MATANUSKA ELECTRIC ASSOCIATION

April 30, 2025

Alaska Department of Environmental Conservation
Air Permit Program
ATTN: Permit Intake Clerk
555 Cordova Street
Anchorage, AK 99501
DEC.AQ.Airreports@alaska.gov

Subject: Matanuska Electric Association - Eklutna Generation Station Title I Minor Permit Application

Dear Permit Intake Clerk,

Matanuska Electric Association, Inc. (MEA) submits the enclosed minor permit application for the Eklutna Generation Station (EGS). The application is classified under 18 Alaska Administrative Code (AAC) 50.508(6) to revise terms and conditions of Title I Minor Permit No. AQ1086MSS03. As a result of the requested revisions, the project will result in potential emissions of oxides of nitrogen (NO_X) that exceed the minor permit threshold in 18 AAC 50.502(c)(3)(A)(iii).

If you have any questions, please contact Traci Bradford at 907-761-9374 or by email at traci.bradford@mea.coop.

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.

Sincerely,

Joshua Crowell
EGS Senior Manager of Power Supply

cc: Tony Izzo, MEA
Tony Zellers, MEA
Traci Bradford, MEA
Jeanette Brena, Boreal Environmental Services (jbrena@boreal-services.com)

Attachment

Eklutna Generation Station

Air Quality Minor Permit Application to Revise Terms and Conditions of a Title I Permit

Prepared for:

Matanuska Electric Association, Inc.

April 2025

Eklutna Generation Station

Air Quality Minor Permit Application to Revise Terms and Conditions of a Title I Permit

Prepared for:

Matanuska Electric Association, Inc.

28705 Dena'ina Elders Road
Chugiak, AK 99567

Prepared by:

Boreal Environmental Services

4300 B St., Suite 510
Anchorage, AK 99503

SUMMARY OF REQUIRED APPLICATION ELEMENTS

Matanuska Electric Association, Inc. (MEA) requests revisions to Title I Minor Permit No. AQ1086MSS03 for Eklutna Generation Station under 18 AAC 50.508(6). As a result of the requested revisions, the project will result in potential emissions of oxides of nitrogen (NO_X) that exceed the minor permit threshold in 18 AAC 50.502(c)(3)(A)(iii). The proposed revisions will provide flexibility for MEA to operate the dual fuel-fired generator engines in diesel-fired mode at greater frequencies than currently authorized. This permit revision is necessary because MEA has been informed by its suppliers that delivery of natural gas will not be guaranteed on any upcoming contracts due to expected natural gas supply shortages. MEA requests that the Department incorporate the revisions into the Title V operating permit via the integrated review process set out by 18 AAC 50.326(c)(1).

The following table provides a summary of required elements for a minor permit under 18 AAC 50.502(c)(3) and 18 AAC 50.508(6) and shows where those elements are located in the application.

Required Application Elements

Regulatory Citation	Requirement	Application Section
18 AAC 50.502(c)(3)		
18 AAC 50.540(b)	Stationary Source Identification Form	Before Attachment A
18 AAC 50.540(c)(1)(A)	Emissions Unit Information Form	Before Attachment A
18 AAC 50.540(c)(1)(B)	Emissions Summary Form	Before Attachment A
18 AAC 50.540(c)(2)(A)	Ambient demonstration for each pollutant for which a permit is required under 18 AAC 50.502(c)(3)	Attachments C and E
18 AAC 50.508(6)		
18 AAC 50.540(b)	Stationary Source Identification Form	Before Attachment A
18 AAC 50.540(k)(1)	Copy of the Title I permit that established the permit term or condition	Attachment D
18 AAC 50.540(k)(2)	Explanation of why the permit term or condition should be revised or rescinded	Attachment B
18 AAC 50.540(k)(3)	Effect of revising or revoking the permit term or condition on emissions, other permit terms, the underlying ambient demonstration, and compliance monitoring	Attachments A, B, C, and E
18 AAC 50.540(k)(4)	Explanation of the conditions' effect on avoiding a permit classification	Attachment B

Alaska Department of Environmental Conservation
Air Quality Minor Permit Application

STATIONARY SOURCE IDENTIFICATION FORM

Section 1 Stationary Source Information

Name: Eklutna Generation Station				SIC: 4911
Project Name (if different):	Contact: Traci Bradford, Environmental Engineer			
Physical Address: 28705 Dena'ina Elders Road	City: Chugiak	State: AK		Zip: 99567
	Telephone: (907) 761-9374			
	E-Mail Address: traci.bradford@mea.coop			
UTM Coordinates (m) or Latitude/Longitude:	Northing:	Easting:	Zone:	
	Latitude: 61º 27' 35.4" N	Longitude: 149° 20' 33.9" W		

Section 2 Legal Owner

Name: Matanuska Electric Association, Inc.		
Mailing Address: P.O. Box 2929		
City: Palmer	State: AK	Zip: 99645
Telephone #:		
E-Mail Address:		

Section 3 Operator *(if different from owner)*

Name: Same as Owner		
Mailing Address:		
City:	State:	Zip:
Telephone #:		
E-Mail Address:		

Section 4 Designated Agent *(for service of process)*

Name: Joshua Crowell, Senior Manager of Power Supply		
Mailing Address: P.O. Box 2929		
City: Palmer	State: AK	Zip: 99645
Telephone #:		
E-Mail Address:		

Section 5 Billing Contact Person *(if different from owner)*

Name: Traci Bradford, Environmental Engineer		
Mailing Address: P.O. Box 2929		
City: Palmer	State: AK	Zip: 99645
Telephone #: 907-761-9374		
E-Mail Address: traci.bradford@mea.coop		

