens Cyclone	Natural Gas/Diesel	12.9 MW ISO
13	Combustion Turbine Generator DLE	Siemens Cyclone	Natural Gas	12.9 MW ISO
14	Reciprocating Internal Combustion Engine	Caterpillar 3516B	Diesel	2,250 kW
15	Reciprocating Internal Combustion Engine	To Be Determined (TBD)	Diesel	65 kW-e
16	Boiler	TBD	Natural Gas	5 mmBtu/hr
17	Boiler	TBD	Natural Gas	5 mmBtu/hr

Table Notes:
[a] Except as noted elsewhere in this permit, the information in this table is for identification purposes only.

1.1 If the Permittee elects to install a replacement of a unit listed in Table 1, then at least 30 days before installation of the replacement unit, submit to the Department's Fairbanks office a demonstration that the maximum emission rates of NO_X, CO, PM-10, and VOC for the replacement unit are equal to or less than those from the unit it is replacing.

1.2 At least five days before initial startup[3] of Emission Units 12 through 17 or replacement units, submit the following to the Department's Fairbanks office:

a. vendor specification sheets that identify the unit type, make and model (including model number), serial number, and rating/size; and

b. the installation date and estimated date of startup.

[3] *Initial Startup* means when the emission unit is first fired.

1.3 Unless an extension is granted by the Department in writing as indicated in condition 1.4, decommission[4] existing Emission Units 1 through 9 listed in Table 1 of initial Operating Permit No. 075TVP01 within 270 calendar days after actual initial startup of any Emission Unit 12 through 17 or replacement unit.

1.4 The Department may allow an extension of the "startup period" for due cause. Submit a request for an extension in writing to the Department's Fairbanks office within 240 days of initial startup of any Emission Unit 12 through 17 or replacement unit. Include a description of the reason for the extension. The Department will grant an extension of up to 90 days if the Department finds due cause exists.

1.5 Include with the next operating report described in condition 45 of initial Operating Permit No. 075TVP01:

a. the actual initial startup dates for each Emission Unit 12 through 17 or replacement units;

b. the decommissioning dates for each Emission Unit 1 through 9; and

c. copies of the notifications and records required by conditions 1.1, and 1.2.

Ambient Air Quality Protection Requirements

2. Operational Limits (NO_X, SO_2). The Permittee shall restrict 12 consecutive month total operating hours of Emission Units 12, 14 and 15 to less than the limit listed in Table 2 to protect ambient air quality.

Table 2 – Operating Hour Limits[a]

Emission Unit No.	12-Consecutive Month Hourly Limit, in hours
12	240 on diesel fuel
14	600 total
15	300 total

2.1 Monitor and record hours that Unit 12 operated on diesel fuel and total hours of operation for Units 14 and 15 for each month.

2.2 By the last day each month, add previous months total to the preceding 11 months to get 12 consecutive month total.

2.3 Report as described in condition 43 of initial Operating Permit No. 075TVP01 if any 12 month total exceeds a limit in Table 2.

[4] *Decommission* means the fuel systems and generator electrical leads have been disconnected.

2.4 Include copies of records required under conditions 2.1 and 2.2 with the operating report for that period required described in condition 45 of initial Operating Permit No. 075TVP01.

3. **Fuel Sulfur.** The Permittee shall comply with SO_2 ambient air quality standards and increments as follows.

3.1 Limit the hydrogen sulfide (H_2S) content of fuel gas to no greater than 150 parts per million by volume (ppmv). Monitor according to condition 6.1a of initial Operating Permit No. 075TVP01, and report as described in condition 43 of initial Operating Permit No. 075TVP01 any time the fuel gas H_2S content exceeds 150 ppmv.

3.2 Limit the diesel fuel sulfur content to no greater than 0.20 percent by weight. Monitor according to condition 6.2a of initial Operating Permit No. 075TVP01, and report as described in condition 43 of initial Operating Permit No. 075TVP01 any time the diesel fuel sulfur content exceeds 0.2 percent by weight.

4. **Stack Parameters.** The Permittee shall install and maintain the exhaust stack for Emission Unit 12 to at least 51 feet above gravel pad elevation.

Owner Requested Limits to Avoid Project Classification as a PSD-Major Modification

5. **Carbon Monoxide (CO) Limit.** For Units 12 and 13, the Permittee shall

a. comply with operating hour limits listed in Table 2;

b. until site-specific emission rates have been determined in accordance with condition 6.6 and site-specific operating limits in accordance with condition 6.6d, use the following limits that are based on vendor data:

(i) limit operating hours (including diesel operating hours) at less than or equal to 50 percent load ($H_{\leq 50}$) to no more than 2,160 hours per 12 consecutive months; and

(ii) limit operating hours (including diesel operating hours) at loads greater than 50 percent and less than or equal to 60 percent ($H_{50\text{-}60}$) as defined in Equation 1:

Equation 1 $$H_{50-60} = 10{,}177 - 3.9177(H_{\langle or = 50})$$ [5]

Where: $H_{\leq 50}$ = number of hours at less than or equal to 50 percent load (maximum 2,160);

$H_{50\text{-}60}$ = number of hours at loads greater than 50 percent and less than or equal to 60 percent;

[5] From page 2-28 of the PS 4 application dated August 2004. APSC developed this equation based on vendor data, as described in Attachment E of the TAR.

c. after site-specific emission rates have been determined in accordance with condition 6.6a and 6.6b, use the revised the operating hour limits developed in accordance with condition 6.6d, except as indicated in 6.6c.

d. ensure the **hourly average**[6] minimum intake temperature is above minus 20 degrees Fahrenheit.

5.1 For Units 12 and 13 separately, record the **hourly average** turbine intake temperature (*T*) in degrees Fahrenheit, for fuel gas and diesel fuel.

5.2 For Units 12 and 13 separately, using an hour meter, monitor and record the number of hours operated (including diesel operating hours) at less than or equal to 50 percent load; and at greater than 50 percent but less than or equal to 60 percent load, calculated as follows:

a. Measure and record the **hourly average** power output in kW;

b. Based on *T* recorded in condition 5.1, calculate the maximum turbine load in kW for that hourly temperature as follows:[7]

(i) If *T* is less than or equal to minus 20 degrees Fahrenheit:

$$L_{MAX} = 12{,}958$$

(ii) If *T* is between minus 20 degrees Fahrenheit and plus 20 degrees Fahrenheit:

$$L_{MAX} = 13{,}292 + 10.706T - 0.3105T^2$$

(iii) If *T* is above plus 20 degrees Fahrenheit:

$$L_{MAX} = 14{,}548 - 55.97T$$

Where: L_{MAX} = Maximum turbine load in kW
T = Hourly temperature in degrees Fahrenheit

c. Calculate the hourly percent load by dividing the actual power output in kW recorded in condition 5.2a by the maximum load calculated in condition 5.2b.

5.3 Sample fuel gas heat content quarterly and measure the heat content (in mmBtu/lbm) using a method using ASTM 3588 or other method approved by the department.

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6 For the purposes of this permit, hourly average shall be calculated using a minimum of one data point every 15 minutes, excluding periods of startup not to exceed 10 minutes.

7 Email from Don Mark Anthony, February 11, 2005.

5.4 No later than the last day of each month, calculate the number of hours in each tier for the previous month and add to the preceding 11 months to get the 12 month total.

5.5 Report as excess emissions as described in condition 43 of initial Operating Permit 075TVP01 any time the

a. cumulative operating hours (including diesel operating hours) for Units 12 and 13 exceed the limits in this condition; and

b. **hourly average** turbine intake temperature is below the limit in this condition.

5.6 Report as described in condition 47 of initial Operating Permit No. 075TVP01

a. the monthly and 12 consecutive month total operating hours at

(i) less than or equal to 50 percent load (Tier 1); and

(ii) greater than 50 percent load and less than or equal to 60 percent load (Tier 2).

b. the quarterly fuel heat content (LHV); and

c. minimum **hourly average** turbine intake temperature.

6. CO Emissions Source Tests. Within 365 days of startup of the first of Emission Unit 12 or 13, the Permittee shall conduct one CO and oxygen source test in June, July, or August (to represent summertime) and one CO and oxygen source test in December, January, or February (to represent wintertime) source test burning natural gas fuel in accordance with Section 9 of initial Operating Permit No. 075TVP01 and as follows:

6.1 The wintertime source test shall be at less than 0 degrees Fahrenheit.

6.2 Test either Emission Unit 12 or 13, in the following three load ranges (adjusted for maximum load at different temperatures as indicated in condition 5.2b):

a. Less than or equal to 60 percent (to represent Tier 1);

b. Less than or equal to 50 percent (to represent Tier 2); and

c. Less than or equal to 25 percent (to represent Tier 3).

6.3 During each run, monitor and record the unit's electric load, turbine inlet temperature, and fuel consumption (using a fuel meter accurate to within two percent of full scale) no less than once every 15 minutes.

6.4 Obtain for the fuel used during the testing, the fuel specific LHV or calculate the LHV for a representative sample of the fuel in accordance with ASTM D 3588.

6.5 For each load range, determine the load specific CO emission concentration in ppmv using Method 19, assuming 15 percent oxygen.

6.6 Table 3 shows the emission concentrations used to develop the operating hour limits in condition 5.b, based on vendor data. After both the summer and winter tests required under this condition, and except as indicated in condition 6.8, replace the operating hour limits in condition 5.b with site specific operating hour limits developed as follows:

a. Adjust all **wintertime** emission concentrations shown in Table 3 for each load range (Tier 1, 2, and 3) separately. Increase by the highest percent increase or decrease by the lowest percent decrease for that load range during the wintertime test using lineal interpolation, except as indicated in condition 6.6c.

b. Adjust all **summertime** emission factors shown in Table 3 for each load range (Tier 1, 2, and 3) separately. Increase by the highest percent increase or decrease by the lowest percent decrease for that load range during the summertime test using lineal interpolation, except as indicated in condition 6.6c.

c. The Permittee may elect not to adjust an emission concentration for which source test results are lower than those assumed in the development of condition 5.b (as indicated in Table 3).

Table 3 - CO Emission Rates for Emission Units 12 and 13 Burning Fuel Gas (ppmvd) and corrected to 15 percent Oxygen, Based on Vendor Data[a]

Sourc e Test Average Load (Percent)[b]	Source Test Turbine Inlet Temperature, T, degrees Fahrenheit								
	T≥90	80≤T<90	60≤T<80	40≤T<60	20≤T<40	0≤T<20	Minus 10≤T<0	Minus 20≤T<Minus 10	T≤Minus 20
	Summertime				Wintertime				
Load≥60 (Tier 1)	60	60	60	60	60	60	60	60	60
60>Load≥50 (Tier 2)	30	30	60	60	575	575	1,450	1,562	1,562
≤50 (Tier 3)	1,800,	2,200	2,500	2,590	3,750	3,750	5,000	5,625	5,625

Table Notes:
[a] Emission rates in ppmvd are the emission rates used to develop the equations in condition 5.b, as described in the application.
[b] Take into account the change in maximum load with temperature.

d. Except as described in condition 6.7, and using Table 4 as a guide, calculate a linear equation that represents the maximum number of hours that the turbines can operate in Tier 3 and Tier 2 operating modes, while keeping the estimated emissions below 1041 tons of CO per year as follows:[8]

(i) Fill in CO emission rates in ppmv from source tests as described in condition 6.6a and 6.6b.

(ii) Initially assign 0 hours of operation in Tier 3 and allocate remaining hours to Tier 1, then gradually shift hours to Tier 2 until total CO emissions equal 1,041 tpy. Including both turbines in the calculations, calculate CO emissions for each month using Equation 2 and Equation 3.

Equation 2 $E = X(0.002485)$ [9]

Where:	E	=	CO emissions in lb per mmBtu, based on LHV of fuel fired
	X	=	CO in ppmv, corrected to 15 percent oxygen

Equation 3 $CO = (E)(HC)(H)\left(1ton/2000lb\right)$

Where:	CO	=	CO emissions in tons per month
	E	=	CO emissions in lb per mmBtu, based on LHV of the fuel fired
	HC	=	Heat consumption rate at a given temperature and load (already calculated as described in Step 2 of Appendix E of the TAR and shown in Table 4 for average monthly ambient temperatures at PS 4)
	H	=	operating hours

(iii) Repeat previous step for 2,160 hours in Tier 3 (allocate to the worst case CO emission rates first).

(iv) Replace the limits in condition 5.b based on the linear equation.

6.7 Obtain department approval in writing to use another method to calculate allowable operating hours in each Tier.

6.8 If source test emissions concentrations for all load ranges, for both summer and winter tests, are lower than shown in Table 3, APSC may elect not to revise the emission limits listed in condition 5.b.

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8 This condition describes the method used by APSC to define the initial correlation.

9 Equation 2 is based on Method 19, assuming 15 percent oxygen, and an F_d of 9,652 dscf per mmBtu for fuel gas as provided in application supplement dated January 12, 2005. The equation includes a conversion factor for converting ppmv to lb per scf (lb per scf is equal to ppmvd multiplied by 7.267 E^{-8}). See Attachment E of the TAR.

6.9 Submit information collected in conditions 6.2 through 6.6, including the methodology used to calculate heat input during the source test, in each source test report as described by Section 9 (General Source Testing and Monitoring Requirements) of initial Operating Permit No. 075TVP01.

Table 4 – Calculation of Operating Hour Limits

		Loads Greater than or Equal to 60% (Tier 1)				Loads Greater than or Equal to 50% and Less than 60% (Tier 2)				Loads Greater than 0% and Less than 50% (Tier 3)			
Mo	Amb. Temp	Days	HC (mmBtu/hr)	CO (ppmv)	CO (tons)	Days	HC (mmBtu/hr)	CO (ppmv)	CO (tons)	Days	HC (mmBtu/hr)	CO (ppmv)	CO (tons)
Jan (31)	-17		85.1				75.2				52.6		
Feb (28)	-16		85.2				75.3				52.7		
Mar(31)	-7		86.2				76.2				53.3		
Apr (30)	10		87.4				77.3				54.1		
May (31)	30		85.6				80.9				53.6		
Jun (30)	49		81.4				76.9				51.8		
Jul(31)	55		80.1				75.8				51.3		
Aug (31)	49		81.5				77.0				51.9		
Sep (30)	37		84.2				79.6				53.0		
Oct (31)	17		87.7				77.5				54.3		
Nov (30)	0		86.8				76.7				53.7		
Dec (31)	-14		85.4				75.5				52.8		
Total CO													

7. **Limits to Prevent Project Classification as a PSD Major Modification for NO_X.** The Permittee shall comply with operating hour limits for Units 18, 20 and 21 listed in Table 2. Calculate and record the 12 consecutive month total operating hours for Emission Unit 18 burning diesel using data obtained in condition 5.1.

8. **Limits to Prevent Project Classification as a PSD Major Modification for NO_X.** The Permittee shall comply with operating hour limits for Units 12, 14 and 15 listed in Table 2. Calculate and record the 12 consecutive month total operating hours for Emission Unit 12 burning diesel using data obtained in condition 5.1.

9. **Limits to Prevent Project Classification as a PSD Major Modification for SO_2.** The Permittee shall comply with operating hour limits for Units 12, 14 and 15 listed in Table 2, and fuel sulfur limits in condition 3.

Federal New Source Performance Standards (NSPS) Subpart A, General Provisions (Emission Units 12 and 13)

10. **Notification and Recordkeeping – 40 C.F.R 60.7(a)(1) and (a)(3).** The Permittee shall comply with 40 C.F.R. 60.7(a)(1), and (a)(3).

11. **Startup, Shutdown, & Malfunction Requirements – 40 C.F.R. 60.7(b).** The Permittee shall comply with 40 C.F.R. 60.7(b).

12. **Excess Emission and Monitoring Systems Performance Report – 40 C.F.R.60.7(c).** The Permittee shall comply with 40 C.F.R. 60.7(c)(1) through (4).

13. **Recordkeeping – 40 C.F.R. 60.7(f).** The Permittee shall comply with 40 C.F.R. 60.7(f).

14. **Performance Tests – 40 C.F.R. 60.8(a) – (f).** The Permittee shall comply with 40 C.F.R. 60.8(a) through (f).

15. **Good Air Pollution Practice – 40 C.F.R 60.11(d).** The Permittee shall comply with 40 C.F.R. 60.11(d).

16. **Credible Evidence – 40 C.F.R. 60.11(g).** The Permittee shall comply with 40 C.F.R. 60.11(g).

17. **Circumvention – 40 C.F.R. 60.12.** The Permittee shall comply with 40 C.F.R. 60.12.

18. **Monitoring – 40 C.F.R. 60.13(a), (b), (d), (f), (g), (i), and (j).** The Permittee shall comply with 40 C.F.R. 60.13(a), (b), (f), and (i), and if a CEMS is installed under 40 C.F.R. 60.334(e), shall also comply with 40 C.F.R. 60.13(d), (e), (g), and (j).

Federal New Source Performance Standards (NSPS) – Subpart GG, Standards of Performance for Stationary Gas Turbines (Emission Units 12 and 13)

19. **NO_X Standard - 40 C.F.R. 60.332.** On and after the date on which the performance test required by 40 C.F.R. 60.8 (condition 14) is completed, every owner or operator [Permittee] subject to the provisions of Subpart GG as specified in paragraphs (b), (c), and (d) of 40 C.F.R. 60.332 shall comply with the NO_X emission standard of

    19.1 212 ppmvd when firing fuel gas, except as provided in 40 C.F.R. 60.331(e), (f), (g), (h), (i), (j), (k), and (l); and

    19.2 205 ppmvd when firing diesel fuel, except as provided in 40 C.F.R. 60.331(e), (f), (g), (h), (i), (j), (k), and (l).

20. **SO_2 Standard - 40 C.F.R. 60.333.** On or after the date on which the performance test required to be conducted by 40 C.F.R. 60.8 [condition 14] is completed, every owner or operator [Permittee] subject to the provisions of Subpart GG shall comply with one or the other of the following conditions:

    20.1 **40. C.F.R. 60.333(a).** No owner or operator subject to the provisions of Subpart GG shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

    20.2 **40. C.F.R. 60.333(b).** No owner or operator subject to the provisions of Subpart GG shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight (8000 ppmw).

21. **Monitoring - 40 C.F.R. 60.334(e).** The owner or operator [Permittee] of any new turbine that commences construction after July 8, 2004, and which does not use water or steam injection to control NO_X emissions may elect to use a NO_X CEMS installed, certified, operated, maintained, and quality –assured as described in paragraph (b) of 40 C.F.R 60.334. An acceptable alternative to installing a CEMS is described in paragraph (f) of 40 C.F.R. 60.334 [condition 22].

22. **Monitoring - 40 C.F.R. 60.334(f).** The owner or operator [Permittee] of a new turbine who elects not to install a CEMS under paragraph (e) of 40 C.F.R. 60.334, may instead perform continuous parameter monitoring as described in 40 C.F.R. 60.334(f)(2).

23. **Monitoring - 40 C.F.R. 60.334(h).** The owner or operator [Permittee] of any stationary gas turbine subject to the provisions of Subpart GG:

23.1 **40 C.F.R. 60.334(h)(1).** Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) [condition 23.2] of 40 C.F.R. 60.334. The sulfur content of the fuel must be determined using total sulfur methods described in 40 C.F.R. 60.335(b)(10) [condition 27.7]. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084-82, 94, D5504-01, D6228-98, or Gas Processors Association Standard 2377-86 (all of which are incorporated by reference – see 40 C.F.R. 60.17), which measure the major sulfur compounds may be used.

23.2 **40 C.F.R. 60.334(h)(3).** Notwithstanding the provisions of paragraph (h)(1) of 40 C.F.R. 60.334 [condition 23.1], the owner or operator [Permittee] may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in 40 C.F.R. 60.331(u), regardless of whether an existing custom schedule approved by the administrator for Subpart GG requires such monitoring. The owner or operator [Permittee] shall use one of the following sources of information to make the required demonstration:

a. **40 C.F.R. 60.334(h)(3)(i).** The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20 grains/100 scf or less; or

b. **40 C.F.R. 60.334(h)(3)(ii).** Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of C.F.R. Title 40 is required.

24. Monitoring - 40 C.F.R. 60.334(i). The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

24.1 **40 C.F.R. 60.334(i)(1).** *Fuel Oil.* The Permittee shall comply with 40 C.F.R. 60.334(i)(1).

24.2 **40 C.F.R. 60.334(i)(2).** *Gaseous Fuel.* The Permittee shall comply with 40 C.F.R. 60.334(i)(2).

24.3 **40 C.F.R. 60.334(i)(3).** *Custom Schedules.* Notwithstanding the requirements of 40 C.F.R. 60.334(i)(2) [condition 24.2] operators [Permittees] or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (i)(3)(i) and (i)(3)(ii) of 40 C.F.R. 60.334 [conditions 24.3a and 24.3b] custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in 40 C.F.R. 60.333.

a. **40 C.F.R. 60.334(i)(3)(i).** The two custom sulfur monitoring schedules set forth in paragraphs (i)(3)(i)(A) through (D) (including (C)(1) through (3)) and in paragraph (i)(3)(ii) of 40 C.F.R. 60.334 [condition 24.3b] are acceptable without prior Administrator approval.

b. **40 C.F.R. 60.334(i)(3)(ii).** The owner or operator [Permittee] may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of C.F.R. Title 40 to determine a custom sulfur sampling schedule, as described in 40 C.F.R. 60.334(i)(3)(ii)(A) through (D).

25. **Monitoring - 40 C.F.R. 60.334(j).** For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under Subpart GG, the owner or operator [Permittee] shall submit reports of excess emissions and monitor downtime, in accordance with 40 C.F.R. 60.7(c) [condition 12]. Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under 40 C.F.R. 60.7(c) [condition 12], periods of excess emissions and monitor downtime that shall be reported are defined as follows:

25.1 *For nitrogen oxides* [for turbines required to monitor combustion parameters under 40 C.F.R. 60.334(f) - condition 22] in 40 C.F.R. 60.334(j)(1)(iv)(A) and (B).

25.2 *For sulfur dioxide* [for turbines required to monitor under 40 C.F.R. 60.334(h) - condition 23] in 40 C.F.R. 60.334(j)(2)(i) through (iii).

25.3 *For Ice Fog.* Each period during which an exemption provided in 40 C.F.R. 60.332(f) is in effect shall be reported as indicated in 40 C.F.R. 60.334(j)(3).

25.4 *For Emergency Fuel.* Each period during which an exemption provided in 40 C.F.R. 60.332(k) is in effect shall be reported as indicated in 40 C.F.R. 60.334(j)(4).

25.5 The Permittee shall submit reports required under 40 C.F.R. 60.7(c) [condition 12] in accordance with 40 C.F.R. 60.334(j)(5).

26. **40 C.F.R. 60.335(a).** The owner or operator (Permittee) shall conduct the performance tests required in 40 C.F.R. 60.8 (condition 14) using a method described in

26.1 40 C.F.R. 60.335(a)(1) through (4);

26.2 40 C.F.R. 60.335(a)(5)(i) and (ii); or

26.3 40 C.F.R. 60.335(a)(6).

27. 40 C.F.R. 60.335(b). The owner or operator [Permittee] shall determine compliance with the applicable nitrogen oxides emissions limitation in 40 C.F.R. 60.332 and shall meet the performance test requirements of 40 C.F.R. 60.8 [condition 14] as follows:

27.1 as indicated in 40 C.F.R. 60.335(b)(1);

27.2 as indicated in 40 C.F.R. 60.335(b)(2);

27.3 as indicated in 40 C.F.R. 60.335(b)(3);

27.4 as indicated in 40 C.F.R. 60.335(b)(6), [if using CEMS];

27.5 as indicated in 40 C.F.R. 60.335(b)(7), [if using CEMS];

27.6 as indicated in 40 C.F.R. 60.335(b)(8);

27.7 if the owner or operator is required under 40 C.F.R. 60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel as indicated in 40 C.F.R 60.334(b)(1)(i) and (ii);

27.8 as indicated in 40 C.F.R. 60.335(b)(11); and

27.9 as indicated in 40 C.F.R. 60.335(c).

State Emission Standards

28. Visible Emissions. The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from Emission Units 12 through 17 to reduce visibility through the exhaust effluent by any of the following:

a. more than 20 percent for a total of more than three minutes in any one hour;

b. more than 20 percent averaged over any six consecutive minutes.

28.1 For Emission Unit 13, 16, and 17 (gas-fired units), verify compliance with the visible emission standard by certifying annually in accordance with condition 46 of initial Operating Permit No. 075TVP01 whether the unit burned only fuel gas. Report as a permit deviation as described in condition 43 of initial Operating Permit No. 075TVP01 if other fuel was burned in the unit.

28.2 For each Emission Units 12, 14, and 15 (dual and liquid fuel fired units), comply as follows while using liquid fuel:

a. Verify initial compliance with the visible emission standard using either condition 28.2a(i) or 28.2a(ii).

(i) Prior to unit installation, obtain a certified manufacturer guarantee that each emission unit will comply with the visible emission standard and attach a copy of the guarantee to the next operating report described in condition 45 of initial Operating Permit No. 075TVP01.

(ii) Conduct a visible emission observation in accordance with Section 9 of initial Operating Permit No. 075TVP01 within 90 days after each unit is first fired on liquid fuel. Attach a copy of the Method 9 surveillance records to the next operating report described in condition 45 of initial Operating Permit No. 075TVP01.

b. For each unit that operates more than 400 hour per calendar year on liquid fuel, monitor, record, and report as described in Section 13 of initial Operating Permit No. 075TVP01.

29. Particulate Matter (PM). The Permittee shall not cause or allow PM emission from any Emission Unit 12 through 17 to exceed 0.05 grains per dry standard cubic foot (gr/dscf) of exhaust gas corrected to standard conditions and averaged over three hours.

29.1 For Emission Unit 13, 16, and 17, the Permittee shall comply with condition 28.1.

29.2 For Emission Units 12, 14, and 15, the Permittee shall comply with monitoring, recordkeeping, and reporting for liquid fuel-fired equipment as described in initial Operating Permit No. 075TVP01, condition 5 and Section 13.

30. Sulfur Compound Emissions. The Permittee shall not cause or allow sulfur compound emission, expressed as SO_2, from any Emission Unit 12 through 17 to exceed 500 ppm averaged over three hours. Monitor, record, and report as described in condition 6 of initial Operating Permit No. 075TVP01.

Section 2 Permit Documentation

August 16, 2004	Letter from Gregory T. Jones, APSC, to Jim Baumgartner, ADEC, with an application for an Air Quality Control Construction Permit.
November 10, 2004	Letter from Daniel T. Hisey, APSC, to Jeanette Brena, ADEC, TAPS Pump Station 4 Construction Permit Application Revision.
November 26, 2004	Email from Jeff Alger (RETEC) to Sally A. Ryan (ADEC) containing additional information.
January 12, 2005	Email from Jeff Alger (RETEC) o Sally A. Ryan (ADEC) containing additional information.
January 26, 2005	Letter from Gregory T. Jones to Bill Walker. Application Supplement containing the information submitted by email on November 26, 2004 and January 12, 12005 and certifying that the information is true, accurate, and complete.
February 11, 2005	Email from Don Mark Anthony to Sally Ryan, containing additional information.

F.3 Permit No. AQ0075CPT03

DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY CONTROL CONSTRUCTION PERMIT

Permit No.: AQ0075CPT03 **Final October 28, 2005**

The Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues an Air Quality Control Construction Permit to

Operator and Permittee:	**Alyeska Pipeline Service Company** 900 E. Benson Blvd. Anchorage, AK 99508
Owner:	Owners of the Trans Alaska Pipeline System
Stationary Source:	**Trans-Alaska Pipeline System (TAPS) Pump Station 4**
Location:	Latitude: 68° 25' 23" North; Longitude 149° 21' 18" West
Physical Address:	Sections 5 and 8, T12S, R12E Umiat Meridian
Physical Address:	Same as Location
Permit Contact:	Don Mark Anthony (907) 450-7652

The Department authorizes Alyeska Pipeline Service Company's requested emission limits to classify Pump Station 4 as Hazardous Air Pollutant synthetic minor.

As required by AS 46.14.120, the Permittee shall comply with the terms and conditions of this construction permit.

This stationary source is classified under 18 AAC 50.300(b)(2), 18 AAC 50.300(c)(1), 18 AAC 50.325(b)(2), and 18 AAC 50.325(c). This project is an owner requested limit as set out by 18 AAC 50.305(a)(4).

John F. Kuterbach, Manager
Air Permits Program

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List of Abbreviations Used in this Permit

AAC........................... Alaska Administrative Code
ADEC .... Alaska Department of Environmental Conservation
AS .... Alaska Statutes
ASTM .... American Society of Testing and Materials
bbl .... barrels
C.F.R.......................... Code of Federal Regulations
CO_2 .... Carbon dioxide
EPA............................. US Environmental Protection Agency
gal .... gallons
HAP .... Hazardous Air Pollutant
ID .... Source Identification Number
lb .... pounds
PS................................ Pump Station
TAPS .... Trans Alaska Pipeline System
tpy .... Tons per year
wt%............................ weight percent
yr .... Year

Section 1 Owner Requested Limits to Avoid Classification as a HAP Major

1. **Owner Requested Limits (ORLs).** To avoid classification as a Hazardous Air Pollutant (HAP) Major Stationary Source under 18 AAC 50.300(f), the Permittee shall limit the HAP emissions from the crude oil breakout tank (Tank 140), described in Table 1 of Operating Permit No. 075TVP01, to no more than 8.0 tons per 12 month rolling period for any individual HAP and 16.9 tons per 12 month rolling period for the aggregate total of HAPs.

2. **Monitoring.** The Permittee shall monitor compliance with Condition 1 as follows:

   2.1 Sample the discharge crude stream at Pump Station 1 as follows:

      a. for the first twelve months sample once every three calendar months;

      b. after four quarterly samples have been obtained, sample once every six calendar months;

      c. after four quarterly samples and two semi annual samples have been obtained, sample once every twelve calendar months.

      d. sampling under Conditions 2.1a, 2.1b and 2.1c is not required if the Permittee is satisfying the crude oil sampling requirements for HAP ORLs at another TAPS pump station.

   2.2 Determine the amounts of 1,3 butadiene, N-hexane, benzene, 2,2,4 trimethylpentane, toluene, ethyl benzene, xylenes, isopropyl benzene, and naphthalene in the crude oil. The Permittee shall use ASTM method D-5134M unless an equivalent method is approved by the Department.

   2.3 Monitor and record tank level changes at least once per hour. Monitor the total volume of crude oil routed to Tank 140 using tank level change indicators, or by another appropriate methodology approved by the Department. Calculate the monthly total volume of crude oil routed to Tank 140.

   2.4 For any period during which crude oil flow data is unavailable under Condition 2.3, the Permittee shall estimate the flow rate of crude oil to Tank 140 using a crude oil flow rate of 1,675,000 barrels per year (bbl/yr), prorated over the time period during which no data is available[1].

   2.5 Calculate the 12-month rolling total HAP emissions from Tank 140 for each month as follows:

---

[1] The pro-ration calculation for periods when no data is available do not apply to periods where the tank is drained and isolated.

a. Use the most recent crude composition analysis in Conditions 2.2 and the total volume of crude oil routed to the tank for the month determined from Conditions 2.3 or 2.4.

b. Use the methodology presented in the Permittee's October, 2003 permit application as described in Appendix A, or use a similar Department approved methodology.

c. Perform and record the calculations for the six calendar months at the time the semi-annual Operating Reports are due under Permit No. 075TVP01 for the six calendar months covered in the Operating Report.

d. If the most recent calculations under Condition 2.5c show HAP emissions exceed 50% of either limit under Condition 1, for any 12-month rolling period, perform and record the calculations for each calendar month no later than 30 days after the end of the month.

e. After performing six months of calculations under condition 2.5d and showing HAP emissions less than 50% of each limit in Condition 1, the Permittee shall perform calculations semi-annually at the time the Operating Reports are due.

2.6 If the calculated HAP emissions under Condition 2.5 exceed 90% of either of the limits in Condition 1,

a. Within 4 months of discovery, initiate and complete a validation demonstration of predicting crude vapor HAP content from crude oil sampling by comparing HAP emissions derived using Gas Producers Association Method 2286 or an appropriate vapor phase analytical method approved by the Department on the headspace of any one of the breakout tanks at Pump Stations 3, 4, 5, 7 or 9 to calculations based on sampling of Pump Station 1 crude discharge stream;

b. For headspace sampling, take four samples of the tank headspace, consecutively, and if possible take all on the same day; and

c. For crude oil sampling, take at least two crude oil discharge samples at Pump Station 1, within 15 days of headspace sampling;

d. Use the average results of the sampling conducted under Condition 2.6b and 2.6c, to compare the calculated HAP emissions using crude oil discharge analysis to those using the in-tank headspace analysis carried out concurrently.

(i) If the crude oil analysis methodology predicts higher emissions than the headspace sampling, sample the crude oil once every 12 calendar months and calculate the HAP emissions according to Condition 2.5;

(ii) If the crude oil analysis methodology predicts lower emissions than the headspace sampling, calculate HAP emissions by sampling at quarterly intervals and calculate according to Condition 2.5 and multiply all results by the ratio between test results from Conditions 2.6b and 2.6c. When HAP emissions fall below 90%, the Permittee may reduce sampling frequency to once every 12 calendar months and calculate HAP emissions according to Condition 2.5. The Permittee shall continue to multiply the results by the ratio between test results from Conditions 2.6b and 2.6c.

3. **Reporting.** Report as follows:

3.1 Report under the Operating Report of Permit No. 075TVP01, the following information:

a. the results of any crude oil sample analysis obtained under Condition 2.2 during the reporting period; and

b. the completed calculation spreadsheets showing the 12-month rolling total HAP emissions for each pollutant and the 12-month rolling aggregate total HAP emissions as calculated under Conditions 2.5 and 2.5a.

3.2 Report under Excess Emission and Permit Deviation Reports of Permit No. 075TVP01, if:

a. the 12-month rolling total individual HAP emissions from Tank 140 exceeds the limit in Condition 1;

b. the 12-month rolling total aggregate HAP emissions from Tank 140 exceeds the limit in Condition 1; or

c. the monitoring, recordkeeping, or reporting requirements are not in accordance with Conditions 2.1 through 2.5a.

Section 2 Permit Documentation

January 20, 2004	Construction Permit Application for Owner Requested Limits for TAPS Pump Station 4 dated December 2003.
September 8, 2004	APSC letter No. 1651 to ADEC. Re: Amendment to the TAPS Pump Station 4 HAP ORL Permit Application.
July 19, 2004	Letter from Don Mark Anthony, Alyeska, to Jim Baumgartner, ADEC, with Amendment to TAPS Pump Station 5 HAP ORL Permit Application.
October 21, 2004	Electronic mail from Don Mark Anthony, Alyeska, to Jeanette Brena, ADEC, with supplemental information to TAPS PS 5 HAP ORL permit application.
November 29, 2004	Comments to Pump Station 5 Preliminary Permit from Alyeska to ADEC.
January 7, 2005	Electronic mail from Keith Quincy (Hoefler Consultants) to ADEC. Re: PS 5 Draft Final HAP ORL Permit.
January 11, 2005	Electronic mail from Don Mark Anthony, Alyeska, to ADEC. Re: Proposed Condition 2.6.
January 12, 2005	Electronic mail from Don Mark Anthony, Alyeska, to ADEC. Re: Proposed Condition 2.6.

Appendix A

Appendix A – Procedure for HAP Content of Crude Oil Storage Tank Vapors

This Appendix provides a step-by-step procedure for determining the Hazardous Air Pollutants (HAPs) for the crude oil storage tank vapors. Alyeska will conduct laboratory tests of the crude oil to determine the weight fraction of various components. These weight fractions are then used, through many calculations, to determine the HAP emission rate from the tank.

I. Sample Description/Comments

1. Sample location ________________________________
2. Sample Date ________________________________
3. Sample ID. ________________________________
4. Core Laboratories data includes crude molecular weight and component wt% values.

II. Determine Component Mole Fractions in Liquid Crude

Methodology Assumptions/Comments:

1. The component mole fraction in crude is determined from component weight fraction and component molecular weight by assuming a mass of 1,000 lb of crude (see AP-42 Section 7.1.5).

2. The component molecular weight of Decanes+ is equal to the value required for the sum of all molecular weights to be equal to the Core Laboratories measured crude molecular weight of: _______lb/lb-mole

Liquid Crude Analysis Data		Calculate Component Mole Fraction in Crude			
Component **i**	Component Weight Fraction in Crude (wt%/100) **Z_{Li}**	Component Molecular Weight **M_i**	Total Moles of Crude (sum Z_{Li}/M_i x 1000) **x_T**	Component Mole Fraction in Crude ($Z_{Li}/M_i/x_T$) **x_i**	Crude Molecular Weight (sum M_i*x_i) **M_T**
Methane		16			
Ethane		30			
Propane		44			
Isobutane		58			
N-Butane		58			
1,3 Butadiene		54			
Isopentane		72			
N-Pentane		72			
N-Hexane		86			
Hexane		84			
Benzene		78			
Heptanes		97			
2,2,4 Trimethylpentane		114			
Toluene		92			
Octanes		111			
Ethyl Benzene		106			
Xylenes		106			
Isopropylbenzene		120			
Nonanes		123			
Naphthalene		128			
Decanes+					
SUM Z_{Li} / x_T / x_i / M_T	1.00			1.00	

Note:

1. Molecular weight values for component groups such as octanes are estimates from Core Laboratories.

III. Determine Component Vapor Pressure at Given Crude Temperature

Methodology Assumptions/Comments:
1. Clausius-Clapeyron equation provides relationship between temperature and vapor pressure:

$$\log P_2/P_1 = H_v/2.303R*(T_2-T_1/T_2T_1)$$

where R = Universal Gas Constant = 8.31448 J/g-mole·K = 3.58 Btu/lb-mole·K
H_v = Heat of Vaporization = see table below

2. Let P_1 be known component vapor pressure at known temperature T_1 = 100° F (311° K), and P_2 be unknown component vapor pressure at given crude temperature T_2 (shown below).

3. Pump station crude (and vapor) constant temperature (P_2) of: °F = °K
Based on average crude temperature at this pump station during the reporting period

Component Physical Properties			Component Vapor Pressure at Crude Temperature			
Component **i**	Component Vapor Pressure at 100°F (psia) **P_1**	Component Heat of Vaporization (Btu/lb-mole) **H_v**	Component Heat of Vaporization/ Gas Constant $H_v/2.303R$	Calculate $(T_2-T_1)/T_2T_1$	Calculate Inverse Log of (Hv/2.303R)* $(T_2-T_1)/T_2T_1$	Component Vapor Pressure at Crude Temperature (psia) **P_2**
Methane		3520	426.9			
Ethane		6349	770.1			
Propane		8071	978.9			
Isobutane		9136	1108.2			
N-Butane		9642	1169.5			
1,3 Butadiene		10025	1215.9			
Isopentane		10613	1287.3			
N-Pentane		11082	1344.2			
N-Hexane		12404	1504.5			
Hexane		12500	1516.1			
Benzene		13215	1602.8			
Heptanes		13500	1637.4			
2,2,4 Trimethylpentane		14000	1698.1			
Toluene		14263	1730.0			
Octanes		14500	1758.7			
Ethyl Benzene		15288	1854.3			
Xylenes		16000	1940.6			
Isopropylbenzene		16136	1957.1			
Nonanes		16500	2001.3			
Naphthalene		16700	2025.5			
Decanes+		47282	5734.7			

Notes:
1. Heat of Vaporization and vapor pressure of pure components from GPSA Engineering Data Book, Volume II, Section 23.
2. Vapor Pressure values for component groups such as octanes are estimates from Core laboratories.
3. Heat of Vaporization values for component groups are estimates based on values for individual components within the group.

IV. Determine Component Partial Pressure and Mole Fraction in Crude Vapor

Methodology Assumptions/Comments:

1. Conservatively assume C_1 through C_{10} hydrocarbons and HAP's are only species present in vapor phase due to dramatic dropoff in component vapor pressure as component molecular weight increases.

2. For speciation purposes, assume crude vapor pressure (P_{VA}) equal to sum of component partial pressures indicated below. This assumption ignores CO_2 present in crude and is conservative because it results in vapor mole fractions of listed components (including HAP's) being overstated.

3. Component partial pressure is equal to the component mole fraction in the liquid crude multiplied by the component vapor pressure at the given crude temperature:

$$P_i = P_2 * x_i$$

4. The component mole fraction in the crude vapor is then equal to the component partial pressure divided by the overall crude vapor pressure:

$$y_i = P_i / P_{VA}$$

	Calculation of Component Partial Pressure and Mole Fraction in Vapor			
Component **i**	Component Vapor Pressure at Crude Temperature (psia) **P_2**	Component Mole Fraction in Crude ($Z_{Li}/M_i/x_T$) **x_i**	Component Partial Pressure at Crude Temperature ($P_2 * x_i$) **P_i**	Component Mole Fraction in Vapor (P_i/P_{VA}) **y_i**
Methane				
Ethane				
Propane				
Isobutane				
N-Butane				
1,3 Butadiene				
Isopentane				
N-Pentane				
N-Hexane				
Hexane				
Benzene				
Heptanes				
2,2,4 Trimethylpentane				
Toluene				
Octanes				
Ethyl Benzene				
Xylenes				
Isopropylbenzene				
Nonanes				
Naphthalene				
Decanes+				

P_{VA} / y_i SUM				1.00

V. Determine Component Weight Fractions in Crude Vapor

1. Component weight fraction in the vapor is determined in two steps. First, the overall vapor molecular weight is determined by summing the product of the molecular weight and vapor mole fraction for each component:

$$M_v = \text{sum}\ (M_i{*}y_i)$$

2. Then, the component weight fraction is determined by dividing the product of the molecular weight and vapor mole fraction for each component by the overall vapor molecular weight:

$$Z_{vi} = (M_i{*}y_i)/M_v$$

Component Physical Properties		Calculation of Component Weight Fraction in Vapor		
Component **i**	Component Molecular Weight **M_i**	Component Mole Fraction in Vapor (P_i/P_{VA}) **y_i**	Calculate Vapor Molecular Weight (sum Mi*yi) **M_v**	Component Weight Fraction in Vapor ($M_i{*}y_i/M_v$) **Z_{vi}**
Methane	16			
Ethane	30			
Propane	44			
Isobutane	58			
N-Butane	58			
1,3 Butadiene	54			
Isopentane	72			
N-Pentane	72			
N-Hexane	86			
Hexane	84			
Benzene	78			
Heptanes	97			
2,2,4 Trimethylpentane	114			
Toluene	92			
Octanes	111			
Ethyl Benzene	106			
Xylenes	106			
Isopropylbenzene	120			
Nonanes	123			
Naphthalene	128			
Decanes+				
y_i SUM / M_v / Z_{vi}SUM		1.00		1.00

Estimated Actual HAP Emissions – Breakout Tank
Pump Station 4

1. The TOC emissions (losses) are determined from EPA's TANKS 4.0 Program. Individual component emission rates (losses) are then determined using the vapor phase weight fractions previously determined for each component.

$$L_{Ti} = (Z_{vi})(L_T)$$

2. Based on an actual flow of crude to the breakout tank of: ____________________ bbl/yr
____________________ gal/yr

The Total TOC losses from the breakout tank are: ____________________ lb/yr
____________________ tpy

Calculation of Component Emission Rates (Losses)				
Component **i**	Component Weight Fraction in Vapor **Z_{vi}**	TOC Losses (from TANKS) **L_T**	Component Emission Rate/Loss **L_{Ti}**	Total HAP Emission Rate/Losses **L_{HAP}**
Methane				N/A
Ethane				N/A
Propane				N/A
Isobutane				N/A
N-Butane				N/A
1,3 Butadiene				
Isopentane				N/A
N-Pentane				N/A
N-Hexane				
Hexane				N/A
Benzene				
Heptanes				N/A
2,2,4 Trimethylpentane				
Toluene				
Octanes				N/A
Ethyl Benzene				
Xylenes				
Isopropylbenzene				
Nonanes				N/A
Naphthalene				
Decanes+				N/A
L_{Ti} SUM / L_{HAP} SUM				

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION

TECHNICAL ANALYSIS REPORT
For Air Quality Control Permit No. AQ0075CPT03
Project X-208

Alyeska Pipeline Service Company
Pump Station 4

HAZARDOUS AIR POLLUTANTS OWNER REQUESTED LIMITS

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Prepared by: Zeena Siddeek
Supervisor: Bill Walker
Date: Final October 28, 2005

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1. Introduction

This Technical Analysis Report (TAR) provides the Alaska Department of Environmental Conservation's (the department's) basis for issuing an air quality construction permit (AQ0075CPT03) to Alyeska Pipeline Service Company (Alyeska) for Pump Station 4 (PS4).

1.1. Project Description

Alyeska submitted a construction permit application to the department to obtain Owner Requested Limits (ORLs) for PS4. The ORLs are voluntary in nature and are not needed to avoid any requirement to obtain a permit under 18 AAC 50 or AS 46.14 because no physical or operational change is associated with the project. The purpose of the ORLs is to establish limits that are enforceable for PS4 to be classified as a Hazardous Air Pollutant (HAP) synthetic minor source.

Alyeska submitted the application in January 20, 2004 and an amendment to the application on September 8, 2004. The department has agreed to process the application, including any amendments, in accordance with 18 AAC 50 as in effect prior to October 1, 2004[1].

The department intends to incorporate the terms and conditions of this construction permit into the operating permit as an administrative revision after EPA's 45-day review period under 18 AAC 50.370(a)(8).

1.2. Stationary Source Description

PS4 is an existing crude oil pumping station (SIC code 4612) located 144 miles south of Prudhoe Bay, Alaska. PS4 is part of the Trans Alaska Pipeline System (TAPS) that transports crude oil from the North Slope of Alaska to the Valdez Marine Terminal. The area surrounding is classified as attainment or unclassifiable for all pollutants and is classified as a Class II area. PS4 is currently classified as a PSD major stationary source under 18 AAC 50.300(c)(1) because it has the potential to emit more than 250 tpy of a regulated air contaminant.

PS4 contains of a breakout tank for the storage of crude oil in the event of a pipeline slowdown or shutdown. Other emission units at PS4 after the strategic reconfiguration of the TAPS pump stations, will consist of two 12,900 kW natural gas fired Siemens Cyclone Turbine Generators, two 5.0 MMBtu/hr gas fired heaters, one 1750 kW reciprocating internal combustion engine (RICE) and one 65 kW RICE. The revised equipment list after the strategic reconfiguration was taken into account when developing HAP ORLs in this permit.

1.3. Permit History

The most recent permit issued for this stationary source is Construction Permit AQ0075CPT02 issued on February 14, 2005 for strategic reconfiguration of PS4. Previous construction permits include Permit No. 075CP01 issued on March 11, 2003 to revise allowable fuel gas H_2S content

[1] Alaska's air quality permit program and associated regulations underwent a major revision that became effective October 1, 2004. Applicants who submitted a complete permit application prior to this date have the option of having their applications processed under either the "new" or "old" program. Per APSC's request, the department is processing the PS4 application under the old program/regulations.

and permit No. 9872-AC024 issued on December 4, 1998 to amend terms and conditions of Permit to Operate No. 9572-AA009 issued under the pre 1997 regulations. The Operating Permit No. 075TVP01 issued on October 13, 2003, replaced AQC Permit No. 9572-AA009 for PS4.

PS4 is currently regulated under Operating Permit No.075TVP01 and construction Permit Nos. 9872-AC024, 075CP01, and AQ0075CPT02.

2. Stationary Source Emissions

2.1 Owner-Requested Limits

Under 18 AAC 50.225(a) and 18 AAC 50.305(a)(4) an owner or operator may avoid a requirement to have a permit under AS 46.14 or 18 AAC 50, if the department approves enforceable limits on a source's ability to emit air pollutants. These owner requested limits allows the stationary source to avoid classification as a HAP major stationary source under 18 AAC 50.300(f). A HAP major stationary source is one that emits or has the potential to emit 10 TPY or more of any single hazardous air pollutant or 25 TPY or more in aggregate of two or more HAP's.

Alyeska wants to obtain ORLs under 18 AAC 50.305(a)(4) to classify PS4 as a synthetic minor by limiting potential emissions to less than HAP major threshold of 10 TPY for individual HAPs and 25 TPY for aggregate HAPs. To stay under the HAP major thresholds, Alyeska specifically wants to restrict the potential emissions from the crude oil breakout tank at PS4 (Tank 140). Alyeska is not requesting limits for any other existing emission units in the current permit action. Emissions from turbines, heaters, engines, incinerators, piping fugitives and storage tanks are based on unrestricted potential emissions or existing operational limits where applicable.

Alyeska has specifically requested the following limitations pursuant to 18 AAC 50.305(a)(4):

1. Limit HAP emissions from Tank 140 to no greater than 8.0 TPY for any individual HAP, and

2. Limit HAP emissions from Tank 140 to no greater than 16.9 TPY for all HAPs in aggregate.

The ORL's for the breakout tank listed above will ensure that the total stationary source-wide potential HAP emissions are 90 percent of both the 10 TPY for individual HAPs and the 25 TPY for aggregate HAP's

2.2 Breakout Tank Emissions

The purpose of the crude oil breakout tank is to store crude oil in the event of a pipeline shutdown. The breakout tank has the greatest potential for HAP emissions due to the vaporization of volatile HAPs present in the crude emitted from the tank along with the crude vapors.

The HAP emissions from the breakout tank is proportional to the amount and composition of the crude vapors. The amount of crude vapors is a function of crude oil volatility, temperature, crude throughput rate flow rate into the tank and the crude vapor composition is a function of crude oil composition. The variation in flow, crude volatility, temperature and the crude composition makes it difficult to determine the true potential emissions of the breakout tank. Alyeskas proposed method to calculate actual HAP emissions from the breakout tank is described in Appendix A.

2.3 Stationary Source Actual Emissions

Table 1 presents a summary of actual HAP emissions. The actual emissions for the breakout tank is based on crude composition at PS1 taken in 2002 and crude throughput in 2001 and 2002. Actual emissions from emission units prior to the reconfiguration consisting of diesel engines, natural gas fired heaters, dual fuel fired turbines are based on actual fuel use. Emissions from the incinerator is based on the capacity and actual operations. A description of the methods used in emission estimates is listed in Appendix A of this technical analysis report.

Table 1. Summary of Actual HAP Emissions

Emission Unit Category	Actual Emissions (tons per year)	
	Highest Individual HAP	Total of All HAP's
Breakout Tank	N-Hexane 1.4	02.0
Diesel Engines	Formaldehyde 0.00003	0.0001
NG-Fired Heaters	N-Hexane 0.2	0.5
NG and Diesel-Fired Turbines	Formaldehyde 0.5	1.5
Waste Incinerator	Hydrochloric Acid 0.07	0.1
Fugitives	N-Hexane 0.3	0.9
TOTAL – Stationary Source	N-Hexane 2.1	5.0

2.4 Stationary Source Potential Emissions

Alyeska selected the hypothetical, worst-case mass flow rate of crude oil of approximately 1,675,000 barrels per year. Using this flow rate Alyeska calculated the potential HAP emissions for the breakout tank. Contributing to the total stationary source potential HAP emissions are those from the new engines, drag reducing agent (DRA) storage tank and piping fugitives.

Table 2 presents the potential HAP emissions based on the proposed breakout tank ORL and unrestricted operation of all other emission units. As shown in Table 2, the stationary source potential emissions are less than 90% of the 10 TPY per individual HAP or 25 TPY per aggregate HAP thresholds.

Table 2 also shows that the potential HAP emissions from each of the emission units other than the breakout tank contribute small amounts to the total stationary source HAP emissions. Because of the small amount of potential emissions from this equipment, the department is requiring active monitoring of only the breakout tank and the HAPs emitted from that emission unit and not from any other emission units.

Table 2. Summary of Potential HAP Emissions under Proposed ORLs

Emission Unit Category	Potential Emissions (tons per year)	
	Highest Individual HAP	Total of All HAP's
Breakout tank (with ORL)	N-Hexane 8.0	16.9
Diesel Engines	Formaldehyde 0.006	0.02
NG-Fired Heaters	N-Hexane 0.08	0.2
NG-Fired Turbines	Formaldehyde 0.8	2.2
Waste Incinerator	Hydrochloric Acid 1.4	1.4
Fugitives	N-Hexane 0.5	1.8
TOTOAL- Stationary Source	N-Hexane 8.6	22.5

2.5 Monitoring Breakout Tank Emissions

HAP emissions under the worst-case flow rates will vary slightly over time due to the change in composition of the crude oil stream as the percentage of the total flow attributable to field crude oil property changes, new fields coming on-line, and changes in the ratio of oil from specific producing fields. Some oil fields produce crude oil with higher percentage of VOC and HAP ratios than other fields. North Slope production changes and transportation techniques, such as natural gas liquid injection cause the crude oil properties to constantly fluctuate. Because of this, the department requires that Alyeska sample the crude stream once every three months for the first year, and semi annually for the second year and then annually thereafter. The monitoring requirement is the same for HAP ORL for Pump Station 5 (PS5) as described in Permit No. 098CP01 issued on March 9, 2005. Therefore, the department gave Alyeska the option to use the data collected to satisfy the requirements for PS5 in lieu of collecting separate data for PS1.

Since actual emissions are well below the ORLs, Alyeska is given the option to calculate and record the 12 month rolling HAP emissions at six month intervals to coincide with the time of the semiannual Operating Reports are due under the source's operating permit, if HAP emissions from the most recent calculations show less than 50% of the limit for both individual and combined HAP emissions for each 12 month rolling period. However, if the most recent calculations show that HAP emissions for either individual or combined exceed 50% for any 12 month rolling period then Alyeska is required to calculate and record on a monthly basis.

In addition, if the calculated HAP emissions exceed 90% of either of the ORLs the department requires that Alyeska validate their crude oil sampling methodology for HAP emissions using headspace vapor analysis by the Gas Producers Association Method 2286 using any one of the breakout tanks at pump stations 3, 4, 5, 7 and 9. If the crude oil sampling method predicts higher emissions the headspace sampling method, Alyeska will continue to calculate the HAP emissions according to the crude oil sampling methodology. If the crude oil sampling method predicts lower emissions than the headspace sampling method, then Alyeska is required to calculate HAP emissions at quarterly intervals and multiply the results by the ratio between the test results of head space analysis and the crude oil sampling. Once the HAP emissions fall below 90% of the limits, Alyeska is required to continue multiplying the results by the ratio between the head space vapor analysis results and the crude oil sampling results. The department's intent is to confirm that Alyeska's calculation methodology provides an adequate representation of the HAPs actually emitted from the tank.

3. Applicable Standards

For each stationary source or modification subject to construction permitting, the applicant must show that the proposed emission units comply with state and federal emission standards. The department has adopted federal New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPs), by reference in 18 AAC 50.040. In addition, the department has source-specific emission standards listed in 18 AAC 50.050 through 50.090.

The Statement of Basis for Operating Permit No. 075TVP01 describes the standards applicable to existing equipment. Since Alyeska is not proposing any new emission units under the current permit action, no new applicable standards apply.

3.1 New Source Performance Standards (NSPS)

The EPA promulgates and implements NSPS. The intent of NSPS is to provide technology-based emission control standards. EPA may delegate to each state the authority to implement and enforce standards of performance for new stationary sources located in that state. The department has incorporated by reference the NSPS effective July 1, 2001, for specific industrial activities, as listed in 18 AAC 50.040. However, EPA has not delegated to the department the authority to administer the NSPS program at this time.

3.2 National Emissions Standards for Hazardous Air Pollutants (NESHAP)

Subpart HH: National Emissions Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities could deal with facilities such as Pump Station 1. However, after reviewing the exception to the subpart, this facility is exempt. In Sec. 63.760(e)(1) it says, "a facility that exclusively processes, stores or transfers black oil is not subject to the requirements of this subpart (HH). For the purposes of this subpart, a black oil facility that uses natural gas for fuel or generates gas from black oil shall qualify for this exemption."

4. Ambient Air Quality Impact Analysis

Alyeska's Owner Requested Limits does not increase emissions of any pollutants. Therefore the proposal does not trigger a review of ambient air quality and does not trigger any of the department's mandatory modeling requirements.

5. Permit Administration

5.1 Permit Terms and Conditions

This permit contains the terms and conditions under which Alyeska is authorized to implement the Owner Requested Limits to avoid PS4 classification as HAP major.

5.2 Standard Conditions

Standard permit conditions listed in 18 AAC 50.346(a) applicable to operating and construction permits—specifically emission fees, air pollution prohibited, excess emission and permit deviation reports—are already listed in initial Operating Permit No. 075TVP01. This project does not trigger any changes to these conditions so they are not included in this construction permit except by reference to the operating permit.

5.3 Preliminary Decision

The department's Title V Office has oversight for all reports, surveillance, records and inspections of permitted stationary sources. Therefore, Alyeska shall submit all plans, reports (except excess emission reports), and notices required under this permit to the Title V Fairbanks office, as provided for in Section 10 of initial Operating Permit No. 075TVP01. The permit requires excess emission and permit deviation reports be submitted as set out in Operating Permit No. 075TVP01.

APPENDIX A

Emissions Calculation Methodology

The type and quantity of HAP's emitted from the breakout tank is directly related to the composition of these constituents in the crude oil and crude vapor. The following general discussion describes the calculation methodology used by Alyeska, with some additions or slight changes in the presentation. Except where noted, the methodologies apply to both actual and potential HAP emissions calculations.

Crude Vapor Speciation. The ORL's are developed based on a sampling of North Slope crude in the PS 1 discharge stream. This stream is representative of the mix of the various producer streams flowing down the TAPS and making up the crude in Tank 140. Alyeska proposes to sample this crude stream periodically as part of the compliance monitoring for the ORL. The department believes a tiered approach is necessary to ensure that a representative average of the crude oil is collected and to track trends and changes in the crude oil constituents.

On October 31, 2002 Alyeska collected a sample near Pump Station 1 using their existing crude oil sampling methodology. The sample was analyzed by Core Laboratories using four analyses:

- Liquid phase component speciation, including $C_1 - C_{10}$ hydrocarbons, and nine individual HAP's, using ASTM Method 5134 Modified;
- Vapor phase hydrogen sulfide (H_2S) content, via ASTM D-5705;
- Molecular weight, using Freezing Point Depression; and
- Reid Vapor Pressure, via ASTM D-5191.

The liquid phase component speciation and crude molecular weight are used to determine the crude vapor composition. The H_2S content and the Reid Vapor Pressure are not utilized to determine HAP emissions.

Alyeska used the methodology described in AP-42, Section 7.1.4 to determine the HAP content of the crude vapors.

Breakout Tank Emissions. Along with the amount of crude entering the breakout tank, the weight fraction of HAPs in the crude vapor is the key information needed to calculate breakout tank HAP emissions. Alyeska used the TANKS 4.0 model and the speciation methodology described in AP-42, Section 7.1.4 to determine the HAP content of the crude vapors. Appendices B and E of the application describe the methodology in detail.

Combustion Equipment Emissions. Heater and turbine HAP emissions were determined using the emission factors in AP-42. Diesel engine and incinerator HAP emissions were determined using AP-42 emission factors and actual or allowable operation. Please refer to Alyeska's September 8, 2004 supplement to permit application, Appendices C and D for further details.

Fugitives Emissions. Fugitive HAP emissions have been estimated in a two part process. First, total organic compound (TOC) emissions from piping leaks were determined based on a widely used methodology documented in the USEPA's Protocol for Equipment Leak Emission Estimates. This document provides fugitive TOC emission factors for equipment in both liquid and gas service that were developed through extensive studies. In 1998, Alyeska conducted a fugitive emissions analysis using these factors and facility-specific parameters (piping type and count) determined through an on-site study of three representative pump stations. The PS4 TOC emissions determined in the 1998 study were then speciated into HAP emissions using the Core crude composition data. Please refer to Alyeska's application, Appendix F for further details.

Fuel Storage Tanks. Fuel oil to power the turbines and heaters in the event that natural gas is unavailable is stored in tanks. Using the permitted fuel use in of approximately 2.1 million gallons per year as the annual throughput and conservatively assuming that the fuel is kerosene rather diesel, the USEPA's computer model TANKS 4.0 indicates that TOC emissions are less than 00 pounds per year. Because the HAP content of diesel fuel can be expected to be less than 2 percent, this source category has no meaningful contribution to facility actual or potential HAP emissions.

F.4 Permit No. AQ0075CPT04

STATE OF ALASKA

DEPT. OF ENVIRONMENTAL CONSERVATION

Division of Air and Water Quality - Air Quality Maintenance

TONY KNOWLES, GOVERNOR

410 Willoughby Avenue, Suite 105
Juneau, Alaska 99801-1795
Phone: (907) 465-5100
FAX: (907) 465-5129
http://www.state.ak.us/dec/home.htm

DEC 11 REC'D

CERTIFIED MAIL NO.: P 692 141 732
RETURN RECEIPT REQUESTED

December 4, 1998

Mr. Don Mark Anthony
Alyeska Pipeline Service Company
1835 South Bragaw Street
Anchorage, AK 99512

Re: Construction Permit Application for Alyeska Pump Station 4, Air Quality Permit to Operate No. 9572-AA009

Dear Mr. Mark Anthony:

On October 7, 1997, the Department of Environmental Conservation (ADEC) received the Alyeska Pipeline Service Company's (Alyeska) application for an Air Quality Control Permit to Construct for the Alyeska Pump Station 4. The application requested a revision of terms and conditions of Air Quality Control Permit No. 9572-AA009 in accordance with 18 AAC 50.305(a)(3). The request included deletion of the 300 lbs/hr operational limit for the solid waste incinerator, deletion of the 9,687 scf/hr natural gas per turbine, monthly average limit for the Garrett turbine electric generators, deletion of the 23,870 scf/hr natural gas per heater, monthly average limit for the Eclipse heaters, deletion of the 200 hr/yr limit on the diesel-fired fire pump, and deletion of the 70 ppmv NOx corrected to 15% O_2 ISO conditions limit for operation on gas fuel for the Avon Gas Generators. The Department has reviewed the application and approves the Construction Permit Application. See the Technical Analysis Report "Alyeska Pipeline Service Company Various Pump Stations" dated November 2, 1998, for a detailed discussion of the approvals.

The amended pages of the Air Quality Permit to Operate No. 9572-AA009 are enclosed. This letter and the enclosed amended pages constitute Air Quality Control Construction Permit 9872-AC024. Please substitute the pages amended here for the appropriate pages in your current permit.

Department regulations provide that if you disagree with this decision you may request an adjudicatory hearing in accordance with 18 AAC 15.200-910. The request should be mailed to the Commissioner, Alaska Department of Environmental Conservation, 410 Willoughby Avenue, Suite 105, Juneau, Alaska 99801-1795, by Certified Mail, Return Receipt Requested. If a hearing is requested, one copy of the request should be sent to the undersigned. Failure to submit a request within thirty days of service of this letter shall constitute a waiver of your right to administrative review of this decision. In addition, any other person who disagrees with this decision may request an adjudicatory hearing within thirty days of the service of this letter. Any hearing granted will be limited to the matters related to the issue of these amendments. You are reminded that even if an adjudicatory hearing has been requested and granted, all permit conditions remain in full force and effect.

Sincerely,

John F. Kuterbach
Supervisor, Program Development

JFK/DEB/pal (r:\airfacs\apscps04\construction\x32\ps4mod.doc)
Enclosures

cc: ADEC/AQM, Anchorage
ADEC/AQM, Fairbanks

B. OPERATING AND MAINTENANCE REQUIREMENTS

3. Permittee shall install, maintain and operate, in accordance with manufacturer's specifications, fuel burning equipment, process equipment, emission control devices, testing equipment, and monitoring equipment in accordance with information contained in the documents listed in Exhibit E of this permit, to provide optimum control of air contaminant emissions during all operating periods.

4. Permittee shall neither modify nor replace any of the fuel burning equipment, listed in Exhibit A which might result in increased potential air contaminant emissions or constitutes a modification as described by 18 AAC 50.900(28), without first notifying the Department 30 days in advance. The notification must be in writing and must include a description of the proposed change and an estimate of any change in the quantity of emissions of each regulated air contaminant which may occur as the result of the modification or replacement.

5. Permittee shall burn no more fuel than specified in Exhibit B for the sources indicated.

6. Permittee shall not burn liquid fuel with a sulfur content greater than 0.30%, by weight.

7. Deleted by Construction Permit 9872-AC024.

8. Permittee shall not operate Avon gas generators on liquid fuel for more than 1,250 hours, or 869,450 gallons per year, combined total, whichever is less. Permittee shall not operate more than two Avon gas generators on liquid fuel at any time.

9. Permittee shall not operate the Garrett turbine electric generator sets on liquid fuel for more than 1,500 hours or 96,000 gallons per year, combined total, whichever is less.

10. Permittee shall not operate the Eclipse Heaters on liquid fuel for more than 1,000 hours or 159,000 gallons per year combined total, whichever is less.

11. Permittee shall not operate the sewage stack injection unless the reaction turbine speed is above 2350 rpm and the exhaust temperature is at least 750 degrees Fahrenheit.

C. SOURCE TESTING REQUIREMENTS

12. If requested by the Department, permittee shall, within 60 days, perform source tests of any source identified in Exhibit A of this permit, using the applicable Performance

EXHIBIT B (cont.)

Source and Parameter	Operating Limit or Fuel Specification
Avon Gas Generators Liquid Fuel Use	Not more than two units operating at any time and only 1,250 hours or 869,450 gallons per year, combined total, whichever is less.
Solar Turbine Electric Generator	100 gal/hr fuel oil, monthly average.
Garrett Turbine Electric Generators (3)	1,500 hours per year on liquid fuel, combined total, for all three turbines. 96,000 gallons per year of liquid fuel, combined total for all three turbines.
Eclipse Heaters (2)	1000 hours per year on liquid fuel, combined total, for 2 heaters. 159,000 gallons per year of liquid fuel, combined total, for 2 heaters.

EXHIBIT B (cont.)

Air Contaminant Source Source Class or Numbers	**Performance Based Emission Limit, Operating Limit or Fuel Specification**	**Estimated Potential Annual Emissions (tpy)**
C. NITROGEN OXIDES		**Total 625.9**
Avon Gas Generators		
Liquid Firing	140 ppmv NOx corrected to 15% O_2 ISO conditions, and for operation On liquid fuel	517.7
	<Increase over Gas Emissions Only>	25.9
Garrett Turbines		
Gas Firing		31.8
Liquid Firing	<Increase over Gas Emissions Only>	0.9
Solar Turbine		18.5
Heaters		
Gas Firing		29.2
Liquid Firing	<Increase over Gas Emissions Only>	<0.1
Solid Waste Incinerator		1.3
Firewater Pump		0.6

EXHIBIT D
FACILITY OPERATING REPORT

Two copies of the Facility Operating Report shall be submitted to the Department's Fairbanks Office, Air Quality Maintenance Section, 610 University Avenue, Fairbanks, Alaska 99709-3643, quarterly by January 30, April 30, July 30, and October 30 of each year. The report shall include the following information:

1. Facility identification: Name of company, facility name and location, and permit number.

2. The date and period of time covered by the report.

3. Operating time and fuel consumption for each month. Include:

   a. the number of days or hours of operation for each source identified in Exhibit A;

   b. a listing of the total number of hours the Solar turbine electric generator operated each month;

   c. the type and quantity of fuel burned in each source or group of sources and the total quantity of fuel burned at the facility, in MMscf or gallons per day. Indicate if fuel consumption is calculated rather than measured with a fuel flow meter;

   d. deleted by Construction Permit 9872-AC024;

   e. gallons of sewage effluent injected, monthly, determined from potable water meter readings and records of any other volumes of injected effluent greater than 30 gallons per day not accounted for by the potable water meter; and

   f. list by date the daily average temperature and daily fuel consumption for each Avon gas generator.

4. Fuel quality: Report the concentration of H_2S in the fuel gas in ppm for the quarter. Report the liquid fuel sulfur content and indicate whether it was from a sample or based on the monthly analysis of the supplier.

5. Excess Emissions: Summary of the information submitted under Condition 20; include date of occurrence, equipment affected, and estimated amount of material burned or released.

6. Signature of authorized agent preceded by the statement:

   "I am familiar with the information contained in this report and, to the best of my knowledge and belief, such information is true, complete and accurate."

F.5 Permit No. AQ0075MSS02

DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY CONTROL MINOR PERMIT

Permit No.: AQ0075MSS02
Revises Permit No. AQ0075CPT02
Rescinds Permit No. AQ0075MSS01

Date: **Final – March 26, 2008**

The Alaska Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Minor Permit No. AQ0075MSS02 to the Permittee listed below.

Operator and Permittee:	**Alyeska Pipeline Service Company** PO Box 196660 Anchorage, AK 99519-6660
Owner:	Owners of the Trans-Alaska Pipeline System
Stationary Source:	Trans-Alaska Pipeline System Pump Station 4
Project:	Strategic Reconfiguration Emission Units Revision
Location:	Latitude: 68° 25' 23" North; Longitude: 149° 21' 18" West
Physical Address:	Sections 5 and 8, T12S, R12E Umiat Meridian
Permit Contact:	Don Mark Anthony (907) 450-7652

This project is classified under 18 AAC 50.502(c)(3) for air quality protection because the increase in potential to emit of NO_X exceeds 10 tpy. It is also classified under 18 AAC 50.508(6) to revise or rescind terms and conditions of a Title I permit. The permit satisfies the obligation of the Permittee to obtain a minor permit under 18 AAC 50.

This permit authorizes the Permittee to operate under the terms and conditions of this permit, and as described in the original permit application and subsequent application supplements listed in Section 2 except as specified in this permit.

The Permittee may operate under the provisions of this minor permit upon issuance

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for Sally A. Ryser

John F. Kuterbach
Manager, Air Permits Program

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Section 1 Permit Terms and Conditions

Construction Permit No. AQ0075CPT02 Revisions

1. The following paragraph on the Title Page of Construction Permit No. AQ0075CPT02 dated February 14, 2005:

   The Department authorizes the Permittee to install two turbines, two reciprocating internal combustion engines, and two boilers at Pump Station 4 as part of the **Strategic Recongifuration Project.**

   is rescinded and replaced with the following:

   The Department authorizes the Permittee to install two turbines, two reciprocating internal combustion engines, eleven shop heaters and two portable generators at Pump Station 4 as part of the **Strategic Reconfiguration Project.**

2. Footnote 1 on page 3 of Construction Permit No. AQ0075CPT02 dated February 14, 2005 is rescinded.

Table 1 - Construction Permit Emission Unit Inventory[a]

No.	Type	Make/Model	Fuel	Rating/Size
12	Combustion Turbine Generator with DLE	Siemens Cyclone	Natural Gas/Diesel	12.9 MW ISO
13	Combustion Turbine Generator DLE	Siemens Cyclone	Natural Gas	12.9 MW ISO
14	Reciprocating Internal Combustion Engine	Caterpillar 3516B	Diesel	2,250 kW
15	Reciprocating Internal Combustion Engine	To Be Determined (TBD)	Diesel	65 kW-e
18	Miscellaneous Shop Heaters (11)	Various	Natural Gas	3.28 MMBtu/hr, combined
19	Reciprocating Internal Combustion Engine	Navistar XQ200 Generator	Diesel	250 kWe
20	Reciprocating Internal Combustion Engine	Navistar XQ200 Generator	Diesel	250 kWe

Table Notes:
a Except as noted elsewhere in this permit, the information in this table is for identification purposes only.

3. Condition 1.2 of Construction Permit No. AQ0075CPT02 dated February 14, 2005 is rescinded and replaced with the following (no change to the footnote):

1.2 At least five days before initial startup[3] of Emission Units 12 through 15, and 18, or replacement units, submit the following to the Department's Fairbanks office:

a vendor specification sheets that identify the unit type, make and model (including model number), serial number, and rating/size; and

b the expected installation date and estimated date of startup.

4. Condition 1.3 of Construction Permit No. AQ0075CPT02 dated February 14, 2005 is rescinded and replaced with the following (no change to the footnote):

1.3 Unless an extension is granted by the Department in writing as indicated in condition 1.5, decommission[4] existing Emission Units 1 through 7 listed in Table 1 of initial Operating Permit No. AQ0075TVP01 within 270 calendar days after actual initial startup of any Emission Unit 12 through 15 or replacement unit.

5. Condition 1.4 of Construction Permit No. AQ0075CPT02 dated February 14, 2005 is rescinded and replaced with the following:

1.4 Unless an extension is granted by the Department in writing as indicated in condition 1.5, decommission existing Emission Units 8 and 9 listed in Table 1 of initial Operating Permit No. AQ0075TVP01 within 270 calendar days after actual initial startup of Emission Unit 18 or replacement unit.

6. Condition 1.5 of Construction Permit No. AQ0075CPT02 dated February 14, 2005 is rescinded and replaced with the following:

1.5 The Department may allow an extension of the "startup period" for due cause. Submit a request for an extension in writing to the Department's Fairbanks office within 240 days of initial startup of any Emission Unit 12 through 15 and 18 or replacement unit. Include a description of the reason for the extension. The Department will grant an extension of up to 90 days if the Department finds due cause exists.

7. Condition 1.6 is added to Construction Permit No. AQ0075CPT02 dated February 14, 2005 as the following:

1.6 Include with the next operating report described in condition 45 of initial Operating Permit No. AQ0075TVP01:

a. the actual initial startup dates for each Emission Unit 12 through 15 and 18 through 20 or replacement units;

b. the decommissioning dates for each Emission Unit 1 through 9; and

c. copies of the notifications and records required by conditions 1.1 and 1.2.

8. Condition 2 and sub-condition 2.1 of Construction Permit No. AQ0075CPT02 dated February 14, 2005 are rescinded and replaced with the following (No change to sub-conditions 2.2 through 2.4):

2. Operational Limits (NO_X, SO_2). The Permittee shall restrict the12 consecutive month total operating hours of Emission Units 12, 14, 15, 19 and 20 to less than the limits listed in Table 2 to protect ambient air quality standards and increments.

Table 2 – Operating Hour Limits

Emission Unit No.	12-Consecutive Month Hourly Limit, in hours
12	240 on diesel fuel
14	600 total
15	300 total
19 and 20	10,000 combined total

2.1 For each month, monitor and record the hours that Unit 12 operated on diesel fuel, the total hours of operation for Units 14 and 15, and the combined total hours of operation for Units 19 and 20.

9. Condition 7 of Construction Permit No. AQ0075CPT02 dated February 14, 2005 is rescinded.

10. Condition 28 and sub-conditions 28.1 through 28.2 of Construction Permit No. AQ0075CPT02 dated February 14, 2005 are rescinded and replaced with the following:

28. Visible Emissions The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from Emission Units 12 through 15 and 18 through 20 to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.

28.1 For Emission Unit 13 and 18 (gas-fired units), verify compliance with the visible emission standard by certifying annually in accordance with condition 46 of initial Operating Permit No. AQ0075TVP01 whether the unit burned only fuel gas. Report as a permit deviation as described in condition 43 of initial Operating Permit No. AQ0075TVP01 if other fuel was burned in the unit.

28.2 For each Emission Units 12, 14, 15, 19 and 20 (dual and liquid fuel fired units), comply as follows while using liquid fuel:

a. Verify initial compliance with the visible emission standard using either condition 28.2(a)(i) or 28.2(a)(ii).

(i) Prior to unit installation, obtain a certified manufacturer guarantee that each emission unit will comply with the visible emission standard and attach a copy of the guarantee to the next operating report described in condition 45 of initial Operating Permit No. AQ0075TVP01.

(ii) Conduct a visible emission observation in accordance with Section 9 of initial Operating Permit No. AQ0075TVP01 within 90 days after each unit is first fired on liquid fuel. Attach a copy of the Method 9 surveillance records to the next operating report described in condition 45 of initial Operating Permit No. AQ0075TVP01.

b For each Emission Units 12, 14 and 15 that operates more than 400 hour per calendar year on liquid fuel, monitor, record, and report as described in Section 13 of initial Operating Permit No. AQ0075TVP01.

11. Condition 29 and sub-conditions 29.1 through 29.2 of Construction Permit No. AQ0075CPT02 dated February 14, 2005 are rescinded and replaced with the following:

29. Particulate Matter (PM). The Permittee shall not cause or allow PM emission from any Emission Unit 12 through 15 and 18 through 20 to exceed 0.05 grains per dry standard cubic foot (gr/dscf) of exhaust gas corrected to standard conditions and averaged over three hours.

29.1 For Emission Unit 13 and 18, the Permittee shall comply with condition 28.1.

29.2 For Emission Units 12, 14, and 15, the Permittee shall comply with monitoring, recordkeeping, and reporting for liquid fuel-fired equipment as described in initial Operating Permit No. AQ0075TVP01, condition 5 and Section 13.

12. Condition 30 of Construction Permit No. AQ0075CPT02 dated February 14, 2005 is rescinded and replaced with the following:

30. Sulfur Compound Emissions. The Permittee shall not cause or allow sulfur compound emission, expressed as SO_2, from any Emission Unit 12 through 15 and 18 through 20 to exceed 500 ppm averaged over three hours. Monitor, record, and report as described in condition 6 of initial Operating Permit No. AQ0075TVP01.

Maintenance Requirements

13. Maintenance. The Permittee shall maintain equipment according to manufacturer's or operator's maintenance procedures.

Fee Requirements

14. Condition 2.1 in Operating Permit No. 075TVP01 dated October 1, 2003 is rescinded and replaced with the following:

2.1 the stationary source's assessable potential to emit of 1,233 TPY; or

Terms to make Permit Enforceable

15. 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

15.1 an enforcement action; or

15.2 permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280.

16. 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.

17. 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.

18. 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.

19. The permit does not convey any property rights of any sort, nor any exclusive privilege.

Section 2 Permit Documentation

November 6, 2007	Minor Permit Application for APSC's Pump Station 4.
January 31, 2008	Aerial Photos of PS4 submitted by APSC.
February 4, 2008	Trailer Specifications submitted by APSC.
March 12, 2008	Comments submitted by APSC on preliminary decision to approve application.

F.6 Permit No. AQ0075MSS03

DEPARTMENT OF ENVIRONMENTAL CONSERVATION

AIR QUALITY CONTROL MINOR PERMIT

Permit AQ0075MSS03 Final – September 30, 2010

The Alaska Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Minor Permit AQ0075MSS03 to the Permittee listed below.

Operator and Permittee:	**Alyeska Pipeline Service Company (APSC)** P.O. Box 196660 Anchorage, AK 99519-6660
Owner:	BP Pipelines (Alaska) Inc. Exxon Mobil Pipeline Company Conoco Phillips Transportation Alaska Inc. Unocal Pipeline Company Koch Alaska Pipeline Company, LLC
Stationary Source	**Trans-Alaska Pipeline System (TAPS) Pump Station 4 (PS4)**
Location:	Latitude: 68° 25' 23" North; Longitude: 149° 21' 18" West
Physical Address:	Sections 5 and 8, T12S, R12E Umiat Meridian
Permit Contact:	Don Mark Anthony, (907)450-7652
Project:	Add A Generator and New ORL

This project is classified under 18 AAC 50.508(5) to add a new ORL. It is also classified under 18 AAC 50.508(6) to revise or rescind terms and conditions of a Title I permit. The permit satisfies the obligation of the Permittee to obtain a minor permit under 18 AAC 50.

This permit authorizes the Permittee to operate under the terms and conditions of this permit, and as described in the original permit application and subsequent application supplements listed in Section 6 except as specified in this permit.

F. Z. Siddiqui

for John F. Kuterbach
Manager, Air Permits Program

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Section 1. Permit Terms and Conditions

1. **Emission Units (EU) Authorization.** Emission units listed in Table 1 have specific monitoring, record keeping, or reporting conditions in this permit. Except as noted elsewhere in the permit, the information in Table 1 is for information purposes only. The specific unit description do not restrict the Permittee from replacing an emission unit identified in Table 1. The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing an emission unit, including any applicable minor or construction permit requirements.

Table 1 - Minor Permit Emission Unit Inventory

No.	Type	Make/Model	Fuel	Rating/Size
21	Reciprocating Internal Combustion Engine	MTU Detroit 16V 2000G45TB	Diesel	800 kWe

Section 2. Emission Fees

2. Condition 14 of Minor Permit AQ0075MSS02 dated March 26, 2008 is rescinded and replaced with the following:

34.1 the stationary source's assessable potential to emit of 1,320 TPY; or

Section 3. Owner Requested Limit to Avoid Project Classification as a PSD Major Modification

3. The Permittee shall limit operation of EU 22 to no more than 200 hours per 12 consecutive month period to avoid project classification as PSD Modification for NOx.

4. Monitor, Record and Report as follows:

4.1 Equip EU 22with a non-resettable, dedicated engine hour meter.

4.2 Monitor and record the monthly hours of operation of Emission Unit 22.

4.3 Before the end of each calendar month, calculate and record the total hours of operation for EU 22 for the previous month, then calculate the 12 month rolling total hours of operation by adding to the previous 11 months.

4.4 Notify the Department under Excess Emissions and Permit Deviations described in the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50, should the consecutive 12-month operating hours exceed the limit in this condition.

4.5 Report in the operating report submitted under the applicable operating report issued for the source under AS 46 14.130(b) and 18 AAC 50, the operating hours for EU 22 for each 12-month rolling period as recorded in Condition 4.3, for the period covered under the operating report.

Section 4. General Recordkeeping Requirements

5. **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 emission 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.

   5.1 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 5.1a that the person accepts or agrees to be bound by an electronic record executed or adopted with that signature.

6. **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 and 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.

Section 5. Standard Conditions

7. 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

    a. An enforcement action; or

    b. Permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280.

8. 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.

9. 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.

10. The permit may be modified, reopened, revoked and reissued, or terminated for cause. A request by the Permittee for modification, revocation and re-issuance, or termination or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

11. The permit does not convey any property rights of any sort, nor any exclusive privilege.

Section 6. Permit Documentation

September 13, 2010	Received comments to preliminary Minor Permit AQ0075MSS03 for TAPS PS4 via email from Don Mark Anthony (APSC) addressed to Jimmy Yap (ADEC).
June 2, 2010	Received response to incompleteness finding for AQ0075MSS03 from John Baldridge (APSC) addressed to John Kuterbach (ADEC) with actual emission estimates, revised PTE calculations and corrected attachments.
May 10, 2010	Incompleteness Finding letter from ADEC to John Baldridge (APSC) with a list of incompleteness items in the permit application for PS4 dated April 1, 2010.
April 12, 2010	Minor permit application AQ0075MSS03 for APSC'S TAPS PS4 Blackstart generation project dated April 1, 2010.

F.7 Permit No. AQ0075TVP04

DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY OPERATING PERMIT

Permit No. AQ0075TVP04 Issue: Final - January 20, 2022

Expiration Date: January 20, 2027

The Alaska Department of Environmental Conservation, under the authority of AS 46.14 and 18 AAC 50, issues an operating permit to the Permittee, **Alyeska Pipeline Service Company**, for the operation of the **Pump Station 4 (PS-4)**.

This permit satisfies the obligation of the owner and operator to obtain an operating permit as set out in AS 46.14.130(b).

As set out in AS 46.14.120(c), the Permittee shall comply with the terms and conditions of this operating permit.

Citations listed herein are contained within the effective version of 18 AAC 50 at permit issuance. All federal regulation citations are from those sections adopted by reference in this version of regulation in 18 AAC 50.040 unless otherwise specified.

All stationary source-specific terms and conditions of Air Quality Control Permit-to-Operate No. 9572-AA009; Construction Permit Nos. 9872-AC024, 075CP01, AQ0075CPT02, and AQ0075CPT03; and Minor Permit Nos. AQ0075MSS02 and AQ0075MSS03 have been incorporated into this operating permit.

Upon effective date of this permit, Operating Permit No. AQ0075TVP03 expires.

This Operating Permit becomes effective February 19, 2022.

Aaron Simpson

for: James R. Plosay, Manager
Air Permits Program

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Abbreviations and Acronyms

AAC....................Alaska Administrative Code
ADEC ....Alaska Department of Environmental Conservation
Administrator......EPA and the Department.
APSC ....Alyeska Pipeline Service Company
AS.......................Alaska Statutes
ASTM ....American Society for Testing and Materials
BACT ....best available control technology
bHp ....brake horsepower
Btu/scf ....British thermal units per standard cubic feet
CAM...................Compliance Assurance Monitoring
CDX....................Central Data Exchange
CEDRI ....Compliance and Emissions Data Reporting Interface
C.F.R. ....Code of Federal Regulations
CAA or The Act .Clean Air Act
CO ....carbon monoxide
CO_2e ....CO_2-equivalent
Department ....Alaska Department of Environmental Conservation
dscf ....dry standard cubic foot
EPA ....US Environmental Protection Agency
EU.......................emissions unit
°F ....Degree Fahrenheit
GHG ....Greenhouse Gas
gr/dscf.................grain per dry standard cubic foot (1 pound = 7000 grains)
GPA ....Gas Producers Association
gph or gal/hr ....gallons per hour
H_2S......................Hydrogen Sulfide
HAPs ....hazardous air pollutants [as defined in AS 46.14.990]
Hp ....horsepower
ID........................emissions unit identification number
ISO......................International Standard Organization
kJ/kW-hr.............Kilojoules per kilowatt-hour
kPa ....kiloPascals
kW ....kilowatts
LAER..................lowest achievable emission rate
LHV....................Lower Heating Value
lb..........................Pounds
lb/MMBtu...........Pounds per million Btu
lb/MWh...............Pounds per megawatt-hour
lb/yr ....Pounds per year
MACT ....maximum achievable control technology [as defined in 40 C.F.R. 63]
MMBtu/hr...........million BTUs per hour
MMscf ....million standard cubic feet
MR&R ....monitoring, recordkeeping, and
MMscf ....million standard cubic feet
MR&R ....monitoring, recordkeeping, and reporting
NAICS.................North American Industrial Classification System
NESHAPs ....National Emission Standards for Hazardous Air Pollutants [as contained in 40 C.F.R. 61 and 63]
NH_3 ....ammonia
NO_X.....................nitrogen oxides
NSPS ....New Source Performance Standards [as contained in 40 C.F.R. 60]
O & M ....operation and maintenance
O_2 ....oxygen
PAL ....plantwide applicability limitation
Pb ....lead
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
RICE ....Reciprocating Internal Combustion Engine
scf.........................standard cubic feet
SIC. ....Standard Industrial Classification
SIP........................State Implementation Plan
SPC ....Standard Permit Condition or Standard Operating Permit Condition
SO_2 ....sulfur dioxide
TAPS....................Tans-Alaska Pipeline System
tph ....tons per hour
TPY ....tons per year
VOC ....volatile organic compound [as defined in 40 C.F.R. 51.100(s)]
VOL ....volatile organic liquid [as defined in 40 C.F.R. 60.111b, Subpart Kb]
vol% ....volume percent
wt% ....weight percent
$wt\%S_{fuel}$ ....weight percent of sulfur in fuel

Section 1. Stationary Source Information

Identification

Permittee:		**Alyeska Pipeline Service Company** P. O. Box 196660 Anchorage, AK 99519-6660
Stationary Source Name:		**Pump Station 4 (PS-4)**
Location:		Latitude 68.4221º North; Longitude 149.3589º West
Physical Address:		Sections 5 and 8, T12S, R12E, Umiat Meridian, 155 miles south of Prudhoe Bay, AK
Owner:		Harvest Alaska, LLC ConocoPhillips Transportation (Alaska), Inc. ExxonMobil Pipeline Company
Operator:		**Alyeska Pipeline Service Company** P. O. Box 196660 Anchorage, AK 99519-6660
Permittee's Responsible Official:		Hillary Schaefer, Pipeline Director Alyeska Pipeline Service Company P. O. Box 60469, MS830 Fairbanks, AK 99706 Phone: 907-450-7746 Email: Hillary.Schaefer@alayeska-pipeline.com
Designated Agent:		CT Corporation 9360 Glacier Highway, Suite 202 Juneau, AK 99801
Stationary Source and Building Contact:		Mark Dahl/Tim Jones, Maintenance Supervisors PS-3 and PS-4 APSC, P. O. Box 196660, MS 507 Anchorage, AK 99519-6660 (907) 787-4402
Fee Contact:		Cindy Keuler, Environmental Program Coordinator Alyeska Pipeline Service Company P. O. Box 196660, MS 507 Anchorage, AK 99519-6660 (907) 787-8975, Email: Cindy.Keuler@alyeska-pipeline.com
Permit Contact:		Don Mark Anthony, Air Quality SME APSC, P. O. Box 196660, MS 507 Anchorage, AK 99519-6660 (907) 787-8568, Email: markanthonydt@alyeska-pipeline.com
Process Description:	SIC Code	4612 – Crude Petroleum Pipelines
	NAICS Code:	486110 – Pipeline Transportation of Crude Oil

[18 AAC 50.040(j)(3) & 50.326(a)]
[40 C.F.R. 71.5(c)(1) & (2)]

Section 2. Emissions Unit Inventory and Description

Emissions units listed in Table A have specific monitoring, recordkeeping, or reporting conditions in this permit. Emissions unit descriptions and ratings are given for identification purposes only, unless noted elsewhere in the permit.

Table A - Emissions Unit Inventory[1]

EU ID	Tag No.	Emission Unit Description	Fuel	Rating/Size	Commence Construction[2]
8[1]	34-H-1A	Eclipse Therminol Heater, 1000-5 HCLT Design	Natural Gas/ Diesel	20.6 MMBtu/hr	Pre-1980
9[1]	34-H-1B	Eclipse Therminol Heater, 1000-5 HCLT Design	Natural Gas/ Diesel	20.6 MMBtu/hr	Pre-1980
10[3]	34-FP-2PK	Detroit Diesel 6-71 Firewater Pump	Diesel	190 hp	Pre-1980
12	34-PK-3701R	Siemens Cyclone Turbine Electric Generator, PK Model #SGT-400	Natural Gas/ Diesel	12.9 MW ISO[4]	2005[5]
13	34-PK-3601R	Siemens Cyclone Turbine Electric Generator, PK Model #SGT-400	Natural Gas	12.9 MW ISO[4]	2005[5]
14	34-GEN-3801R	Caterpillar 3516B Engine Electric Generator	Diesel	2,250 kW	2005[5]
15[3]	34-GEN-4605R	UPS Electric Generator, PK Model #PPJD65MOD-1	Diesel	65 kWe	2005[5]
18[3]	N/A	11 Miscellaneous Shop Heaters	Natural Gas	3.28 MMBtu/hr, combined	2009[5]
21	TK-140	Breakout Tank 140	N/A	55,000 bbl	Pre-1978
22	34-GEN-4401	MTU Detroit 16V 2000G45TB	Diesel	800 kWe	2010

Notes:

1. The stationary source is now operating under strategic reconfiguration. EU IDs 1 – 7 have been decommissioned and the MR&R requirements applicable to these units have been deleted from the permit.
2. Commence construction is defined by 40 C.F.R. 52.21(b) & (i) and 40 C.F.R. 60.2.
3. EU IDs 10, 15 and 18 have potential emissions less than the significant thresholds under 18 AAC 50.326(e) & (g) but cannot be insignificant per 18 AAC 50.326(d)(1)(A) & (B).
4. International Standards Organization (ISO) standard day conditions means 288 degrees Kelvin, 60 percent humidity, and 101.3 kilopascals pressure, as described in 40 C.F.R. 60.331.
5. Construction dates represent when on-site installation activities commenced. The dates do not necessarily reflect the equipment manufacture dates since several of the units were purchased in completed form.

[18 AAC 50.326(a)]
[40 C.F.R. 71.5(c)(3)]

Section 3. State Requirements

Visible Emissions Standard

1. **Industrial Process and Fuel-Burning Equipment Visible Emissions.** The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from EU IDs 8 – 10, 12 – 15, 18, and 22 listed in Table A to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.

[18 AAC 50.040(j)(4), 50.055(a)(1), 50.326(j)(3), & 50.346(c)]
[40 C.F.R. 71.6(a)(1)]

1.1. For EU IDs 15 and 22, as long as the emissions units do not exceed the limits in Table B (EU ID 15) and Condition 23.2 (EU ID 22), monitoring shall consist of an annual compliance certification under Condition 80 for the visible emissions standard based on reasonable inquiry. Otherwise comply with Condition 1.2.

1.2. For EU IDs 10 and 14, as long as actual emissions from the emissions unit are less than the significant emissions thresholds listed in 18 AAC 50.326(e) during any consecutive 12-month period, monitoring shall consist of an annual compliance certification under Condition 80 for the visible emissions standard based on reasonable inquiry. The Permittee shall report in the operating report under Condition 79 if any of EU IDs 10, 14, 15, and 22 reaches any of the significant emissions thresholds listed in 18 AAC 50.326(e) and monitor, record, and report in accordance with Conditions 2 through 4 for the remainder of the permit term for that emissions unit.

1.3. For EU ID 18, monitoring shall consist of an annual compliance certification under Condition 80 for the visible emissions standard based on reasonable inquiry.

1.4. For EU IDs 8, 9, and 12 burn gas as the primary fuel. Monitoring for this emissions unit shall consist of a statement in each operating report under Condition 79 indicating whether this emissions unit burned gas as the primary fuel during the period covered by the report. If the emissions unit operated on a back-up liquid fuel during the period covered by the report, the Permittee shall monitor, record, and report in accordance with Condition 12.

1.5. For EU ID 13, burn only gas as fuel. Monitoring for this emissions unit shall consist of a statement in each operating report under Condition 79 indicating whether this emissions unit burned only gas during the period covered by the report. Report under Condition 78 if any fuel other than gas is burned.

[18 AAC 50.040(j)(4), 50.326(j)(3) & (4), & 50.346(c)]
[40 C.F.R. 71.6(a)(3) & (c)(6)]

Visible Emissions Monitoring, Recordkeeping, and Reporting (MR&R)

Liquid Fuel-Burning Equipment, EU IDs 10, 14, 15, and 22

2. **Visible Emissions Monitoring.** When required by any of Conditions 1.1 or 1.2, or in the event of replacement[1] during the permit term, the Permittee shall observe the exhaust of EU IDs 10, 14, 15, and 22 for visible emissions using the Method 9 Plan under Condition 2.1.

2.1. The Permittee may for each unit elect each unit elect to continue the visible emissions monitoring schedule specified in Conditions 2.2.b through 2.2.e that remains in effect from a previous permit.

2.2. **Method 9 Plan.** For all observations in this plan, observe emissions unit exhaust, following 40 C.F.R. 60, Appendix A-4, Method 9 for 18 minutes to obtain 72 consecutive 15-second opacity observations.[2]

a. First Method 9 Observation. Observe the exhausts of EU IDs 10, 14, 15, and 22 according to the following criteria:

(i) For any unit replaced, observe exhaust within 60 days of the newly installed emissions unit becoming fully operational.[3] Except as provided in Condition 2.2.e, after the First Method 9 observation:

(ii) For each of EU IDs 10, 14, 15, and 22, observe the exhaust of the emissions unit within 30 days after the end of the calendar month during which monitoring was triggered under Condition 1.2; or for an emissions unit with intermittent operations, within the first 30 days during the unit's next scheduled operation.

b. Monthly Method 9 Observations. After the first Method 9 observation conducted under Condition 2.2.a, perform observations at least once in each calendar month that the emissions unit operates.

c. Semiannual Method 9 Observations. After at least three monthly observations under Condition 2.2.b, unless a six-consecutive-minute average opacity is greater than 15 percent and one or more individual observations are greater than 20 percent, perform semiannual observations

(i) no later than seven months, but not earlier than five months, after the preceding observation; or

(ii) for an emissions unit with intermittent operations, during the next scheduled operation immediately following seven months after the preceding observation.

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1 *"Replacement,"* as defined in 40 C.F.R. 51.166(b)(32).
2 Visible emissions observations are not required during emergency operations.
3 "*Fully operational*" means upon completion of all functionality checks and commissioning after unit installation. "*Installation*" is complete when the unit is ready for functionality checks to begin.

d. Annual Method 9 Observations. After at least two semiannual observations under Condition 2.2.c, unless a six-consecutive-minute average opacity is greater than 15 percent and one or more individual observations are greater than 20 percent, perform annual observations

(i) no later than 12 months, but not earlier than 10 months, after the preceding observation; or

(ii) for an emissions unit with intermittent operations, during the next scheduled operation immediately following 14 months after the preceding observation.

e. Increased Method 9 Frequency. If a six-consecutive-minute average opacity is observed during the most recent set of observations to be greater than 15 percent and one or more individual observations are greater than 20 percent, then increase or maintain the observation frequency for that emissions unit to at least monthly intervals as described in Condition 2.2.b, and continue monitoring in accordance with the Method 9 Plan.

[18 AAC 50.040(j)(4), 50.326(j)(3), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(i)]

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

3.1. For all Method 9 observations,

a. the observer shall record the following:

(i) the name of the stationary source, emissions unit and location, emissions unit type, observer's name and affiliation, and the date on the Visible Emissions Observation Form in Section 12;

(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 or best estimate, if unknown) 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 Visible Emission Observation Form in Section 12, and

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

b. To determine the six-minute average opacity,

(i) divide the observations recorded on the record sheet into sets of 24 consecutive observations;

(ii) sets need not be consecutive in time and in no case shall two sets overlap;

(iii) for each set of 24 observations, calculate the average by summing the opacity of the 24 observations and dividing this sum by 24; and

(iv) record the average opacity on the sheet.

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

3.2. The records required by Condition 3.1 may be kept in electronic format.

[18 AAC 50.040(j)(4), 50.326(j)(3) & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(ii)]

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

4.1. Include in each operating report required under Condition 79 for the period covered by the report:

a. for all Method 9 Plan observations:

(i) copies of the observation results (i.e. opacity observations) for each emissions unit, except for the observations the Permittee has already supplied to the Department; and

(ii) a summary to include:

(A) number of days observations were made;

(B) highest six-consecutive- and 18-consecutive-minute average opacities observed; and

(C) dates when one or more observed six-consecutive-minute average opacities were greater than 20 percent;

b. a summary of any monitoring or recordkeeping required under Conditions 2 and 3 that was not done.

4.2. Report under Condition 78:

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

b. if any monitoring under Condition 2 was not performed when required, report within three days of the date the monitoring was required.

[18 AAC 50.040(j)(4), 50.326(j)(3), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(iii)]

Particulate Matter (PM) Emissions Standard

5. **Industrial Process and Fuel-Burning Equipment PM Emissions.** The Permittee shall not cause or allow particulate matter emitted from EU IDs 8 – 10, 12 – 15, 18, and 22 listed in Table A to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.

[18 AAC 50.040(j)(4), 50.055(b)(1), 50.326(j)(3), & 50.346(c)]
[40 C.F.R. 71.6(a)(1)]

5.1. For EU IDs 15 and 22, as long as the emissions units do not exceed the limits in Table B (EU ID 15) and Condition 23.2 (EU ID 22), monitoring shall consist of an annual compliance certification under Condition 80 for the PM emissions standard based on reasonable inquiry. Otherwise, comply with Condition 5.2.

5.2. For EU IDs 10 and 14, as long as actual emissions from the emissions unit are less than the significant emissions thresholds listed in 18 AAC 50.326(e) during any consecutive 12-month period, monitoring shall consist of an annual compliance certification under Condition 80 for the PM emissions standard based on reasonable inquiry. The Permittee shall report in the operating report under Condition 79 if any of EU IDs 10, 14, 15, and 22 reaches any of the significant emissions thresholds and monitor, record and report in accordance with Conditions 6 through 8 for the remainder of the permit term for that emissions unit.

5.3. For EU ID 18, the Permittee must annually certify compliance under Condition 80 for the PM emissions standard based on reasonable inquiry.

5.4. For EU ID 8, 9, and 12, the Permittee shall comply with Condition 1.4.

5.5. For EU ID 13, the Permittee shall comply with Condition 1.5.

[18 AAC 50.040(j)(4), 50.326(j)(3), & 50.346(c)]
[40 C.F.R. 71.6(a)(3) & (c)(6)]

PM MR&R

Liquid Fuel-burning Engines and Turbines (EU IDs 10, 12, 14, 15, and 22)

6. **PM Monitoring.** The Permittee shall conduct source tests on EU IDs 10, 14, 15, and 22 (when required by Condition 5.2), to determine the concentration of PM in the exhaust of each emissions unit as follows:

[18 AAC 50.040(j)(4), 50.326(j)(3), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(i)]

6.1. If the result of any Method 9 observation conducted under Condition 2.1 for any of EU IDs 10, 14, 15, and 22 is greater than the criteria of Condition 6.2.a or Condition 6.2.b, or if the Method 9 observation conducted under Condition 12.3 for EU ID 12 exceeds the standard in Condition 1, the Permittee shall, within six months of that Method 9 observation, either:

a. take corrective action and observe the emissions unit exhaust under load conditions comparable to those when the criteria were exceeded, following 40 C.F.R. 60, Appendix A-4 Method 9 for 18 minutes to obtain 72 consecutive 15-second opacity observations, to show that emissions are no longer greater than the criteria of Condition 6.2; or

b. except as exempted in Condition 6.4, conduct a PM source test according to requirements set out in Section 6.

6.2. Take corrective action or conduct a PM source test, in accordance with Condition 6.1, if any Method 9 observation under Condition 2.1 results in an 18-minute average opacity greater than

a. 20 percent for an emissions unit with an exhaust stack diameter that is equal to or greater than 18 inches; or

b. 15 percent for an emissions unit with an exhaust stack diameter that is less than 18 inches, unless the Department has waived this requirement in writing.

6.3. During each one-hour PM source test run under Condition 6.1.b, observe the emissions unit exhaust for 60 minutes in accordance with Method 9 and calculate the highest 18-consecutive-minute average opacity measured during each one-hour test run. Submit a copy of these observations with the source test report.

6.4. The PM source test requirements in Conditions 6.1.b are waived for an emissions unit if

a. a PM source test on that unit has shown compliance with the PM standard during this permit term; or

b. corrective action was taken to reduce visible emissions and two consecutive 18-minute Method 9 visible emissions observations (as described in Condition 2.1) conducted thereafter within a six-month period show visible emissions less than the threshold in Condition 6.2.

7. **PM Recordkeeping.** The Permittee shall comply with the following:

7.1. Keep records of the results of any source test and visible emissions observations conducted under Condition 6.

[18 AAC 50.040(j)(4), 50.326(j)(3), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(ii)]

8. **PM Reporting.** The Permittee shall report as follows:

8.1. Notify the Department of any Method 9 observation results that are greater than the threshold of either Condition 6.2.a or Condition 6.2.b within 30 days of the end of the month in which the observations occurred. Include the dates, EU IDs, and results when an observed 18-minute average opacity was greater than an applicable threshold in Condition 6.2.

8.2. In each operating report under Condition 79, include:

a. a summary of the results of any PM source test and visible emissions observations conducted under Condition 6; and

b. copies of any visible emissions observation results greater than the thresholds of Condition 6.2, if they were not already submitted.

8.3. Report in accordance with Condition 78

a. anytime the results of a PM source test exceed the PM emissions standard in Condition 5; or

b. if the requirements under Condition 6.1 were triggered and the Permittee did not comply on time with either Condition 6.1.a or 6.1.b. Report the deviation within 24 hours of the date compliance with Condition 6.1 was required.

[18 AAC 50.040(j)(4), 50.326(j)(3), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(iii)]

Liquid Fuel-Burning Boilers and Heaters (EU IDs 8 and 9)

9. PM Monitoring. The Permittee shall conduct source tests to determine the concentration of PM in the exhaust of each emissions unit as follows:

9.1. If the result of any Method 9 observation conducted under Condition 12.3 for any of EU IDs 8 and 9 results in an 18-minute average opacity greater than 20 percent opacity, the Permittee shall, within six months of that Method 9 observation, either:

a. take corrective action and observe the emissions unit exhaust under load conditions comparable to those when the criteria were exceeded, following 40 C.F.R. 60, Appendix A-4 Method 9 for 18 minutes to obtain 72 consecutive 15-second opacity observations, to show that emissions are no longer greater than an 18-minute average opacity of 20 percent; or

b. except as exempted under Condition 9.3, conduct a PM source test according to the requirements in Section 6.

9.2. During each one-hour PM source test run under Condition 9.1, observe the emissions unit exhaust for 60 minutes in accordance with Method 9 and calculate the highest 18-consecutive-minute average opacity measured during each one-hour test run. Submit a copy of these observations with the source test report.

9.3. The PM source test requirement in Condition 9.1 is waived for an emissions unit if:

a. a source test on that unit has shown compliance with the PM standard during the permit term; or

b. corrective action was taken to reduce visible emissions and two consecutive 18-minute Method 9 visible emissions observations (as described in Condition 2.1) conducted thereafter within a six-month period show visible emissions less than the threshold in Condition 9.1.

[18 AAC 50.040(j)(4), 50.326(j)(3), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(i)]

10. PM Recordkeeping. The Permittee shall keep records of the results of any source test and visible emissions observations conducted under Condition 9.

[18 AAC 50.040(j)(4), 50.326(j)(3), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(ii)]

11. PM Reporting. The Permittee shall report as follows:

11.1. Notify the Department of any Method 9 observation results that are greater than the threshold of Condition 9.1 within 30 days of the end of the month in which the observations occurred. Include the dates, EU IDs, and results when an observed 18-minute average opacity was greater than the threshold in Condition 9.1.

11.2. In each operating report required by Condition 79, include:

a. a summary of the results of any source test and visible emissions observations conducted under Condition 9; and

b. copies of any visible emissions observation results greater than the threshold in Condition 9.1, if they were not already submitted.

11.3. Report in accordance with Condition 78 any time the results of a source test exceed the PM emission standard in Condition 5.

[18 AAC 50.040(j)(4), 50.326(j)(3), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(iii)]

Visible Emissions & PM MR&R

Dual Fuel-Burning Emissions Units (EU ID 8, 9, and 12)

12. The Permittee shall monitor, record, and report the monthly hours of operation when operating on a back-up liquid fuel.

12.1. For any of EU IDs 8, 9, and 12 that does not exceed 400 hours of operations per calendar year on a back-up liquid fuel, monitoring of compliance for visible emissions and PM shall consist of an annual certification under Condition 80 based on reasonable inquiry.

12.2. For any of EU IDs 8, 9, and 12, notify the Department and begin monitoring the affected emissions unit in accordance with Condition 12.3 no later than 15 days after the end of a calendar month in which the cumulative hours of operation for the calendar year exceed any multiple of 400 hours on a back-up liquid fuel; or for an emissions unit with intermittent back-up fuel use, during the next scheduled operation on back-up liquid fuel.

12.3. When required to do so by Condition 12.2, observe the emissions unit exhaust, following 40 C.F.R. 60, Appendix A-4 Method 9, for 18 minutes to obtain 72 consecutive 15-second opacity observations.

a. If the observation exceeds the standard in Condition 1, monitor as described in Condition 6 for EU ID 12 or Condition 9 for EU IDs 8 and 9.

b. If the observation does not exceed the standard in Condition 1, no additional monitoring is required until the cumulative hours of operation exceed each subsequent multiple of 400 hours on back-up liquid fuel during a calendar year[4].

12.4. Keep records and report in accordance with Conditions 7 and 8 for EU ID 12 or Conditions 10 and 11 for EU IDs 8 and 9.

12.5. Report under Condition 78 if the Permittee fails to comply with Conditions 12.2, 12.3, or 12.4.

[18 AAC 50.040(j)(4), 50.326(j)(3), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(i) – (iii)]

Sulfur Compound Emissions Standard

13. Sulfur Compound Emissions. The Permittee shall not cause or allow sulfur compound emissions, expressed as SO_2, from EU IDs 8 – 10, 12 – 15, 18, and 22 to exceed 500 ppm averaged over three hours.

[18 AAC 50.040(j)(4), 50.055(c), 50.326(j)(3), & 50.346(c)]
[40 C.F.R. 71.6(a)(1)]

Sulfur Compound MR&R

Fuel Oil[5] (EU IDs 8 – 10, 12, 14, 15, and 22)

14. Sulfur Compound Monitoring, Recordkeeping, and Reporting. The Permittee shall monitor, record, and report sulfur content in fuel oil according to Condition 19.2.

[18 AAC 50.040(j)(4), 50.326(j)(3), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(i) & (ii)]

Fuel Gas (EU IDs 8, 9, 12, 13, 18)

15. Sulfur Compound Monitoring Recordkeeping, and Reporting. The Permittee shall monitor, record, and report sulfur content in fuel gas according to Condition 19.1.

[18 AAC 50.040(j)(4) & 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3) & (c)(6)]

Preconstruction Permit [6] Requirements

Owner Requested Limits to Avoid PSD Modification and Protect Ambient Air Quality

[4] If the requirement to monitor is triggered more than once in a calendar month, only one Method-9 observation is required to be conducted by the stated deadline for that month.

[5] *Oil* means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil, as defined in 40 C.F.R. 60.41b, effective 7/1/07.

[6] *Preconstruction Permit* refers to federal PSD permits, state-issued permits-to-operate issued on or before January 17, 1997 (these permits cover both construction and operations), construction permits issued on or after January 18, 1997, and minor permits issued on or after October 1, 2004.

16. Eclipse Heaters (EU IDs 8 & 9) Fuel Consumption and Operational Hour Limits.

16.1. The Permittee shall not allow the fuel usage and operating time for EU IDs 8 and 9 to exceed:

a. 1,000 hours for any consecutive 12-month period on liquid fuel, combined total, or

b. 159,000 gallons for any consecutive 12-month period on liquid fuel, combined total, whichever is less.

[Permit to Operate No. 9572-AA009 Amendment No. 2, 12/4/98]

16.2. Keep records of fuel consumption and operating hours. The fuel consumption may be estimated from firing time and maximum fuel oil firing rate in gal/hr.

16.3. Report under Condition 78:

a. the total combined hours of operation on liquid fuel per rolling 12-month period for each month of the reporting period, and

b. the total combined liquid fuel consumption per rolling 12-month period for each month of the reporting period.

16.4. Report under Condition 78 when the fuel or operational hour limits of Condition 16 are exceeded.

16.5. Conditions 16 through 16.5 will no longer apply upon decommissioning of EU IDs 8 and 9 in accordance with Condition 18.2.

[18 AAC 50.040(j); 18 AAC 50.326(j)]
[40 C.F.R. 71.6(a)(3) & (c)(6)]

Owner Requested Limits to Avoid Classification as a HAP Major

17. Tank 140 (EU ID 21) Owner Requested Limits (ORLs). To avoid classification as a Hazardous Air Pollutant (HAP) Major Stationary Source under 18 AAC 50.316, the Permittee shall limit the HAP emissions from the crude oil breakout tank, Tank 140 (EU ID 21), to no more than 8.0 tons per 12-month rolling period for any individual HAP and 16.9 tons per 12-month rolling period for the aggregate total of HAPs.

17.1. Monitoring and Recordkeeping. The Permittee shall monitor compliance with Condition 17 as follows:

a. Sample the discharge crude stream at PS-1 once every 12 calendar months[7].

(i) Sampling under Conditions 17.1.a is not required if the Permittee is satisfying the crude oil sampling requirements for HAP ORLs at another TAPS pump station.

[7] The Permittee has satisfied the quarterly and semi-annual sampling requirements of Construction Permit No. AQ0075CPT03.

b. Determine the amounts of 1,3 butadiene, N-hexane, benzene, 2,2,4 trimethylpentane, toluene, ethyl benzene, xylenes, isopropyl benzene, and naphthalene in the crude oil using ASTM Method D-5134M.

c. Determine the flow rate data of the crude oil routed to EU ID 21.

(i) Monitor and record tank level changes at least once per hour.

(ii) Monitor and calculate the monthly total volume of crude oil routed to EU ID 21 using tank level change indicators.

(iii) For any period during which crude oil flow data is unavailable under Condition 17.1.c, the Permittee shall estimate the flow rate of crude oil to EU ID 21 using a crude oil flow rate of 1,675,000 barrels per year (bbl/yr), prorated over the time period during which no data is available.[8]

d. Calculate the 12-month rolling total HAP emissions from EU ID 21 for each month as follows:

(i) Use the most recent crude composition analysis in Condition 17.1.b, and the total volume of crude oil routed to EU ID 21 for the month determined from Conditions 17.1.c(ii) or 17.1.c(iii).

(ii) Use the methodology presented in the Permittee's October, 2003 permit application as described in Section 11.

(iii) Perform and record the calculations for the six calendar months at the time the semi-annual operating reports are due under Condition 79 for the six calendar months covered in the operating report.

(iv) If the most recent calculations under Condition 17.1.d(iii) show HAP emissions exceed 50 percent of either limit under Condition 17, for any 12-month rolling period, perform and record the calculations for each calendar month no later than 30 days after the end of the month.

(v) After performing six months of calculations under Condition 17.1.d(iv) and showing HAP emissions less than 50 percent of each limit in Condition 17, the Permittee shall perform calculations semi-annually at the time the operating reports are due.

e. If the calculated HAP emissions under Condition 17.1.d exceed 90 percent of either of the limits in Condition 17,

[8] The pro-ration calculation for periods when no data is available does not apply to periods when the tank is drained and isolated.

(i) Within four months of discovery, initiate and complete a validation demonstration of predicting crude vapor HAP content from crude oil sampling by comparing HAP emissions derived using Gas Producers Association Method 2286 on the headspace of any one of the breakout tanks at Pump Stations (PS) 3, 4, 5, 7 or 9 to calculations based on sampling of PS-1 crude discharge stream;

(ii) For headspace sampling, take four samples of the tank headspace, consecutively, and if possible take all on the same day;

(iii) For crude oil sampling, take at least two crude oil discharge samples at PS-1, within 15 days of headspace sampling; and

(iv) Use the average results of the sampling conducted under Conditions 17.1.e(ii) and 17.1.e(iii), to compare the calculated HAP emissions using crude oil discharge analysis to those using the in-tank headspace analysis carried out concurrently.

(A) If the crude oil analysis methodology predicts higher emissions than the headspace sampling, sample crude oil once every 12 calendar months and calculate the HAP emissions according to Condition 17.1.d;

(B) If the crude oil analysis methodology predicts lower emissions than the headspace sampling, calculate HAP emissions by sampling at quarterly intervals and calculate according to Condition 17.1.d and multiply all results by the ratio between test results from Conditions 17.1.e(ii) and 17.1.e(iii). When HAP emissions fall below 90 percent, the Permittee may reduce sampling frequency to once every 12 calendar months and calculate HAP emissions according to Condition 17.1.d. The Permittee shall continue to multiply the results by the ratio determined between test results from Conditions 17.1.e(ii) and 17.1.e(iii).

17.2. Reporting. The Permittee shall report as follows:

a. Report under the operating report in Condition 79 the following information:

(i) the results of any crude oil sample analysis obtained under Condition 17.1.b during the reporting period; and

(ii) the completed calculation spreadsheets showing the 12-month rolling total HAP emissions for each pollutant and the 12-month rolling aggregate total HAP emissions as calculated under Conditions 17.1.d and 17.1.e.[9]

[9] Corrected the material mistake in Permit No. AQ0075CPT03 for the cross-referenced condition, from Condition 17.1.d(i) to Condition 17.1.e.

b. Report under excess emission and permit deviation reports in Condition 78, if:

(i) the 12-month rolling total individual HAP emissions from EU ID 21 exceeds the limit in Condition 17;

(ii) the 12-month rolling total aggregate HAP emissions from EU ID 21 exceeds the limit in Condition 17; or

(iii) the monitoring, recordkeeping, or reporting requirements are not in accordance with Conditions 17.1.a through 17.1.e(iv).[9]

[Construction Permit No. AQ0075CPT03, 10/28/05]
[18 AAC 50.040(j); 18 AAC 50.326(j)]
[40 C.F.R. 71.6(a)]

Installation Authorization and Startup Notification Requirements under Strategic Reconfiguration

18. The Permittee may install EU IDs 12 – 15, and 18 described in Table A at this stationary source. The Permittee shall configure EU IDs 12 and 13 with Dry Low Emissions (DLE) Technology.

18.1. At least 5 days before initial startup[10] of EU IDs 18 (or replacement units), submit the following to the Department's Fairbanks office:

a. vendor specification sheets that identify the unit type, make and model (including model number), serial number and rating/size; and

b. the installation date and estimated date of startup.

18.2. Unless an extension is granted by the Department in writing as indicated in Condition 18.3, decommission[11] existing EU IDs 8 and 9 listed in 18.3 within 270 calendar days[12] after initial startup of EU 18 (or replacement units).

18.3. The Department may allow an extension of the "initial startup period" for due cause. Submit a request for an extension in writing to the Department's Fairbanks office within 240 days of initial startup of EU ID 18 (or replacement units). Include a description of the reason for the extension. The Department will grant an extension of up to 90 days if the Department finds due cause exists.

18.4. Include the following information with the next operating report described in Condition 79:

a. the actual initial startup date for EU ID 18, or any replacement unit (unless previously submitted);

b. the decommissioning dates for each EU IDs 8 and 9; and

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[10] *Initial startup* means when an emission unit is first fired.

[11] *Decommission* means the fuel systems and generator electrical leads have been disconnected.

[12] The initial startup period lasts 270 days after initial startup.

c. copies of the notifications and records required by Condition 18.1.

[Minor Permit No. AQ0075MSS02, 3/26/08]
[18 AAC 50.040(j); 18 AAC 50.326(j)]
[40 C.F.R. 71.6(a)]

Ambient Air Quality Protection Requirements

19. Fuel Sulfur Limits. For EU IDs 8 – 10, 12 – 15, 18, and 22, the Permittee shall comply with SO_2 ambient air quality standards and increments as follows:

19.1. For EU IDs 8, 9, 12, 13, 18, the Permittee shall limit the hydrogen sulfide (H_2S) concentration of fuel gas to no greater than 150 parts per million by volume (ppmv).

[Permit No. AQ0075CPT02, 2/14/05]

a. The Permittee shall obtain a statement from the fuel supplier no less than once every three months, of the fuel gas H_2S concentration in ppm; or

b. Conduct tests no less than once every three months and on each change in the supply of gas to determine the fuel gas H_2S concentration.

(i) A representative sample can be taken anywhere along the fuel gas line.

(ii) Determine the H_2S concentration using either ASTM D4810, D4913, or GPA Standard 2377, or an appropriate method listed in 18 AAC 50.035(b)-(c) or 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1).

c. Keep records of the H_2S concentration of the fuel gas for all tests required under Condition 19.1.a or 19.1.b.

d. The Permittee shall report as follows:

(i) Report in each operating report required by Condition 79, the results of each H_2S concentration analysis of gaseous fuel obtained under Condition 19.1.a or 19.1.b.

(ii) Report as excess emissions and permit deviation, in accordance with Condition 78, whenever the H_2S concentration in the gaseous fuel obtained under Condition 19.1.a or 19.1.b exceeds the limit in Condition 19.1.

[40 C.F.R. 71.6(a)(3) & (c)(6)]

19.2. For EU IDs 8 – 10, 12, 14, 15, and 22, the Permittee shall limit the diesel fuel sulfur content to no greater than 0.20 percent by weight.

[Permit No. AQ0075CPT02, 2/14/05]

a. The Permittee shall do one of the following for each shipment of fuel:

(i) If the fuel grade requires a sulfur content of less than 0.2 percent by weight, keep receipts that specify the fuel grade and amount; or

(ii) If the fuel grade does not require a sulfur content of less than 0.2 percent by weight, keep receipts that specify fuel grade and amount and

(A) test a representative sample of the fuel from the stationary source fuel storage tank once per calendar month to determine the sulfur content; or

(B) obtain test results showing the sulfur content of the fuel from the supplier or refinery; the test results must include a statement signed by the supplier or refinery of what fuel they represent.

b. Fuel testing under Condition 19.2.a(ii) must follow an appropriate method listed in 18 AAC 50.035(b)-(c) or 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1).

c. Keep records of the sulfur content of each fuel delivery obtained under Condition 19.2.a(i) and the results of any fuel sulfur testing conducted under Condition 19.2.a(ii).

d. The Permittee shall report as follows:

(i) Report in each operating report required by Condition 79, a list of the fuel grades received at the stationary source during the reporting period. For any grade with a maximum fuel sulfur content greater than 0.2 percent by weight, the fuel sulfur content of each shipment of fuel.

(ii) Report as excess emissions and permit deviation, in accordance with Condition 78, whenever the sulfur content of a shipment of fuel or fuel in the stationary source's storage tank exceeds the limit in Condition 19.2.

[18 AAC 50.040(j), 18 AAC 50.326(j)]
[40 C.F.R. 71.6(a)(3) & (c)(6)]

20. **Operational Limits (NOx, SO_2).** The Permittee shall restrict the 12 consecutive month operating hours of EU IDs 12, 14, and 15 to less than the limits listed in Table B and shall comply with Conditions 20.1 through 20.4 to protect ambient air quality standards and increments.

Table B – Operating Hour Limits

EU ID	12-Consecutive Month Hourly Limit, in hours
12	240 on diesel fuel
14	600 total
15	300 total

[Minor Permit No. AQ0075MSS02, 3/26/08]

20.1. Monitor and record the hours of operation for each month.

a. that EU ID 12 operated on diesel fuel; and

b. the total hours of operation for each EU IDs 14 and 15.

[Minor Permit No. AQ0075MSS02, 3/26/08]

20.2. By the last day of each month, add the previous months' total to preceding 11 months to get the 12 consecutive months' total:

a. For EU ID 12 operated on diesel fuel; and

b. For each EU IDs 14 and 15.

20.3. Report as described in Condition 78 if the 12 12-month total operating hours exceeds the limit in Table B.

20.4. Include copies of records required under Conditions 20.1 and 20.2 with the operating report for that period as described in Condition 79.

[Permit No. AQ0075CPT02, 2/14/05]
[Minor Permit AQ0075MSS03, 09/30/10]
[18 AAC 50.040(j); 18 AAC 50.326(j)]
[40 C.F.R. 71.6(a)]

21. Stack Parameters. The Permittee shall maintain the exhaust stack for EU ID 12 to at least 51 feet above gravel pad elevation.

[Construction Permit No. AQ0075CPT02, 2/14/05]
[18 AAC 50.040(j), 50.326(j)]
[40 C.F.R. 71.6(a)]

ORLs to Avoid Project Classification as a PSD Modification

22. Carbon Monoxide (CO) Limit. For EU IDs 12 and 13, the Permittee shall

22.1. Comply with operating hour limits listed in Table B;

22.2. Use the following limits that are based on vendor data shown in Table C:

a. Limit operating hours (including diesel operating hours) at less than or equal to 50 percent load ($H_{\leq 50}$) to no more than 2,160 hours per 12 consecutive months; and

b. Limit operating hours (including diesel operating hours) at loads greater than 50 percent and less than or equal to 60 percent ($H_{50\text{-}60}$) as defined in Equation 1:

Equation 1[13] $$H_{50-60} = 10{,}177 - 3.9177(H_{\leq 50})$$

[13] From page 2-28 of the application dated August 2004. APSC developed this equation based on vendor data.

Where: $H_{\leq 50}$ = number of hours at less than or equal to 50 percent load (maximum 2,160); and

$H_{50\text{-}60}$ = number of hours at loads greater than 50 percent and less than or equal to 60 percent.

22.3. Ensure the hourly average[14] minimum intake temperature is above minus 20 degrees Fahrenheit (°F).

22.4. For each of EU IDs 12 and 13, record the hourly average turbine intake temperature (*T*) in °F for fuel gas and diesel fuel.

22.5. For each of EU IDs 12 and 13, using an hour meter, monitor and record the number of hours operated (including diesel operating hours) at less than or equal to 50 percent load, and at greater than 50 percent but less than or equal to 60 percent load, calculated as follows:

a. Measure and record the hourly average power output in kW;

b. For each hour, based on *T* recorded in Condition 22.4, calculate the maximum turbine load in kW for that hourly temperature as follows:[15]

(i) If *T* is less than or equal to minus 20°F:

$$L_{MAX} = 12{,}958$$

(ii) If *T* is between minus 20°F and plus 20°F:

$$L_{MAX} = 13{,}292 + 10.706T - 0.3105T^2$$

(iii) If *T* is above plus 20°F:

$$L_{MAX} = 14{,}548 - 55.97T$$

Where: L_{MAX} = Maximum turbine load in kW

T = Hourly temperature in °F

c. Calculate the hourly percent load by dividing the actual power output in kW recorded in Condition 22.5.a by the maximum load calculated in Condition 22.5.b.

22.6. Sample fuel gas heat content quarterly and calculate heat content (in MMBtu/lb[16]) in accordance with ASTM 3588.

22.7. No later than the last day of each month, calculate the number of hours in each tier for the previous month and add to the preceding 11 months to get the 12 month total.

[14] For the purposes of this permit, hourly average shall be calculated using a minimum of one data point every 15 minutes, excluding periods of startup not to exceed 10 minutes.

[15] Email from Don Mark Anthony, 2/10/05.

[16] Corrected the typographical error in Permit No. AQ0075CPT03 for the *pound* abbreviation, from *lbm* to *lb*.

22.8. Report as excess emissions and permit deviation as described in Condition 78, any time the

a. cumulative operating hours (including diesel operating hours) for EU IDs 12 and 13 exceed any limit in Conditions 22.1 and 22.2; and

b. hourly average turbine intake temperature is below the limit in Condition 22.3.

22.9. Report as described in Condition 79.

a. the monthly and 12 consecutive month:

(i) total operating hours at less than or equal to 50 percent load (Tier 3);

(ii) operating limit greater than 50 percent load and less than or equal to 60 percent load calculated using Equation 1; and

(iii) total operating hours greater than 50 percent load and less than or equal to 60 percent load (Tier 2);

b. the quarterly fuel heat content (Lower Heating Value).

c. the minimum hourly average turbine intake temperature for each month of the reporting period.

d. records sufficient for an inspector to verify compliance with Conditions 22.1 and 22.2.

Table C – CO Emission Rates for EU IDs 12 and 13 Burning Fuel Gas (ppmvd) and corrected to 15 percent Oxygen, Based on Vendor Data[1, 3]

Source Test Average Load (Percent)[2]	**Source Test Turbine Inlet Temperature, T, degrees Fahrenheit**								
	T ≥ 90	**80 ≤ T < 90**	**60 ≤ T < 80**	**40 ≤ T < 60**	**20 ≤ T < 40**	**0 ≤ T < 20**	**-10 ≤ T < 0**	**-20 ≤ T < -10**	**T< - 20**
	Summertime				Wintertime				
60 < Load (Tier 1)	60	60	60	60	60	60	60	60	60
50 < Load ≤ 60 (Tier 2)	30	30	60	60	575	575	1,450	1,562	1,562
Load ≤ 50 (Tier 3)	1,800	2,200	2,500	2,590	3,750	3,750	5,000	5,625	5,625

Notes:
(1) Emission rates in ppmvd are the emission rates used to develop the equation in Condition 22.2, as described in the application.
(2) Take into account the change in maximum load with temperature.
(3) Because the source test results are lower than the vendor data, the Permittee elects to use the more conservative vendor emission rates data provided in Table C until re-tested emission factors exceed these values.

[Permit No. AQ0075CPT02, 2/14/05]
[18 AAC 50.040(j), 18 AAC 50.326(j)]
[40 C.F.R. 71.6(a)]

23. Nitrogen Oxides (NOx) Limit. The Permittee shall

23.1. For EU IDs 12, 14, and 15:

a. Comply with operating hour limits, listed in Table B;

b. Calculate and record the 12 consecutive month total operating hours for EU ID 12 burning diesel using data obtained in Condition 20.1; and

c. Monitor, record, and report in accordance with Conditions 20.1 through 20.4.

[Permit No. AQ0075MSS02, 3/26/2008]
[18 AAC 50.040(j), 18 AAC 50.326(j)]
[40 C.F.R. 71.6(a) & (c)(6)]

23.2. For EU ID 22, limit the hours of operation to no more than 200 hours per 12 consecutive month period. Monitor, record, and report as follows:

a. Equip EU ID 22 with a non-resettable, dedicated engine hour meter.

b. Monitor and record the monthly hours of operation of EU ID 22.

c. Before the end of each calendar month, calculate and record the total hours of operation for EU ID 22 for the previous month, then calculate the 12 consecutive month total hours of operation by adding the monthly total to the previous 11 consecutive month total.

d. Report in the operating report described in Condition 79, the total hours of operation for EU ID 22 for each 12 consecutive month period, for each month covered by the report.

e. Report as excess emissions and permit deviation as described in Condition 78, any time the annual hours of operation for EU ID 22, recorded under Condition 23.2.c, exceed the limit in Condition 23.2; or if any of Conditions 23.2.a through 23.2.d are not met.

[Permit No. AQ0075MSS03, 9/30/10]
[18 AAC 50.040(j), 18 AAC 50.326(j)]
[40 C.F.R. 71.6(a) & (c)(6)]

24. Sulfur Dioxide (SO_2) Limit. The Permittee shall comply with operating hour limits for EU IDs 12, 14, and 15 listed in Table B, and fuel sulfur limits in Condition 19.

24.1. Monitor, record, and report in accordance with Conditions 19 and 20.

[Permit No. AQ0075CPT02, 2/14/05]
[18 AAC 50.040(j), 18 AAC 50.326(j)]
[40 C.F.R. 71.6(a) & (c)(6)]

Insignificant Emissions Units

25. For emissions units at the stationary source that are insignificant as defined in 18 AAC 50.326(d)-(i) that are not listed in this permit, the following apply:

25.1. **Visible Emissions Standard**: The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from an industrial process or fuel-burning equipment, or an incinerator to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.

[18 AAC 50.050(a) & 50.055(a)(1)]

25.2. **Particulate Matter Standard**: The Permittee shall not cause or allow particulate matter emitted from an industrial process or fuel-burning equipment to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.

[18 AAC 50.055(b)(1)]

25.3. **Sulfur Compound Standard**: The Permittee shall not cause or allow sulfur compound emissions, expressed as SO_2, from an industrial process or fuel-burning equipment, to exceed 500 ppm averaged over three hours.

[18 AAC 50.055(c)]

25.4. **General MR&R for Insignificant Emissions Units:** The Permittee shall comply with the following:

a. Submit the compliance certifications of Condition 80 based on reasonable inquiry;

b. Comply with the requirements of Condition 61;

c. Report in the operating report required by Condition 79 if an emissions unit has historically been classified as insignificant because of actual emissions less than the thresholds of 18 AAC 50.326(e) and current actual emissions have become greater than any of those thresholds; and

d. No other monitoring, recordkeeping or reporting is required for insignificant emissions units to demonstrate compliance with the emissions standards under Conditions 25.1, 25.2, and 25.3.

[18 AAC 50.040(j)(4), 50.326(j)(3), & 50.346(b)(4)]
[40 C.F.R. 71.6(a)(1) & (3)]

Section 4. Federal Requirements

40 C.F.R. Part 60 New Source Performance Standards (NSPS)

Subpart A – General Provisions

26. NSPS Subpart A Notification. For any affected facility[17] or existing facility[18] regulated under NSPS requirements in 40 C.F.R. 60, and required by the applicable subpart, the Permittee shall furnish the Department and EPA written or electronic notification of:

[18 AAC 50.035 & 50.040(a)(1)]
[40 C.F.R. 60.7(a) & 60.15(d), Subpart A]

26.1. the date construction or reconstruction of an affected facility commences postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in complete form;

[40 C.F.R. 60.7(a)(1), Subpart A]

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

[40 C.F.R. 60.7(a)(3), Subpart A]

26.3. 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.

[40 C.F.R. 60.7(a)(4), Subpart A]

26.4. any proposed replacement of components 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:

[40 C.F.R. 60.15(d), Subpart A]

a. the name and address of owner or operator,

b. the location of the existing facility,

[17] *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.

[18] *Existing facility* means, with reference to a stationary source, any apparatus of the type for which a standard is promulgated in 40 C.F.R. Part 60, 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.

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

g. a discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

27. 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 EU IDs 12 and 13 any malfunctions of associated air-pollution control equipment, or any periods during which a continuous monitoring system or monitoring device for EU IDs 12 and 13 is inoperative.

[18 AAC 50.040(a)(1)]
[40 C.F.R 71.6(a)(3)(ii)(B)]
[40 C.F.R. 60.7(b), Subpart A]

28. NSPS Subpart A Excess Emissions and Monitoring Systems Performance Report. The Permittee shall submit to the Department and to EPA "excess emissions and monitoring systems performance (EEMSP)[19] report" any time a limit in Conditions 34 and 35 has been exceeded as described in Conditions 28.1 and 28.2 and / or summary report described in Condition 29 for EU ID 12 (only when fired with diesel fuel). Written reports of excess emissions shall include the following information[20]:

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.7(c), Subpart A]

28.1. The magnitude of excess emissions computed in accordance with 40 C.F.R. 60.13(h), 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.

[40 C.F.R. 60.7(c)(1)]

28.2. Identification of each period of excess emissions that occurred during startup, shutdown, and malfunction of affected facility, the nature and cause of any malfunction, and the corrective action taken or preventative measures adopted.

[40 C.F.R. 60.7(c)(2)]

[19] The Federal EEMSP report is not the same as the State excess emission report required by Condition 78.

[20] Periods of excess emissions and monitor downtime are defined in 40 C.F.R. 60.334(j)(2) for Subpart GG affected units.

29. NSPS Subpart A EEMSP 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 (see Attachment A in the Statement of Basis) for each pollutant monitored for EU ID 12[21] The report shall be submitted semiannually, postmarked by the 30th day following the end of each 6-month period, except when more frequent reporting is specifically required by an applicable subpart, case-by-case basis, or the EPA, as follows:

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.7(c) & (d), Subpart A]

29.1. 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 unle**ss** the EEMSP report described in Condition 28 is requested, or

[40 C.F.R. 60.7(d)(1), Subpart A]

29.2. If the total duration of excess emissions for the reporting period is one percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is five percent or greater of the total time for the reporting period, then submit a summary report form **and the EEMSP** report described in Condition 28.

[40 C.F.R. 60.7(d)(2), Subpart A]

30. NSPS Subpart A Performance (Source) Tests. The Permittee shall conduct source tests according to Section 6 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:

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.8(a), Subpart A]

30.1. 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.

[40 C.F.R. 60.8(b), Subpart A]

30.2. Conduct source tests under conditions specified by EPA to be based on representative performance of EU IDs 12 and 13.

[40 C.F.R. 60.8(c), Subpart A]

30.3. Notify the Department and EPA at least 30 days in advance of the source test.

[40 C.F.R. 60.8(d), Subpart A]

[21] The reports under Conditions 28 and 29 are only required in cases where the Permittee periodically monitors fuel sulfur content, or uses a CMS to determine NOx emissions. As allowed under 40 C.F.R. 60.334(h)(1), the Permittee is not monitoring natural gas sulfur content to determine SO_2 emissions. The Permittee also does not use a CMS to determine NOx emissions. As a result, the reporting requirements currently only apply to EU ID 12 diesel fuel operation.

30.4. Provide adequate sampling ports, safe sampling platform(s), safe access to sampling platform(s), and utilities for sampling and testing equipment.

[40 C.F.R. 60.8(e), Subpart A]

31. **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 EU IDs 12 and 13 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 EU IDs 12 and 13.

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.11(d), Subpart A]

32. **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 Conditions 34 and 35 nothing in 40 C.F.R. Part 60 shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether EU IDs 12 and 13 would have been in compliance with applicable requirements of 40 C.F.R. Part 60 if the appropriate performance or compliance test or procedure had been performed.

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.11(g), Subpart A]

33. **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 Conditions 34, 35, and 37. 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.

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.12, Subpart A]

NSPS Subpart GG[22] – Stationary Gas Turbines

EU IDs 12 and 13

34. **NSPS Subpart GG NO_X Standard.** The Permittee shall not allow the exhaust gas concentration of NOx from

34.1. EU ID 12 (natural gas fired) and EU ID 13 to exceed 212 ppmv at 15 percent oxygen (O_2) dry exhaust basis; and

34.2. EU ID 12 (diesel fired) to exceed 205 ppmv at 15 percent O_2 dry exhaust basis.

[18 AAC 50.040(a)(2)(V)]

[22] The provisions of NSPS Subpart GG listed in Conditions 34 through 35 are current as amended through December 4, 2020. Should EPA promulgate revisions to this subpart, the Permittee shall be subject to the revised final provisions as promulgated and not the superseded provisions summarized in these conditions.

[40 C.F.R. 60.332(a)(2) & (d), Subpart GG]

34.3. **Monitoring**. The Permittee shall comply with the following:

[18 AAC 50.040(j) & 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3)(i) & (c)(6)]

a. **Periodic Testing**. For each turbine subject to Condition 34 that operates for 400 hours or more in any 12-month period during the life of this permit, the Permittee shall satisfy either Condition 34.3.a(i) or 34.3.a(ii).

(i) For existing turbines whose latest emissions source testing was certified as operating at less than or equal to 90 percent of the limit shown in Condition 34, the Permittee shall conduct a NO_X and O_2 source test under 40 C.F.R. 60, Appendix A, Method 20, or Method 7E and either Method 3 or 3A, within the first applicable criteria below in the noted timeframe:

(A) Within 5 years of the latest performance test, or

(B) Within 1 year of the effective date of this permit if the last source test occurred greater than five years prior to the effective date of this permit and the 400-hour threshold was triggered within 6 months of the permit's effective date, or

(C) Within 1 year after exceeding 400 hours of operation in a 12-month period if the last source test occurred greater than 4 years prior to the exceedance.

(ii) For existing turbines whose latest emissions source testing was certified as operating at greater than 90 percent of the limit shown in Condition 34, the Permittee shall conduct a NO_X and O_2 source test under 40 C.F.R. 60, Appendix A, Method 20, or Method 7E and either Method 3 or 3A, annually until two consecutive tests show performance results certified at less than or equal to 90 percent of the limit in Condition 34.

b. **Substituting Test Data**. The Permittee may use a source test completed under Condition 34.3.a performed on only one of a group of turbines to satisfy the requirements of those conditions for the other turbines in the group if

(i) the Permittee demonstrates that test results are less than or equal to 90 percent of the emission limit of Condition 34, and are projected under Condition 34.3.c to be less than or equal to 90 percent of the limit at maximum load;

(ii) for any source test conducted after the effective date of this permit, the Permittee identifies in a source test plan under Condition 70

(A) the turbine to be tested;

(B) the other turbines in the group that are to be represented by the test; and

(C) why the turbine to be tested is representative, including that each turbine in the group

(1) is located at a stationary source operated and maintained by the Permittee;

(2) is tested under close to identical ambient conditions;

(3) is the same make and model and has identical injectors and combustor;

(4) uses the same fuel type from the same source.

(iii) The Permittee may not use substitute test results to represent emissions from a turbine or group of turbines if that turbine or group of turbines is operating at greater than 90 percent of the emission limit of Condition 34.

c. **Load**. The Permittee shall comply with the following:

(i) Conduct all tests under Condition 34.3 in accordance with 40 C.F.R. 60.335, except as otherwise approved in writing by the Department, or by EPA if the circumstances at the time of the EPA approval are still valid. For the highest load condition, if it is not possible to operate the turbine during the test at maximum load, the Permittee will test the turbine when operating at the highest load achievable by the turbine under the ambient and stationary source operating conditions in effect at the time of the test.

(ii) Demonstrate in the source test plan for any test performed after the effective date of this permit whether the test is scheduled when maximum NO_X emissions are expected.

(iii) If the highest operating rate tested is less than the maximum load of the tested turbine or another turbine represented by the test data,

(A) for each such turbine the Permittee shall provide to the Department as an attachment to the source test report

(1) additional test information from the manufacturer or from previous testing of units in the group of turbines; if using previous testing of the group of turbines, the information must include all available test data for the turbines in the group, and

(2) a demonstration based on the additional test information that projects the test results from Condition 34.3 to predict the highest load at which emissions will comply with the limit in Condition 34;

(B) the Permittee shall not operate any turbine represented by the test data at loads for which the Permittee's demonstration predicts that emissions will exceed the limit of Condition 34;

(C) the Permittee shall comply with a written finding prepared by the Department that

(1) the information is inadequate for the Department to reasonably conclude that compliance is assured at any load greater than the test load, and that the Permittee must not exceed the test load,

(2) the highest load at which the information is adequate for the Department to reasonably conclude that compliance assured is less than maximum load, and the Permittee must not exceed the highest load at which compliance is predicted, or

(3) the Permittee must retest during a period of greater expected demand on the turbine, and

(D) the Permittee may revise a load limit by submitting results of a more recent Method 20, or Method 7E and either Method 3 or 3A, test done at a higher load, and, if necessary, the accompanying information and demonstration described in Condition 34.3.c(iii)(A); the new limit is subject to any new Department finding under Condition 34.3.c(iii)(C) and

(iv) In order to perform a Method 20, or Method 7E and either Method 3 or 3A, emission test, the Permittee may operate a turbine at a higher load than that prescribed by Condition 34.3.c(iii).

(v) For the purposes of Conditions 34.3 through 34.5, maximum load means the hourly average load that is the smallest of

(A) 100 percent of manufacturer's design capacity of the gas turbine at ISO standard day conditions;

(B) the highest load allowed by an enforceable condition that applies to the turbine; or

(C) the highest load possible considering permanent physical restraints on the turbine or the equipment which it powers.

34.4. **Recordkeeping**. The Permittee shall keep records as follows:

[18 AAC 50.040(j) & 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3)(ii) & (c)(6)]

a. The Permittee shall comply with the following for each turbine for which a demonstration under Condition 34.3.c(iii) does not show compliance with the limit of Condition 34 at maximum load.

(i) The Permittee shall keep records of

(A) load; or

(B) as approved by the Department, surrogate measurements for load and the method for calculating load from those measurements.

(ii) Records in Condition 34.4.a shall be hourly or otherwise as approved by the Department.

(iii) Within one month after submitting a demonstration under Condition 34.3.c(iii)(A)(2) that predicts that the highest load at which emissions will comply is less than maximum load, or within one month of a Department finding under Condition 34.3.c(iii)(C), whichever is earlier, the Permittee shall propose to the Department how they will measure load or load surrogates, and shall propose and comply with a schedule for installing any necessary equipment and beginning monitoring. The Permittee shall comply with any subsequent Department direction on the load monitoring methods, equipment, or schedule.

b. For any turbine subject to Condition 34, that will operate less than 400 hours in any 12 consecutive months, the Permittee shall keep monthly records of the hours of operation.

34.5. **Reporting**. The Permittee shall keep report as follows

[18 AAC 50.040(j) & 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3)(iii) & (c)(6)]

a. In each operating report under Condition 79 the Permittee shall list for each turbine tested or represented by testing at less than maximum load and for which the Permittee must limit load under Condition 34.3.c(iii)

(i) the load limit;

(ii) the turbine identification; and

(iii) the highest load recorded under Condition 34.4.a during the period covered by the operating report.

b. In each operating report under Condition 79 for each turbine for which Condition 34.3 has not been satisfied because the turbine normally operates less than 400 hours in any 12 consecutive months, the Permittee shall identify

(i) the turbine;

(ii) the highest number of operating hours for any 12 consecutive months ending during the period covered by the report; and

(iii) any turbine that operated for 400 or more hours.

c. The Permittee shall report under Condition 78 if

(i) a test result exceeds the emission standard;

(ii) Method 20, or Method 7E and either Method 3 or 3A, testing is required under Condition 34.3.a(i) or 34.3.a(ii) but not performed, or

(iii) the turbine was operated at a load exceeding that allowed by Conditions 34.3.c(iii)(B) and 34.3.c(iii)(C); exceeding a load limit is deemed a single violation rather than a multiple violation of both monitoring and the underlying emission limit.

[18 AAC 50.220(a) - (c) & 50.040(a)(1)]
[40 C.F.R. 60.8(b), Subpart A]

35. NSPS Subpart GG SO_2 Standard. The Permittee shall comply with the fuel sulfur standard in Condition 35.1 below:

[18 AAC 50.040(a)(2)(V)]
[40 C.F.R. 60.333, Subpart GG]

35.1. Do not allow the sulfur content for the fuel burned in EU IDs 12 and 13 to exceed 0.8 percent by weight.

[40 C.F.R. 60.333(b), Subpart GG]

35.2. **Monitoring.** The Permittee shall monitor compliance with the standard listed in Condition 35.1, as follows:

[18 AAC 50.040(a)(2)(V)]
[40 C.F.R. 60.334 & 60.335, Subpart GG]

a. Monitor the total sulfur content of the fuel being fired in the turbine, except as provided in Condition 35.2.b. The sulfur content of the fuel must be determined using total sulfur methods described in 40 C.F.R. 60.335(b)(10) and Condition 35.3. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084–82, 94, D5504–01, D6228–98, or Gas Processors Association Standard 2377–86, which measure the major sulfur compounds may be used.

[40 C.F.R. 60.334(h)(1), Subpart GG]

b. The owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in 40 C.F.R. 60.331(u), regardless of whether an existing custom schedule approved by the Administrator requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration.[23]

[23] The Permittee submitted a demonstration to EPA indicating that the fuel gas combusted at the stationary source meets the definition of natural gas in 40 C.F.R. 60.331(u), pursuant to 40 C.F.R. 60.334(h)(3). EPA confirmed by letter dated December 11, 2006 stating that the fuel gas demonstration adequately meets the definition criteria for natural gas, as defined in 40 C.F.R. 60.331(u). Gaseous fuel sulfur monitoring under Condition 35.2.a and reporting under Conditions 28, 29, and 35.5.a do not apply to Subpart GG turbines that have demonstrated that natural gas fuel meets the definition of 40 C.F.R. 60.331(u) as set out by Condition 35.2.b.

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data, which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in 40 C.F.R. 75, Appendix D, Section 2.3.1.4 or 2.3.2.4 is required.

[40 C.F.R. 60.334(h)(3), Subpart GG]

c. For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

[40 C.F.R. 60.334(h)(4), Subpart GG]

d. The frequency of determining the sulfur content of the fuel shall be as follows:

[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 60.334(i), Subpart GG]

(i) Fuel oil. For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in Sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of Appendix D of 40 C.F.R Part 75 (i.e., flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.

[40 C.F.R. 60.334(i)(1), Subpart GG]

(ii) Gaseous fuel. For owners and operators that elect not to demonstrate sulfur content using options in Condition 35.2.b, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

[40 C.F.R. 60.334(i)(2), Subpart GG]

(iii) Custom schedules. Notwithstanding the requirements of Condition 35.2.d(ii), operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in 40 C.F.R. 60.334(i)(3)(i) and (i)(3)(ii), custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in Condition 35. The two custom sulfur monitoring schedules set forth in 40 C.F.R. 60.334(i)(3)(i)(A) through (D) and 60.334(i)(3)(ii) are acceptable without prior Administrative approval.

[40 C.F.R. 60.334(i)(3), Subpart GG]

35.3. **Test Methods and Procedures.** If the owner or operator is required under Conditions 35.2.d(i) or 35.2.d(iii) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using Conditions 35.3.a and/or 35.3.b:

[18 AAC 50.040(a)(2)(V)]
[40 C.F.R. 60.335(b)(10), Subpart GG]

a. For liquid fuels, ASTM D129–00, D2622–98, D4294–02, D1266–98, D5453–00 or D1552–01; or

[18 AAC 50.040(a)(2)(V)]
[40 C.F.R. 60.335(b)(10)(i), Subpart GG]

b. For gaseous fuels, ASTM D1072-80, 90; D3246-81, 92, 96; D4468-85; or D6667-01. The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

[40 C.F.R. 60.335(b)(10)(ii), Subpart GG]

c. The fuel analyses required under Condition 35.3 may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

[40 C.F.R. 60.335(b)(11), Subpart GG]

35.4. **Recordkeeping.** Keep records of the information required by Condition 35.2 in accordance with recordkeeping requirements in Condition 74.

[18 AAC 50.040(j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(3)(ii)]

35.5. **Reporting.** The Permittee shall report as follows:

a. For each affected EU that periodically determines the fuel sulfur content under Condition 35.2.a, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with 40 C.F.R. 60.7(c) as summarized in Condition 28 except where otherwise approved by a custom fuel monitoring schedule. Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction as described by 40 C.F.R. 60.334(j)(2).

[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 60.334(j), Subpart GG]

b. For each affected EU that demonstrates compliance with the sulfur standard in Condition 35.1 using either Conditions 35.2.b(i) or 35.2.b(ii), compliance will be affirmed with an annual compliance certification under Condition 80 that the gaseous fuel meets the definition of natural gas in 40 C.F.R. 60.331(u).

[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 71.6(a)(3)(iii)]]

Subpart IIII[24] – Compression Ignition Internal Combustion Engines (CI ICE)

EU ID 22

36. NSPS Subpart IIII Requirements. For EU ID 22, the Permittee shall comply with all applicable requirements in 40 C.F.R. 60 Subpart IIII for stationary compression ignition (CI) internal combustion engine (ICE) whose construction[25], modification[26], or reconstruction[27] commences after July 11, 2005, as identified in Conditions 37 – 42.

[18 AAC 50.040(j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]
[40 C.F.R. 60.4200(a), Subpart IIII]

36.1. Comply with the applicable provisions of Subpart A as specified in Table 8 to Subpart IIII.

[18 AAC 50.040(j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]
[40 C.F.R. 60.4218 & Table 8, Subpart IIII]

37. NSPS Subpart IIII Emission Standards. For EU ID 22:

37.1. The Permittee shall comply with the emission standards in Table D.

[24] The provisions of NSPS Subpart IIII listed in Conditions 36 through 42 are current as amended through December 4, 2020. Should EPA promulgate revisions to this subpart, the Permittee shall be subject to the revised final provisions as promulgated and not the superseded provisions summarized in these conditions.
[25] For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.
[26] As defined in 18 AAC 50.990(59).
[27] As defined in 18 AAC 50.990(88).

Table D – Engine Emission Standards (g/kW-hr)

EU ID	NO_X	NMHC	CO	PM
22	3.5	0.4	3.5	0.10

[18 AAC 50.040(j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]
[40 C.F.R. 60.4204(b), §60.4201(a), §1039.102(b), Table 7, Subpart IIII]

37.2. Owners and operators who conduct performance tests must meet the not-to-exceed standards as indicated in 40 C.F.R. 60.4212, for performance tests conducted in-use.

[40 C.F.R. 60.4204(d), Subpart IIII]

37.3. Operate and maintain the stationary CI ICE that achieve the emission standards in Condition 37.1 over the entire life of the engine.

[40 C.F.R. 60.4206, Subpart IIII]

38. NSPS Subpart IIII Fuel Requirements. The Permittee shall comply with the following:

38.1. For EU ID 22, the Permittee shall use diesel fuel that meets the following specifications:

a. A maximum sulfur content of 15 parts per million by weight (ppmw).

b. A minimum cetane number of 40, or a maximum aromatic content of 35 percent by volume.

[18 AAC 50.040(j)(4) & 50.326(j)]
[40 C.F.R. 60.4207(b), Subpart IIII]
[40 C.F.R. 80.510(b), Subpart IIII]

39. NSPS Subpart IIII Compliance Requirements. For EU ID 22, the Permittee must do all of the following, except as permitted under Condition 39.5:

[18 AAC 50.040(a)(2)(OO), (j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]
[40 C.F.R. 60.4211(a), Subpart IIII]

39.1. Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions.

39.2. Change only those emission-related settings that are permitted by the manufacturer.

39.3. Meet the requirements of 40 C.F.R. parts 89, 94 and/or 1068, as they apply to you.

[40 C.F.R. 60.4211(a)(1) through (3), Subpart IIII]

39.4. Comply with the emission standards in Condition 37.1 by purchasing an engine certified to the emission standards in Condition 37.1. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in 40 CFR 60.4211(g), specified in Condition 39.5.

[18 AAC 50.040(j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(3)(i & ii)]
[40 C.F.R. 60.4211(c), Subpart IIII]

39.5. If the Permittee does not install, configure, operate, and maintain the engine and control device according to the manufacturer's emission-related written instructions, or change emission-related settings in a way that is not permitted by the manufacturer, the Permittee shall demonstrate compliance for that engine as follows:

[18 AAC 50.040(a)(2)(OO), (j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]
[40 C.F.R. 60.4211(g), Subpart IIII]

a. Keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, conduct an initial performance test to demonstrate compliance with the applicable emission standards within one year of startup, or within one year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within one year after changing emission-related settings in a way that is not permitted by the manufacturer. Conduct subsequent performance testing every 8,760 hours of engine operation or three years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

[40 C.F.R. 60.4211(g)(3), Subpart IIII]

40. NSPS Subpart IIII Test Methods and Other Procedures. For EU ID 22, owners and operators who conduct performance tests must conduct the performance tests pursuant to NSPS Subpart IIII according to 40 C.F.R. 60.4212(a) and (c).

[40 C.F.R. 60.4212, Subpart IIII]

41. NSPS Subpart IIII Monitoring and Recordkeeping. For EU ID 22, the Permittee shall comply with the following:

41.1. Comply with either Condition 41.1.a(i) or 41.1.a(ii):

a. For each shipment of fuel:

(i) Keep receipts that specify fuel grade and amount and

(A) Test the fuel for sulfur content; or

(B) Obtain test results showing the fuel content of the fuel from the supplier or refinery; the test results must include a statement signed by the supplier or refinery of what fuel they represent; or

(ii) Test the sulfur content of the fuel in the storage tank for EU ID 27.

[40 C.F.R. 71.6(a)(3)(i) & (ii)]

41.2. Fuel testing under Condition 41.1.a(i) or 41.1.a(ii) must follow an appropriate method listed in 18 AAC 50.035(b)-(c) or 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1).

[40 C.F.R. 71.6(a)(3)(i) & (ii)]

42. NSPS Subpart IIII Reporting. The Permittee shall report as follows:

42.1. Demonstrate compliance with Condition 38.1 by including in the operating report required by Condition 79 a copy of the records required in Condition 41.1 for the period covered by the report.

42.2. Report in accordance with Condition 78 if any of the requirements in Conditions 36 through 42.1 are not met.

[18 AAC 50.040 (j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(3)(iii) & (c)(6)]

40 C.F.R. Part 63 National Emission Standards for Hazardous Air Pollutants (NESHAP)

Subpart A – General Provisions

43. NESHAP Subpart A Applicability. The Permittee shall comply with the applicable requirements of 40 C.F.R. 63 Subpart A as follows:

43.1. For diesel-fired engines EU IDs 10, 14, 15, and 22, the Permittee shall comply with the applicable requirements of 40 C.F.R. 63 Subpart A in accordance with the provisions for applicability of Subpart A in Table 8 to 40 C.F.R. 63, Subpart ZZZZ.

[18 AAC50.040(c)(1), (23) & (39), 50.040(j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(1) & (a)(3)]
[40 C.F.R. 63.1-63.15, Subpart A]
[40 C.F.R. 63.6665 & Table 8, Subpart ZZZZ]

NESHAP Subpart ZZZZ[28] – Stationary ICE

(EU IDs 10, 14, 15, and 22)

44. For EU ID 22, the Permittee shall comply with the requirements of 40 C.F.R. 63, Subpart ZZZZ by meeting the requirements of 40 C.F.R. 60, Subpart IIII in Conditions 36 – 40.

[40 C.F.R. 63.6590(c)(1), Subpart ZZZZ]

45. For EU IDs 10, 14, and 15, the Permittee shall comply with the requirements in Conditions 45.1 through 45.9.

[40 C.F.R. 71.6(c)(7)]

45.1. **Management Practices for Emergency CI ICE[29]:** For EU ID 14, conduct maintenance as follows:

[28] The provisions of NESHAP Subpart ZZZZ listed in Conditions 44 through 45 are current as of December 4, 2020. Should EPA promulgate revisions to this subpart, the Permittee shall be subject to the revised final provisions as promulgated and not the superseded provisions summarized in these conditions.

[29] If operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required under Conditions 45.1 and 45.2, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the Permittee may delay the management practice until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated.

[40 C.F. R. 63, Footnote 2 to Table 2d, Subpart ZZZZ]

a. Change oil and filter every 500 hours of operation or annually, whichever comes first; except as allowed by Condition 45.5;

b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first and replace as necessary; and

c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

[18 AAC 50.040(c)(23)]
[40 C.F.R. 63.6603 and Table 2d, Item 4, Subpart ZZZZ]

45.2. **Management Practices for Non-Emergency CI ICE.** For EU IDs 10 and 15, conduct maintenance as follows:

a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first, except as allowed by Condition 45.5;

b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and

c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

[18 AAC 50.040(c)(23)]
[40 C.F.R. 63.6603(a) and Table 2d, Item 1, Subpart ZZZZ]

45.3. **Good Air Pollution Control Practices.** For EU IDs 10, 14, and 15, at all times, operate and maintain the emission units, including any associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but not limited to monitoring results, review of operation, maintenance procedures and records, and inspection of the source.

[18 AAC 50.040(c)(23)]
[40 C.F.R. 63.6605(b), Subpart ZZZZ]

45.4. **Operation and Maintenance.**

a. For EU IDs 10, 14, and 15, the Permittee shall:

(i) Operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

[40 C.F.R. 63.6625(e)(3), Subpart ZZZZ]

(ii) Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period need for appropriate and safe loading of the engine, not to exceed 30 minutes.

[40 C.F.R. 63.6625(h) & Table 2d, Column 3, Subpart ZZZZ]

b. For emergency CI ICE EU ID 14, the Permittee shall install a non-resettable hour meter if one is not already installed.

[40 C.F.R. 63.6625(f), Subpart ZZZZ]

45.5. **Oil Analysis Program.** For EU IDs 10, 14, and 15, the Permittee has the option to utilize an oil analysis program to extend the specified oil change requirement in Conditions 45.1.a and 45.2.a as described below:

a. The oil analysis must be performed at the same frequency specified for changing the oil in Conditions 45.1.a and 45.2.a.

b. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows:

(i) total Base Number is less than 30 percent of the Total Base Number of the oil when new;

(ii) viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or

(iii) percent water content (by volume) is greater than 0.5.

c. If all of these condemning limits in Conditions 45.5.b(i) through 45.5.b(iii) are not exceeded, the engine owner or operator is not required to change the oil.

d. If any of the limits in Conditions 45.5.b(i) through 45.5.b(iii) are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis.

(i) If the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later.

e. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine.

f. The analysis program must be part of the maintenance plan for the engine as required in Condition 45.4.b.

[40 C.F.R. 63.6625(i), Subpart ZZZZ]

45.6. **Operating Hour Limits for Emergency Engines.** For EU ID 14, the Permittee shall operate the emergency stationary RICE according to the requirements in Conditions 45.6.a through 45.6.c. In order for the engine to be considered an emergency stationary RICE, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in Conditions 45.6.a through 45.6.c, is prohibited. If you do not operate the engine according to the requirements in Conditions 45.6.a through 45.6.c, the engine will not be considered an emergency engine and must meet all requirements for non-emergency engines.

[18 AAC 50.040(c)(23)]
[40 C.F.R. 63.6640(f), NSPS Subpart ZZZZ]

a. There is no time limit on the use of emergency stationary RICE in emergency situations.

[40 C.F.R. 63.6640(f)(1)]

b. The Permittee may operate the emission unit for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of these units is limited to 100 hours per calendar year. The Permittee may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the Permittee maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

[40 C.F.R. 63.6640(f)(2)]

c. The Permittee may operate the emission unit up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing under Condition 45.6.b. The 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

[40 C.F.R. 63.6640(f)(4)]

45.7. **NESHAP Subpart ZZZZ Monitoring.** For EU IDs 10, 14, and 15, the Permittee must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Conditions 45.1 and 45.2 by:

[18 AAC 50.040(c)(23), (j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(1) & (a)(3)(i)]

a. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or

b. Developing and following your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

[40 C.F.R. 63.6640(a) & Table 6, Item 9, Subpart ZZZZ]

45.8. **NESHAP Subpart ZZZZ Recordkeeping:** The Permittee shall keep records as follows:

a. For EU ID 14, keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. Document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation.

[40 C.F.R. 63.6655(f) , Subpart ZZZZ]

b. For EU IDs 10, 14, and 15, keep records of the maintenance conducted on the stationary RICE to demonstrate that the Permittee operated and maintained the stationary RICE and after-treatment control device (if any) according to its own maintenance plan, including, but not limited to, the parameters analyzed, the results of the oil analysis, and the oil changes for the engine as part of the oil analysis program described in Condition 45.5.

[40 C.F.R. 63.6655(e), (e)(2), & (e)(3), Subpart ZZZZ]

c. For EU IDs 10, 14, and 15, keep records in a form suitable and readily available for expeditious review, according to 40 C.F.R. 63.10(b)(1), keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report or record and keep records readily accessible in hard copy or electronic form for at least five years after the date of each occurrence, measurement, maintenance, corrective action, report, or record.

[40 C.F.R. 63.6660, Subpart ZZZZ]
[40 C.F.R. 63.10(b)(1), and Table 8 to 40 C.F.R. 63, Subpart A]

45.9. **NESHAPs Subpart ZZZZ Reporting:** For EU IDs 10, 14, and 15, include in the operating report required by Condition 79 a report of all deviations as defined in 40 C.F.R. 63.6675 and of each instance in which an applicable requirement in 40 C.F.R. 63, Subpart A (as specified in Table 8 to Subpart ZZZZ) was not met.

[40 C.F.R. 63.6640(e), 63.6650(f), Subpart ZZZZ]

40 C.F.R. Part 61 National Emission Standards for Hazardous Air Pollutants (NESHAP)

Subpart A – General Provisions & Subpart M – Asbestos

46. The Permittee shall comply with the applicable requirements set forth in 40 C.F.R. 61.145, 61.150, and 61.152 of Subpart M, and the applicable sections set forth in 40 C.F.R. 61, Subpart A and Appendix A.

[18 AAC 50.040(b)(1) & (2)(F), & 50.326(j)]
[40 C.F.R. 61, Subparts A & M, and Appendix A]

40 C.F.R. Part 82 Protection of Stratospheric Ozone

47. **Subpart F – Recycling and Emissions Reduction.** The Permittee shall comply with the applicable standards for recycling and emission reduction of refrigerants set forth in 40 C.F.R. 82, Subpart F.

[18 AAC 50.040(d) & 50.326(j)]
[40 C.F.R. 82, Subpart F]

48. **Subpart G – Significant New Alternatives.** The Permittee shall comply with the applicable prohibitions set out in 40 C.F.R. 82.174 (Protection of Stratospheric Ozone Subpart G – Significant New Alternatives Policy Program).

[18 AAC 50.040(d) & 50.326(j)]
[40 C.F.R. 82.174(b) through (d), Subpart G]

49. **Subpart H – Halons Emissions Reduction.** The Permittee shall comply with the applicable prohibitions set out in 40 C.F.R. 82.270 (Protection of Stratospheric Ozone Subpart H – Halon Emission Reduction).

[18 AAC 50.040(d) & 50.326(j)]
[40 C.F.R. 82.270(b) through (f), Subpart H]

40 C.F.R. 63 NESHAP Applicability Determinations

50. The Permittee shall determine rule applicability and designation of affected sources under National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Source Categories (40 C.F.R. 63) in accordance with the procedures described in 40 C.F.R. 63.1(b).

50.1. If an owner or operator of a stationary source who is in the relevant source category determines that the source is not subject to a relevant standard or other requirement established under 40 C.F.R. 63, the owner or operator must keep a record as specified in 40 C.F.R. 63.10(b)(3).

50.2. If a source becomes affected by an applicable subpart of 40 C.F.R. 63, the owner or operator shall comply with such standard by the compliance date established by the Administrator in the applicable subpart, in accordance with 40 C.F.R. 63.6(c).

50.3. After the effective date of any relevant standard promulgated by the Administrator under this part, an owner or operator who constructs a new affected source that is not major-emitting or reconstructs an affected source that is not major-emitting that is subject to such standard, or reconstructs a source such that the source becomes an affected source subject to the standard, must notify the Administrator and the Department of the intended construction or reconstruction. The notification must be submitted in accordance with the procedures in 40 C.F.R. 63.9(b).

[18 AAC 50.040(c)(1), 50.040(j), & 50.326(j)]
[40 C.F.R. 71.6(a)(3)(ii)]
[40 C.F.R. 63.1(b), 63.5(b)(4), 63.6(c)(1), 63.9(b), & 63.10(b)(3), Subpart A]

Section 5. General Conditions

Standard Terms and Conditions

51. 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.

[18 AAC 50.326(j)(3), 50.345(a) & (e)]

52. The permit may be modified, reopened, revoked and reissued, or terminated for cause. A request by the Permittee for modification, revocation and re-issuance, or termination or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

[18 AAC 50.326(j)(3), 50.345(a) & (f)]

53. The permit does not convey any property rights of any sort, nor any exclusive privilege.

[18 AAC 50.326(j)(3), 50.345(a) & (g)]

54. **Administration Fees.** The Permittee shall pay to the Department all assessed permit administration fees. Administration fee rates are set out in 18 AAC 50.400-403.

[18 AAC 50.326(j)(1), 50.400, & 50.403]
[AS 37.10.052(b) & AS 46.14.240]

55. **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. 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:

55.1. potential to emit of 1,635 TPY; or

55.2. projected annual rate of emissions, in TPY, 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.

[18 AAC 50.040(j)(4), 50.035, 50.326(j)(1) & (3), 50.346(b)(1), 50.410, & 50.420]

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

56.1. 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 55.2. 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/.

56.2. 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.

56.3. 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 in Condition 55.1.

[18 AAC 50.040(j)(4), 50.326(j)(1) & (3), 50.346(b)(1), 50.410, & 50.420]

57. Good Air Pollution Control Practice (GAPCP). The Permittee shall do the following for EU IDs 8 and 9:

57.1. perform regular maintenance considering the manufacturer's or the operator's maintenance procedures;

57.2. keep records of any maintenance that would have a significant effect on emissions; the records may be kept in electronic format; and

57.3. keep a copy of either the manufacturer's or the operator's maintenance procedures.

[18 AAC 50.326(j)(3) & 50.346(b)(5)]

58. Dilution. The Permittee shall not dilute emissions with air to comply with this permit. Monitoring shall consist of an annual certification that the Permittee does not dilute emissions to comply with this permit.

[18 AAC 50.045(a)]

59. 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.

59.1. 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 59.1.a or to address the results of Department inspections that found potential problems; and

(ii) to prevent future dust problems.

59.2. The Permittee shall report according to Condition 61.3.

[18 AAC 50.045(d), 50. 326(j)(3), & 50.346(c)]

60. Stack Injection. The Permittee shall not release materials other than process emissions, products of combustion, or materials introduced to control pollutant emissions from a stack at a stationary source constructed or modified after November 1, 1982, except as authorized by a construction permit, Title V permit, or air quality control permit issued before October 1, 2004.

[18 AAC 50.055(g)]

61. 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.

[18 AAC 50.040(j)(4), 50.110, 50.326(j)(3) & 50.346(a)]
[40 C.F.R. 71.6(a)(3)]

61.1. **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 61.

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 61; or

(ii) the Department notifies the Permittee that it has found a violation of Condition 61.

61.2. **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 61; and

d. any corrective actions taken or planned for complaints attributable to emissions from the stationary source.

61.3. **Reporting.** The Permittee shall report as follows:

a. With each stationary source operating report under Condition 79, 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 78.

62. **Technology-Based Emission Standard.** If an unavoidable emergency, malfunction (as defined in 18 AAC 50.235(d)), or non-routine repair (as defined in 18 AAC 50.990(64), causes emissions in excess of a technology-based emission standard[30] listed in Conditions 34, 35, 37, 38, and 47 (refrigerants), the Permittee shall

62.1. take all reasonable steps to minimize levels of emissions that exceed the standard; and

62.2. report in accordance with Condition 78.1.b; the report must include information on the steps taken to mitigate emissions and corrective measures taken or to be taken.

[18 AAC 50.235(a), 50.326(j)(4), & 50.040(j)(4)]
[40 C.F.R. 71.6(c)(6)]

Open Burning Requirements

63. **Open Burning.** If the Permittee conducts open burning at this stationary source, the Permittee shall comply with the requirements of 18 AAC 50.065.

63.1. The Permittee shall keep written records to demonstrate that the Permittee complies with the requirements of 18 AAC 50.065. Upon request by the Department, submit copies of the records.

63.2. Compliance with this condition shall be an annual certification conducted under Condition 80.

[18 AAC 50.065, 50.040(j), & 50.326(j)]
[40 C.F.R. 71.6(a)(3)]

[30] As defined in 18 AAC 50.990(106), the term "*technology-based emission standard*" means a best available control technology (BACT) standard; a lowest achievable emission rate (LAER) standard; a maximum achievable control technology (MACT) standard established under 40 C.F.R. 63, Subpart B, adopted by reference in 18 AAC 50.040(c); a standard adopted by reference in 18 AAC 50.040(a) or (c); and any other similar standard for which the stringency of the standard is based on determinations of what is technologically feasible, considering relevant factors.

Section 6. General Source Testing and Monitoring Requirements

64. Requested Source Tests. In addition to any source testing explicitly required by the permit, the Permittee shall conduct source testing as requested by the Department to determine compliance with applicable permit requirements.

[18 AAC 50.220(a) & 50.345(a) & (k)]

65. Operating Conditions. Unless otherwise specified by an applicable requirement or test method, the Permittee shall conduct source testing

[18 AAC 50.220(b)]

65.1. at a point or points that characterize the actual discharge into the ambient air; and

65.2. 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.

66. Reference Test Methods. The Permittee shall use the following test methods when conducting source testing for compliance with this permit:

66.1. Source testing for compliance with requirements adopted by reference in 18 AAC 50.040(a) must be conducted in accordance with the methods and procedures specified in 40 C.F.R. 60.

[18 AAC 50.220(c)(1)(A) & 50.040(a)]
[40 C.F.R. 60]

66.2. Source testing for compliance with requirements adopted by reference in 18 AAC 50.040(b) must be conducted in accordance with the methods and procedures specified in 40 C.F.R. 61.

[18 AAC 50.040(b) & 50.220(c)(1)(B)]
[40 C.F.R. 61]

66.3. Source testing for compliance with requirements adopted by reference in 18 AAC 50.040(c) must be conducted in accordance with the source test methods and procedures specified in 40 C.F.R. 63.

[18 AAC 50.040(c) & 50.220(c)(1)(C)]
[40 C.F.R. 63]

66.4. Source testing for the reduction in visibility through the exhaust effluent must be conducted in accordance with the procedures set out in Reference Method 9. The Permittee may use the form in Section 12 to record data.

[18 AAC 50.030 & 50.220(c)(1)(D)]

66.5. 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.

[18 AAC 50.040(a)(3) & 50.220(c)(1)(E)]

[40 C.F.R. 60, Appendix A]

66.6. 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.

[18 AAC 50.035(b)(2) & 50.220(c)(1)(F)]
[40 C.F.R. 51, Appendix M]

66.7. Source testing for emissions of any pollutant may be determined using an alternative method approved by the Department in accordance with 40 C.F.R. 63 Appendix A, Method 301.

[18 AAC 50.040(c)(32) & 50.220(c)(2)]
[40 C.F.R. 63, Appendix A, Method 301]

67. Excess Air Requirements. To determine compliance with this permit, standard exhaust gas volumes must include only the volume of gases formed from the theoretical combustion of the fuel, plus the excess air volume normal for the specific emissions unit type, corrected to standard conditions (dry gas at 68° F and an absolute pressure of 760 millimeters of mercury).

[18 AAC 50.220(c)(3) & 50.990(102)]

68. Test Exemption. The Permittee is not required to comply with Conditions 70, 71 and 72 when the exhaust is observed for visible emissions by Method 9 Plan (Condition 2.1).

[18 AAC 50.345(a)]

69. 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.

[18 AAC 50.345(a) & (l)]

70. Test Plans. Except as provided in Condition 68, 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 64 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.

[18 AAC 50.345(a) & (m)]

71. Test Notification. Except as provided in Condition 68, at least 10 days before conducting a source test, the Permittee shall give the Department written notice of the date and the time the source test will begin.

[18 AAC 50.345(a) & (n)]

72. **Test Reports.** Except as provided in Condition 68, 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 75. If requested in writing by the Department, the Permittee must provide preliminary results in a shorter period of time specified by the Department.

[18 AAC 50.345(a) & (o)]

73. **Particulate Matter Calculations.** In source testing for compliance with the particulate matter standards in Conditions 5 and 25.2, the three-hour average is determined using the average of three one-hour test runs.

[18 AAC 50.220(f)]

Section 7. General Recordkeeping and Reporting Requirements

Recordkeeping Requirements

74. The Permittee shall keep all records required by this permit for at least five years after the date of collection, including:

74.1. Copies of all reports and certifications submitted pursuant to this section of the permit; and

74.2. Records of all monitoring required by this permit, and information about the monitoring including

a. the date, place, and time of sampling or 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.

[18 AAC 50.040(a)(1) & 50.326(j)]
[40 C.F.R 60.7(f), Subpart A, 40 C.F.R 71.6(a)(3)(ii)(B)]

Reporting Requirements

75. 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 emission 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.

75.1. 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.

[18 AAC 50.205, 50.326(j)(3), 50.345(a) & (j), & 50.346(b)(10)]

76. 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.

76.1. 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/.

[18 AAC 50.326(j)(3) & 50.346(b)(10)]

77. 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 and 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.

[18 AAC 50.345(a) & (i), 50.200, & 50.326(a) & (j)]
[40 C.F.R. 71.5(a)(2) & 71.6(a)(3)]

78. Excess Emissions and Permit Deviation Reports. The Permittee shall report excess emissions and permit deviations as follows:

78.1. **Excess Emissions Reporting.** Except as provided in Condition 61, 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 78.1.d.

d. Report all other excess emissions not described in Conditions 78.1.a, 78.1.b, and 78.1.c 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 79 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.

78.2. **Permit Deviations Reporting.** For permit deviations that are not "excess emissions," as defined under 18 AAC 50.990:

a. Report according to the required deadline for failure to monitor, as specified in other applicable conditions of this permit (Conditions 4.2.b and 8.3.b).

b. 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 79 for permit deviations that occurred during the period covered by the report, whichever is sooner.

78.3. **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 Section 13 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/.

[18 AAC 50.235(a)(2), 50.240(c), 50.326(j)(3), & 50.346(b)(2) & (3)]

79. Operating Reports. During the life of this permit[31], the Permittee shall submit to the Department an operating report in accordance with Conditions 75 and 76 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.

79.1. 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.

79.2. When excess emissions or permit deviations that occurred during the reporting period are not included with the operating report under Condition 79.1, the Permittee shall identify

a. the date of the excess emissions or 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 preventive measures taken and the date(s) of such actions; or

[31] *Life of this permit* is defined as the permit effective dates, including any periods of reporting obligations that extend beyond the permit effective dates. For example, if a permit expires prior to the end of a calendar year, there is still a reporting obligation to provide operating reports for the periods when the permit was in effect.

79.3. when excess emissions or permit deviation reports have already been reported under Condition 78 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.

79.4. The operating report must include, for the period covered by the report, a listing of emissions monitored under Conditions 2.2.e, 6.2, 9.1, and 34.3.a 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.

79.5. **Transition from expired to renewed permit**. For the first period of this renewed operating permit, also provide the previous permit's operating report elements covering that partial period immediately preceding the effective date of this renewed permit.

[18 AAC 50.346(b)(6) & 50.326(j)]
[40 C.F.R. 71.6(a)(3)(iii)(A)]

80. Annual Compliance Certification. Each year by March 31, the Permittee shall compile and submit to the Department an annual compliance certification report according to Condition 76.

80.1. Certify the compliance status of the stationary source over the preceding calendar year consistent with the monitoring required by this permit, as follows:

a. identify each term or condition set forth in Section 3 through Section 9, that is the basis of the certification;

b. briefly describe each method used to determine the compliance status;

c. state whether compliance is intermittent or continuous; and

d. identify each deviation and take it into account in the compliance certification.

80.2. **Transition from expired to renewed permit**. For the first period of this renewed operating permit, also provide the previous permit's annual compliance certification report elements covering that partial period immediately preceding the effective date of this renewed permit.

80.3. In addition, submit a copy of the report directly to the Clean Air Act Compliance Manager, US EPA Region 10, ATTN: Air Toxics and Enforcement Section, Mail Stop: 20-C04, 1200 Sixth Avenue, Suite 155, Seattle, WA 98101-3188.

[18 AAC 50.205, 50.345(a) & (j), & 50.326(j)]
[40 C.F.R. 71.6(c)(5)]

81. 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, NO_x, PM_{10}, $PM_{2.5}$, SO_2, VOC and lead (Pb) and lead compounds, as follows:

81.1. **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, NO_X or SO_2.

81.2. **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}, $PM_{2.5}$, NO_X or VOCs.

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 81.2.b(iv) through 81.2.b(viii);

(iv) 70 TPY of SO_2, NH_3, $PM_{2.5}$, NO_x, or VOC in $PM_{2.5}$ serious nonattainment areas; or

(v) 70 TPY of PM_{10} in PM_{10} serious nonattainment areas; or

(vi) 50 TPY of NO_x or VOC in O_3 serious nonattainment areas; or

(vii) 25 TPY of NO_x or VOC in O_3 severe nonattainment areas; or

(viii) 10 TPY of NO_x or VOC in O_3 extreme nonattainment areas.

81.3. For reporting under Condition 81.2, the Permittee shall report the annual emissions and the required data elements under Condition 81.4 every third year for the previous calendar year as scheduled by the EPA.[32]

81.4. For each emissions unit and the stationary source, include in the report the required data elements[33] 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.

81.5. 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/.

[18 AAC 50.040(j)(4), 50.200, 50.326(j)(3), & 50.346(b)(8)]
[40 C.F.R. 51.15, 51.30(a)(1) & (b)(1), and Appendix A to 40 C.F.R. 51 Subpart A]

82. NSPS and NESHAP Reports. The Permittee shall comply with the following:

82.1. **Reports:** Except for previously submitted reports and federal reports and notices submitted through EPA's Central Data Exchange (CDX) and Compliance and Emissions Data Reporting Interface (CEDRI) online reporting system, attach to the operating report required by Condition 79 for the period covered by the report, a copy of any NSPS and NESHAP reports submitted to the U.S. Environmental Protection Agency (EPA) Region 10. For reports previously submitted to ADEC or submitted through CDX/CEDRI, state in the operating report the date and a brief description of each of the online reports submitted during the reporting period.

82.2. **Waivers**: Upon request by the Department, provide a written copy of any EPA-granted alternative monitoring requirement, custom monitoring schedule or waiver of the federal emission standards, recordkeeping, monitoring, performance testing, or reporting requirements. The Permittee shall keep a copy of each U.S. EPA-issued monitoring waiver or custom monitoring schedule with the permit.

[18 AAC 50.040(j)(4) and 50.326(j)(4)]
[40 C.F.R. 60.13, 63.10(d) & (f) and 40 C.F.R. 71.6(c)(6)]

[32] 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.).

[33] 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. Permit Changes and Renewal

83. Permit Applications and Submittals. The Permittee shall comply with the following requirements for submitting application information to the EPA:

83.1. The Permittee shall provide a copy of each application for modification or renewal of this permit, including any compliance plan, or application addenda, at the time the application or addendum is submitted to the Department;

83.2. The information shall be submitted to the Part 70 Operating Permit Program, US EPA Region 10, Air Permits and Toxics Branch, Mail Stop: 15-H13, 1200 Sixth Avenue, Suite 155, Seattle, WA 98101-3188;

83.3. To the extent practicable, the Permittee shall provide to EPA applications in portable document format (pdf), MS Word format (.doc), or other computer-readable format compatible with EPA's national database management system; and

83.4. The Permittee shall maintain records as necessary to demonstrate compliance with this condition.

[18 AAC 50.040(j)(7), 50.326(a) & (j)(3), and 50.346(b)(7)]
[40 C.F.R. 71.10(d)(1)]

84. Emissions Trading. No permit revision shall be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in the permit.

[18 AAC 50.040(j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(8)]

85. Off Permit Changes. The Permittee may make changes that are not addressed or prohibited by this permit other than those subject to the requirements of 40 C.F.R. Parts 72 through 78 or those that are modifications under any provision of Title I of the Act to be made without a permit revision, provided that the following requirements are met:

85.1. Each such change shall meet all applicable requirements and shall not violate any existing permit term or condition;

85.2. Provide contemporaneous written notice to EPA and the Department of each such change, except for changes that qualify as insignificant under 18 AAC 50.326(d) – (i). Such written notice shall describe each such change, including the date, any change in emissions, pollutants emitted, and any applicable requirement that would apply as a result of the change;

85.3. The change shall not qualify for the shield under 40 C.F.R. 71.6(f);

85.4. The Permittee shall keep a record describing changes made at the stationary source that result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from those changes.

[18 AAC 50.040(j)(4) & 50.326(j)(4)]
[40 C.F.R. 71.6(a)(12)]

86. Operational Flexibility. The Permittee may make CAA Section 502(b)(10)[34] changes within the permitted stationary source without requiring a permit revision if the changes are not modifications under any provision of Title I of the Act and the changes do not exceed the emissions allowable under this permit (whether expressed therein as a rate of emissions or in terms of total emissions):

86.1. The Permittee shall provide EPA and the Department with a written notification no less than seven days in advance of the proposed change.

86.2. For each such change, the notification required by Condition 86.1 shall include a brief description of the change within the permitted stationary source, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change.

86.3. The permit shield described in 40 C.F.R. 71.6(f) shall not apply to any change made pursuant to Condition 86.

[18 AAC 50.040(j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(13)]

87. Permit Renewal. To renew this permit, the Permittee shall submit to the Department[35] an application under 18 AAC 50.326 no sooner than [18 months before the expiration date of this permit] and no later than [6 months before the expiration date of this permit]. The renewal application shall be complete before the permit expiration date listed on the cover page of this permit. Permit expiration terminates the stationary source's right to operate unless a timely and complete renewal application has been submitted consistent with 40 C.F.R. 71.7(b) and 71.5(a)(1)(iii).

[18 AAC 50.040(j)(3), 50.326(c) & (j)(2)]
[40 C.F.R. 71.5(a)(1)(iii) & 71.7(b) & (c)(1)(ii)]

[34] As defined in 40 C.F.R. 71.2, CAA Section 502(b)(10) changes are changes that contravene an express permit term. Such changes do not include changes that would violate applicable requirements or contravene federally enforceable permit terms and conditions that are monitoring (including test methods), recordkeeping, reporting, or compliance certification requirements.

[35] Submit permit applications to the Department's Anchorage office. The current address is: Air Permit Intake Clerk, ADEC, 555 Cordova Street, Anchorage, AK 99501.

Section 9. Compliance Requirements

General Compliance Requirements

88. Compliance with permit terms and conditions is considered to be compliance with those requirements that are

88.1. included and specifically identified in the permit; or

88.2. determined in writing in the permit to be inapplicable.

[18 AAC 50.326(j)(3) & 50.345(a) & (b)]

89. 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

89.1. an enforcement action;

89.2. permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280; or

89.3. denial of an operating permit renewal application.

[18 AAC 50.040(j), 50.326(j) & 50.345(a) & (c)]

90. For applicable requirements with which the stationary source is in compliance, the Permittee shall continue to comply with such requirements.

[18 AAC 50.040(j)(3) & (4) and 50.326(j)]
[40 C.F.R. 71.6(c)(3) & 71.5(c)(8)(iii)(A)]

91. 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.

[18 AAC 50.326(j)(3) & 50.345(a) & (d)]

92. 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

92.1. enter upon the premises where a source subject to the permit is located or where records required by the permit are kept;

92.2. have access to and copy any records required by the permit;

92.3. inspect any stationary source, equipment, practices, or operations regulated by or referenced in the permit; and

92.4. sample or monitor substances or parameters to assure compliance with the permit or other applicable requirements.

[18 AAC 50.326(j)(3) & 50.345(a) & (h)]

93. For applicable requirements that will become effective during the permit term, the Permittee shall meet such requirements on a timely basis.

[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 71.6(c)(3) & 71.5(c)(8)(iii)(B)]

Section 10. Permit As Shield from Inapplicable Requirements

In accordance with AS 46.14.290, and based on information supplied in the permit application, this section of the permit contains the requirements determined by the Department not to be applicable to the stationary source.

94. Nothing in this permit shall alter or affect the following:

94.1. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section; or

94.2. The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance.

[18 AAC 50.040(j)(4) and 50.326(j)]
[40 C.F.R. 71.6(f)(3)(i) & (ii)]

95. Table E identifies the emissions units that are not subject to the specified requirements at the time of permit issuance. If any of the requirements listed in Table E becomes applicable during the permit term, the Permittee shall comply with such requirements on a timely basis including, but not limited to, providing appropriate notification to EPA, obtaining a construction permit and/or an operating permit revision.

[18 AAC 50.040(j)(4) and 50.326(j)]
[40 C.F.R. 71.6(f)(1)(ii)]

Table E - Permit Shields Granted

EU ID	Requirements Not Applicable	Reason for Non-Applicability
Breakout Tank: EU ID 21 (TK-140)	40 C.F.R. 60 Subpart Ka - Standards of Performance for Storage Vessels for Petroleum Liquids	Commenced construction prior to effective date of subpart (May 18, 1978). The tank has not been modified or reconstructed since the effective date of the standard. The tank is a crude oil breakout tank (not storage vessels as defined in 40 C.F.R. 60) and part of a pipeline system as defined by 49 C.F.R. 195.2.
	40 C.F.R. 60 Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels)	Commenced construction prior to effective date of subpart (July 23, 1984). The tanks have not been modified or reconstructed since the effective date of the standard. The tanks are crude oil breakout tanks (not storage vessels as defined in 40 C.F.R. 60) and part of a pipeline system as defined by 49 C.F.R. 195.2.
Tank: TK-147	40 C.F.R. 60 Subpart K - Standards of Performance for Storage Vessels for Petroleum Liquids	The tank stores diesel fuel and diesel fuel oils are excluded from the definition of a petroleum liquid [40 C.F.R. 60.111(b)].
	40 C.F.R. 60 Subpart Ka - Standards of Performance for Storage Vessels for Petroleum Liquids	Commenced construction prior to effective date of subpart (May 18, 1978). The tank has not been modified or reconstructed since the effective date of the standard. In addition, diesel fuel oils are excluded from the definition of a petroleum liquid [40 C.F.R. 60.111a(b)].

EU ID	Requirements Not Applicable	Reason for Non-Applicability
	40 C.F.R. 60 Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels)	Commenced construction prior to effective date of subpart (July 23, 1984). The tanks have not been modified or reconstructed since the effective date of the standard.
Engines: EU IDs 10, 14, and 15	40 C.F.R. 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	Not affected units (unless modified or reconstructed in the future). These emission units were manufactured prior to April 1, 2006 applicability date (see 40 C.F.R. 60.4200(a)(2(i)), and have not been modified or reconstructed after July 11, 2005 (see 40 C.F.R. 60.4200(a)(3)).
Turbines: EU IDs 12 & 13	40 C.F.R. 60 Subpart A – General Provisions (portions of)	§60.7(a)(5) – (a)(7) – Do not apply because no continuous monitoring system is used. Opacity observation is not required because visible emissions are not regulated under Subpart GG. §60.13 – Does not apply because no continuous monitoring system or monitoring device as each term is defined in 60.2 is required under Subpart GG for EU IDs 12 and 13.
Turbines: EU IDs 12 & 13	40 C.F.R. 60 Subpart GG – Standards of Performance for Stationary Gas Turbines:	Standards for NOx: §60.332(a)(1) – Does not apply because EU IDs 12 and 13 are subject to §60.332(a)(2). §60.332(3) & (a)(4) – Do not apply because APSC has chosen not to take an allowance for fuel-bound nitrogen. Standard for Sulfur Dioxide: §60.333(a) – Does not apply because APSC has chosen to comply with the sulfur limit under §60.333(b). Monitoring of Operations: §60.334(a) and (b) – Apply only to turbines using water injection for NOx control. §60.334(c)-(g) – Optional monitoring methods (CEMS) that APSC chooses not to conduct. §60.334(h)(2) – Nitrogen monitoring under 60.334(h)(2) is not required because APSC has chosen not to claim an allowance for fuel bound nitrogen. §60.334(j) – Does not apply to EU IDs 12 (only when fired with natural gas) and 13 because no continuous monitoring of parameters or emissions is required.
Storage Tanks	40 C.F.R. 63 Subpart OO – National Emission Standards for Tanks – Level 1	Provisions only apply to tanks subject to a subpart of 40 C.F.R. 60, 61, or 63 that specifically reference 40 C.F.R. 63 Subpart OO. The stationary source does not include any tanks subject to any subpart of Part 60, 61, or 63.
Portable Storage Containers	40 C.F.R. 63 Subpart PP – National Emission Standards for Containers	Provisions only apply to portable containers, as defined in §63.921, subject to a subpart of 40 C.F.R. 60, 61, or 63 that specifically references 40 C.F.R. 63 Subpart PP. The stationary source does not include any containers subject to any subpart of Part 60, 61, or 63.
Drain Systems	40 C.F.R. 63 Subpart RR – National Emission Standards for Individual Drain Systems	Provisions only apply to drain systems affected by 40 C.F.R. 60, 61, or 63 that specifically reference 40 C.F.R. 63 Subpart

EU ID	Requirements Not Applicable	Reason for Non-Applicability
		RR. The stationary source does not include any drain systems subject to any subpart of Part 60, 61, or 63 [40 C.F.R. 63.960].
Oil-Water Separators	40 C.F.R. 63 Subpart VV – National Emission Standards for Oil-Water Separators and Organic-Water Separators	EPA stated that these provisions were placed within this standard only for convenience and only where a stationary source is subject to another Part 60, 61, or 63 subpart that references Subpart VV [40 C.F.R. 63.1040]. This stationary source is not subject to any subpart in Part 60, 61, or 63 that references Subpart VV.
Stationary Source - Wide	40 C.F.R. 51 Appendix Y – Guidelines for BART Determinations Under the Regional Haze Rule	PS-4 has been determined not to be a BART eligible source by the Department due to its distance from the nearest Class I area (Denali Park).
Stationary Source - Wide	40 C.F.R. 60 Subpart LLL - Standards of Performance for Onshore Natural Gas Processing Plants	Stationary source does not process natural gas [40 C.F.R. 60.640] and commenced construction prior to effective date of subpart (January 20, 1984). Stationary source has not been modified or reconstructed since the effective date of the standard.
Stationary Source - Wide	40 C.F.R. 61 Subpart A - General Provisions	Other than the asbestos renovation and demolition requirements of Subpart M this subpart does not apply to this stationary source because it only applies where there are subparts applicable to the stationary source and no other Part 61 subparts apply to this stationary source.
	40 C.F.R. 61 Subpart J - National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene	No process components in *benzene service*, as defined by subpart (10 percent benzene by weight) [40 C.F.R. 61.110 and 61.111].
	40 C.F.R. 61 Subpart V - National Emission Standard for Equipment Leaks (Fugitive Emission Sources)	No process components in *volatile hazardous air pollutant (VHAP) service*, as defined by subpart (≥10 percent VHAP by weight) [40 C.F.R. 61.241 and 61.245]. This subpart only applies where identified by another applicable Part 61 subpart [40 C.F.R. 61.240].
	40 C.F.R. 61 Subpart Y - National Emission Standard for Benzene Emissions from Benzene Storage Vessels	The stationary source does not have storage tanks that store benzene as defined by the standards in 40 C.F.R. 61.270(a).
	40 C.F.R. 61 Subpart BB - National Emission Standard for Benzene Emissions from Benzene Transfer Operations	Crude oil and petroleum distillates are exempt from this subpart [40 C.F.R. 61.300]. Other than crude oil and other petroleum distillates there are no other benzene containing substances where loading occurs at this stationary source.
	40 C.F.R. 61 Subpart FF - National Emission Standard for Benzene Waste Operations	This subpart only applies to chemical manufacturing plants, coke byproduct recovery plants and petroleum refineries [40 C.F.R. 61.340]. This stationary source does not include any of those activities.
Stationary Source - Wide	40 C.F.R. 61 Subpart M - National Emission Standard for Asbestos	§61.142 - - Standard for Asbestos Mills: APSC PS-4 is not an Asbestos Mill. §61.144 - Standard for Manufacturing: APSC PS-4 does not engage in any manufacturing operations using commercial asbestos.

EU ID	Requirements Not Applicable	Reason for Non-Applicability
		§61.146 - Standard for Spraying: APSC PS-4 does not spray apply asbestos containing materials. §61.147 - Standard for Fabricating: APSC PS-4 does not engage in any fabricating operations using commercial asbestos. §61.149 - Standard for Waste Disposal for Asbestos Mills: Applies only to those stationary sources subject to 40 C.F.R. 61.142 (Asbestos Mills). §61.151 - Standard for Inactive Waste Disposal Sites for Asbestos Mills and Manufacturing and Fabricating Operations: Applies only to those stationary sources subject to 40 C.F.R. 61.142, 61.144, or 61.147 (Asbestos Mills, manufacturing or fabricating). §61.153 - Standard for Reporting: No reporting requirements apply for sources subject to 40 C.F.R. 61.145 (demolition and renovation) [40 C.F.R. 61.153(a)]. §61.154 - Standard for Active Waste Disposal Sites: APSC PS-4 is not an active waste disposal site and does not receive asbestos containing waste material. §61.155 - Standard for Inactive Waste Disposal Sites for Asbestos Mills and Manufacturing and Fabricating Operations: APSC PS-4 does not process regulated asbestos containing material (RACM).
Stationary Source - Wide	40 C.F.R. 63 Subpart T - National Emission Standards for Halogenated Solvent Cleaning	Stationary source does not operate halogenated solvent cleaning machines.
	40 C.F.R. 63 Subpart CCCCCC NESHAP Source Category for Gasoline Dispensing Facilities (GDF)	Stationary Source does not meet the definition of a Gasoline Dispensing Facility under 40 C.F.R. 63.11132 because gasoline is not dispensed in "motor vehicles" as defined by CAA Section 216.
	40 C.F.R. 63 Subpart DDDDD – NESHAP for Industrial/Commercial/Institutional Boilers and Process Heaters	PS-4 is not a major source of HAPs as defined under any subpart of 40 C.F.R. 63.
	40 C.F.R. 63 Subpart EEEE – NESHAP for Organic Liquid Distribution (non-gasoline)	PS-4 is not a major source of HAPs as defined under any subpart of 40 C.F.R. 63.
	40 C.F.R. 63 Subpart HHHHHH – NESHAP for Paint Stripping and Miscellaneous Surface Coating Operations	MeCl is not used for paint stripping. Painting activities occurring at the stationary source meet the definition of facility maintenance as defined by 40 C.F.R. 63.11180, and thus, are categorically exempt from 63.11170(a)(2) & (3). This shield is not valid if APSC operations change in regards to using MeCl.
EU IDs 10, 14, 15, 19, & 20	40 C.F.R. Subpart ZZZZ §§63.6600, 63.6601, 63.6602, 63.6610, 63.6611	Requirements apply to affected units located at a major source. PS 4 is an area source of HAP emissions.

EU ID	Requirements Not Applicable	Reason for Non-Applicability
EU IDs 10, 14, & 15	40 C.F.R. Subpart ZZZZ emission limitations and operating limitations under Table 2b referenced by §63.6603(a)	Emergency CI RICE located at area sources are not subject to the numerical CO emissions limitations or the operating limitations related to oxidation catalysts in Table 2b.
	§63.6604	Emergency RICE are not subject to the fuel requirements under 63.6604.
	§§63.6612, 63.6615, and 63.6620	The performance test requirements and initial compliance demonstrations do not apply to emergency RICE not subject to numerical CO emission standards.
	§§63.6625(a)-(d)	Requirements apply to RICE using CEMS or CPMS to demonstrate compliance, to RICE burning landfill or digester gas, or to emergency RICE located at a major source of HAP emissions.
	§63.6625(g)	Emergency RICE are not subject to the crankcase control requirements under 63.6604.
	§63.6630	Does not apply because emergency RICE are not subject to numerical CO emission standards.
	§§63.6640(b) & (e)	Reporting requirements apply to RICE subject to an emission limitation or operating limitation.
	§§63.6645(a)	Per 63.6645(a)(5), notification requirements do not apply to emergency RICE.
	§§63.6645(b)-(h)	Notification requirements apply to RICE located at HAP major sources, or to RICE required to conduct a performance test or other initial compliance demonstration.
	§§63.6655(a) & (b)	These recordkeeping requirements only apply to RICE subject to an emission or operating limitation.
	§63.6655(c)	These recordkeeping requirements only apply to RICE burning landfill or digester gas.
Stationary Source – Wide	40 C.F.R. 64 – Compliance Assurance Monitoring (CAM)	Stationary source does not contain a pollutant-specific emitting unit that satisfies all of the following criteria: -The emission unit is subject to an applicable emission limitation or standard; -The unit uses a control device to comply with any such applicable emission limitation or standard; and

EU ID	Requirements Not Applicable	Reason for Non-Applicability
		-The unit has potential pre-control device emissions of the applicable regulated air pollutant equal to or greater than the major source thresholds for the applicable regulated air pollutant.
Stationary Source – Wide	40 C.F.R. 68 – Accidental Release: Risk Management Plan (RMP)	40 C.F.R Part 68 applies to "stationary sources" [40 C.F.R. 68.10]. "Stationary source" is defined for purposes of Part 68 to exclude stationary sources engaged in the transportation of hazardous liquids and subject to 49 C.F.R. Parts 192, 193, and 195 [40 C.F.R 68.3]. TAPS PS-4 transports and stores crude oil subject to the federal Pipeline Safety Act and 49 C.F.R Part 195. The transportation of crude oil by this pump station and the incidental storage in the pump station breakout tank are not activities that fall within the definition of a stationary source. Therefore, Part 68 does not apply to PS-4. There are no threshold quantities or other 112(r) regulated substances at PS-4. Therefore, Part 68 does not apply to PS-4. The fuel gas line is a 49 C.F.R. Part 192 facility and does not fall within the definition of a "stationary source" [40 C.F.R 68.2].
Stationary Source – Wide	40 C.F.R. 82.1 Subpart A – Production and Consumption Controls	Stationary source does not produce, transform, destroy, import or export Class 1 or Group I or II substances or products.
	40 C.F.R. 82.30 Subpart B – Servicing of Motor Vehicle Air Conditioners	Stationary source does not service motor vehicle air conditioners.
	40 C.F.R. 82.60 Subpart C – Ban on Nonessential Products Containing Class I Substances and Ban on Nonessential Products Containing or Manufactured with Class II Substances	Stationary source does not manufacture or distribute Class I and II products or substances.
	40 C.F.R. 82.80 Subpart D – Federal Procurement	Subpart applies only to Federal Departments, agencies, and instrumentalities.
	40 C.F.R. 82.100 Subpart E – The Labeling of Products Using Ozone-Depleting Substances	Stationary Source does not manufacture or distribute Class I and II products or substances.
	40 C.F.R. 82.158 Subpart F – Recycling and Emissions Reduction	Stationary source does not manufacture or import recovery and recycling equipment.
	40 C.F.R. 82.160 – Recycling and Emissions Reduction	Stationary source does not contract equipment testing organizations to certify recovery and recycling equipment.
	40 C.F.R. 82.164 – Recycling and Emissions Reduction	Stationary source does not sell reclaimed refrigerant.
Stationary Source - Wide	18 AAC 50.055(a)(2) – (a)(9)	Stationary source does not operate sources specific to the listed standards.
	18 AAC 50.055(b)(2) – (b)(6)	Stationary source does not operate sources specific to the listed standards.

EU ID	Requirements Not Applicable	Reason for Non-Applicability
	18 AAC 50.055(d) - (f)	Stationary source does not operate sources specific to the listed standards.
	18 AAC 50.075	Stationary source does not use wood-fired heating devices.

[18 AAC 50.326(j)]
[40 C.F.R. 71.6(f)(1)(ii)]

Section 11. Procedure for HAP Content of Crude Oil Storage Tank Vapors

This section provides a step-by-step procedure for determining the Hazardous Air Pollutants (HAPs) for the crude oil storage tank vapors. APSC will conduct laboratory tests of the crude oil to determine the weight fraction of various components. These weight fractions are then used, through many calculations, to determine the HAP emission rate from the tank.

I. Sample Description/Comments

1. Sample location ______________________________________
2. Sample Date ______________________________________
3. Sample ID ______________________________________
4. Core Laboratories data includes crude molecular weight and component wt% values.

II. Determine Component Mole Fractions in Liquid Crude

Methodology Assumptions/Comments:

1. The component mole fraction in crude is determined from component weight fraction and component molecular weight by assuming a mass of 1,000 lb of crude (see AP-42 Section 7.1.5).
2. The component molecular weight of Decanes+ is equal to the value required for the sum of all molecular weights to be equal to the Core Laboratories measured crude molecular weight of: _______lb/lb-mole

Liquid Crude Analysis Data		Calculate Component Mole Fraction in Crude			
Component **i**	Component Weight Fraction in Crude (wt%/100) $\mathbf{Z_{Li}}$	Component Molecular Weight $\mathbf{M_i}$	Total Moles of Crude (sum Z_{Li}/M_i x 1000) $\mathbf{x_T}$	Component Mole Fraction in Crude ($Z_{Li}/M_i/x_T$) $\mathbf{x_i}$	Crude Molecular Weight (sum M_i*x_i) $\mathbf{M_T}$
Methane		16			
Ethane		30			
Propane		44			
Isobutane		58			
N-Butane		58			
1,3 Butadiene		54			
Isopentane		72			
N-Pentane		72			
N-Hexane		86			
Hexane		84			
Benzene		78			
Heptanes		97			
2,2,4 Trimethylpentane		114			
Toluene		92			
Octanes		111			
Ethyl Benzene		106			
Xylenes		106			
Isopropylbenzene		120			
Nonanes		123			
Naphthalene		128			
Decanes+					
SUM Z_{Li} / x_T / x_iM_T	1.00			1.00	

Note:

1. Molecular weight values for component groups such as octanes are estimates from Core Laboratories.

III. Determine Component Vapor Pressure at Given Crude Temperature

Methodology Assumptions/Comments:

1. Clausius-Clapeyron equation provides relationship between temperature and vapor pressure:

   $\log P_2/P_1 = H_v/2.303R*(T_2\text{-}T_1/T_2T_1)$

   where: R = Universal Gas Constant = 8.31448 J/g-mole·K = 3.58 Btu/lb-mole·K
   H_v = Heat of Vaporization = see table below

2. Let P_1 be known component vapor pressure at known temperature T_1 = 100°F (311 K), and P_2 be unknown component vapor pressure at given crude temperature T_2 (shown below).

3. Pump station crude (and vapor) constant temperature (T_2) of: °F = K
   Based on average crude temperature at this Pump Station during the reporting period

Component Physical Properties			Component Vapor Pressure at Crude Temperature			
Component **i**	Component Vapor Pressure at 100°F (psia) $\mathbf{P_1}$	Component Heat of Vaporization (Btu/lb-mole) $\mathbf{H_v}$	Component Heat of Vaporization/ Gas Constant $H_v/2.303R$	Calculate $(T_2\text{-}T_1)/T_2T_1$	Calculate Inverse Log of $(Hv/2.303R)*(T_2\text{-}T_1)/T_2T_1$	Component Vapor Pressure at Crude Temperature (psia), $\mathbf{P_2}$
Methane		3520	426.9			
Ethane		6349	770.1			
Propane		8071	978.9			
Isobutane		9136	1108.2			
N-Butane		9642	1169.5			
1,3 Butadiene		10025	1215.9			
Isopentane		10613	1287.3			
N-Pentane		11082	1344.2			
N-Hexane		12404	1504.5			
Hexane		12500	1516.1			
Benzene		13215	1602.8			
Heptanes		13500	1637.4			
2,2,4 Trimethylpentane		14000	1698.1			
Toluene		14263	1730.0			
Octanes		14500	1758.7			
Ethyl Benzene		15288	1854.3			
Xylenes		16000	1940.6			
Isopropylbenzene		16136	1957.1			
Nonanes		16500	2001.3			
Naphthalene		16700	2025.5			
Decanes+		47282	5734.7			

Notes:

1 Heat of Vaporization and vapor pressure of pure components from GPSA Engineering Data Book, Volume II, Section 23.

2 Vapor Pressure values for component groups such as octanes are estimates from Core laboratories.

3 Heat of Vaporization values for component groups are estimates based on values for individual components within the group.

IV. Determine Component Partial Pressure and Mole Fraction in Crude Vapor

Methodology Assumptions/Comments:

1. Conservatively assume C_1 through C_{10} hydrocarbons and HAP's are only species present in vapor phase due to dramatic drop-off in component vapor pressure as component molecular weight increases.
2. For speciation purposes, assume crude vapor pressure (P_{VA}) equal to sum of component partial pressures indicated below. This assumption ignores CO_2 present in crude and is conservative because it results in vapor mole fractions of listed components (including HAP's) being overstated.
3. Component partial pressure is equal to the component mole fraction in the liquid crude multiplied by the component vapor pressure at the given crude temperature:

$$P_i = P_2 * x_i$$

4. The component mole fraction in the crude vapor is then equal to the component partial pressure divided by the overall crude vapor pressure:

$$y_i = P_i/P_{VA}$$

	Calculation of Component Partial Pressure and Mole Fraction in Vapor			
Component **i**	Component Vapor Pressure at Crude Temperature (psia) **P_2**	Component Mole Fraction in Crude ($Z_{Li}/M_i/x_T$) **x_i**	Component Partial Pressure at Crude Temperature ($P_2 * x_i$) **P_i**	Component Mole Fraction in Vapor (P_i/P_{VA}) **y_i**
Methane				
Ethane				
Propane				
Isobutane				
N-Butane				
1,3 Butadiene				
Isopentane				
N-Pentane				
N-Hexane				
Hexane				
Benzene				
Heptanes				
2,2,4 Trimethylpentane				
Toluene				
Octanes				
Ethyl Benzene				
Xylenes				
Isopropylbenzene				
Nonanes				
Naphthalene				
Decanes+				
P_{VA} / y_i SUM				1.00

V. Determine Component Weight Fractions in Crude Vapor

1. Component weight fraction in the vapor is determined in two steps. First, the overall vapor molecular weight is determined by summing the product of the molecular weight and vapor mole fraction for each component:

$$M_v = \text{sum } (M_i * y_i)$$

2. Then, the component weight fraction is determined by dividing the product of the molecular weight and vapor mole fraction for each component by the overall vapor molecular weight:

$$Z_{vi} = (M_i * y_i)/M_v$$

Component Physical Properties		**Calculation of Component Weight Fraction in Vapor**		
Component **i**	Component Molecular Weight **M_i**	Component Mole Fraction in Vapor (P_i/P_{VA}) **y_i**	Calculate Vapor Molecular Weight (sum Mi*yi) **M_v**	Component Weight Fraction in Vapor (M_i*y_i/M_v) **Z_{vi}**
Methane	16			
Ethane	30			
Propane	44			
Isobutane	58			
N-Butane	58			
1,3 Butadiene	54			
Isopentane	72			
N-Pentane	72			
N-Hexane	86			
Hexane	84			
Benzene	78			
Heptanes	97			
2,2,4 Trimethylpentane	114			
Toluene	92			
Octanes	111			
Ethyl Benzene	106			
Xylenes	106			
Isopropylbenzene	120			
Nonanes	123			
Naphthalene	128			
Decanes+				
y_i SUM / M_v / Z_{vi}SUM		1.00		1.00

Estimated Actual HAP Emissions – Breakout Tank
Pump Station 3

1. The TOC emissions (losses) are determined from EPA's TANKS 4.0 Program. Individual component emission rates (losses) are then determined using the vapor phase weight fractions previously determined for each component.

$$L_{Ti} = (Z_{vi})(L_T)$$

2. Based on an actual flow of crude to the breakout tank of:____________________ bbl/yr

____________________ gal/yr

The Total TOC losses from the breakout tank are: ____________________ lb/yr

____________________ TPY

Calculation of Component Emission Rates (Losses)				
Component **i**	Component Weight Fraction in Vapor **Z_{vi}**	TOC Losses (from TANKS) **L_T**	Component Emission Rate/Loss **L_{Ti}**	Total HAP Emission Rate/Losses **L_{HAP}**
Methane				N/A
Ethane				N/A
Propane				N/A
Isobutane				N/A
N-Butane				N/A
1,3 Butadiene				
Isopentane				N/A
N-Pentane				N/A
N-Hexane				
Hexane				N/A
Benzene				
Heptanes				N/A
2,2,4 Trimethylpentane				
Toluene				
Octanes				N/A
Ethyl Benzene				
Xylenes				
Isopropylbenzene				
Nonanes				N/A
Naphthalene				
Decanes+				N/A
L_{Ti} SUM / L_{HAP} SUM				

[Permit No. AQ0075CPT03, 10/28/05]
[18 AAC 50.040(j), 7/25/08; 18 AAC 50.326(j)]
[40 C.F.R. 71.6(a)]

Section 12. Visible Emissions Forms

VISIBLE EMISSIONS 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" (a copy is available in https://www3.epa.gov/ttnemc01/methods/webinar8.pdf).

- 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 visible emissions 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, note in the Comments column whether the Plume is "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 color of clouds and 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.
- Observer's Affiliation: observer's employer.
- Certifying Organization, 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	Observation Date		Start Time		End Time	
		Sec / Min	0	15	30	45	Comments
Emission Unit Location		1					
City / State / Zip		2					
Phone # (Key Contact)	Stationary Source ID Number	3					
Process Equipment	Operating Mode	4					
Control Equipment	Operating Mode	5					
Describe Emission Point/Location		6					
Height above ground level / Height relative to observer	Clinometer Reading	7					
Distance From Observer Start End	Direction From Observer Start End	8					
Describe Emissions & Color Start	End	9					
Visible Water Vapor Present? If yes, determine approximate distance from the stack exit to where the plume was read No Yes		10					
Point in Plume at Which Opacity Was Determined		11					
Describe Plume Background Start End	Background Color Start End	12					
		13					
Sky Conditions: Start	End	14					
Wind Speed Start End	Wind Direction From Start End	15					
Ambient Temperature	Wet Bulb Temp / RH percent	16					
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		17					
		18					
		19					
		20					
		21					
		22					
		23					
		24					
		25					
		26					
		27					
		28					
		29					
Additional Information:		30					
		Range of Opacity: Minimum				Maximum	
I have received a copy of these opacity observations Print Name:		Print Observer's Name					
Signature:		Observer's Signature				Date / Observer's Affiliation:	
Title	Date	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 Start	Time End		Opacity Sum	Opacity Average	Comments

Section 13. Notification Form[36]

Trans Alaska Pipeline System – Pump Station 4
Stationary Source Name

AQ0075TVP04
Air Quality Permit Number.

Alyeska Pipeline Service Company
Company Name

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[37], CO[38], or Settlement Agreement - Complete Section 2 and Certify

[36] Revised as of July 22, 2020.

[37] Compliance Order By Consent

[38] 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 (go to end of form)

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.

(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_______________________

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 75.)*

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 75).

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