Section 6 Application Contact

Name: Traci Bradford, Environmental Engineer			
Mailing Address: P.O. Box 2929	City: Palmer	State: AK	Zip: 99645
	Telephone: 907-761-9374		
	E-Mail Address: traci.bradford@mea.coop		

Section 7 Desired Process Method *(Check only one – see 18 AAC 50.542(a) for process descriptions and restrictions)*

☐ Fast track for a permit classification under 18 AAC 50.502 [18 AAC 50.542(b)]

☒ Public comment [18 AAC 50.542(d)]

Section 8 Source Classification(s) *(Check all that apply)*

[18 AAC 50.502(b)]

- ☐ Asphalt Plant [≥ 5 ton per hour]
- ☐ Thermal Soil Remediation Unit [≥ 5 ton per hour]
- ☐ Rock Crusher [≥ 5 ton per hour]
- ☐ Incinerator(s) [total rated capacity ≥ 1000 lb/hour]
- ☐ Coal Preparation Plant
- ☐ Port of Anchorage Facility

If you checked any of the above, is (are) the emission unit(s) ☐ new, ☐ relocated*, or ☐ existing?

[18 AAC 50.502(c)(1)]

New or relocated* stationary source with potential emissions greater than:

- ☐ 40 tons per year (tpy) NOx
- ☐ 40 tpy SO_2
- ☐ 15 tpy PM-10
- ☐ 10 tpy PM-2.5
- ☐ 0.6 tpy lead
- ☐ 100 tpy CO in a nonattainment area

[18 AAC 50.502(c)(2)]

Construction or relocation* of a:

- ☐ Portable oil and gas operation
- ☐ ≥ 10 MMBtu/hr fuel burning equipment in a SO_2 special protection area

* *Relocation does NOT include moving equipment from one place to another within your current stationary source boundary.*

Section 9 Modification Classification(s) (*Check all that apply*)

[18 AAC 50.502(c)(3)]

☒	NOx Increase > 10 tpy	[and existing PTE > 40 tpy]
☐	SO_2 Increase > 10 tpy	[and existing PTE > 40 tpy]
☐	PM-10 Increase > 10 tpy	[and existing PTE > 15 tpy]
☐	PM-2.5 Increase > 10 tpy	[and existing PTE > 10 tpy]
☐	CO Increase > 100 tpy	[and existing PTE > 100 tpy in a nonattainment area]

[18 AAC 50.502(c)(4)]

☐	NOx Increase > 40 tpy	[and existing PTE ≤ 40 tpy]
☐	SO_2 Increase > 40 tpy	[and existing PTE ≤ 40 tpy]
☐	PM-10 Increase > 15 tpy	[and existing PTE ≤ 15 tpy]
☐	PM-2.5 Increase > 10 tpy	[and existing PTE ≤ 10 tpy]
☐	CO Increase > 100 tpy	[and Existing PTE ≤ 100 tpy in a nonattainment area]

Basis for calculating modification:

- ☐ Projected actual emissions minus baseline actual emissions
- ☒ New potential emissions minus existing potential emissions

Section 10 Permit Action Request (*Check all that apply*)

[18 AAC 50.508]

- ☐ Establish Plant-wide Applicability Limitation (PAL)
- ☐ Establish emission reductions to offset nonattainment pollutant
- ☐ Owner Requested Limit* (ORL)
- ☒ Revise or Rescind Title I Permit Conditions *
  Permit Number: AQ1086MSS03
  Condition Number: See attached

**Which to use? See* http://www.dec.state.ak.us/air/ap/docs/orlrtc.pdf

Section 11 Existing Permits and Limits

For an existing stationary source, do you have an existing:
(Check all that apply)

- ☒ Air quality permit Number(s)*: AQ1086TVP02
  AQ1086MSS03
- ☐ Owner Requested Limit(s) Permit Number(s):
- ☐ Pre-Approved Emission Limit (PAEL) Number(s)**:

* *All active construction, Title V, and minor permit numbers.*
***Optional. Please provide this number if possible.*
http://dec.alaska.gov/Applications/Air/airtoolsweb/

Section 12 Project Description

Provide a short narrative describing the project. Discuss the purpose for conducting this project, what emission units/activities will be added/modified under this project (i.e., project scope), and the project timeline. If the project is a modification to an existing stationary source, describe how this project will affect the existing process. Include any other discussion that may assist the Department in understanding your project or processing your application. Include a schedule of construction.

Please use additional copies of this sheet if necessary.

Matanuska Electric Association, Inc. (MEA) requests revisions to Title I Minor Permit No. AQ1086MSS03 for Eklutna Generation Station under 18 AAC 50.508(6). As a result of the requested revisions, the project will result in potential emissions of oxides of nitrogen (NO_X) that exceed the minor permit threshold in 18 AAC 50.502(c)(3)(A)(iii). The proposed revisions will provide flexibility for MEA to operate the dual fuel-fired generator engines in diesel-fired mode at greater frequencies than currently authorized. This permit revision is necessary because MEA has been informed by its suppliers that delivery of natural gas will not be guaranteed on any upcoming contracts due to expected natural gas supply shortages. MEA requests that the Department incorporate the revisions into the Title V operating permit via the integrated review process set out by 18 AAC 50.326(c)(1).

Application Information

Attachment A provides an air quality permit applicability summary for the project and provides emissions calculations.

Attachment B provides information under Section 12 of this form pertaining to revising or rescinding a Title I permit condition.

Attachment C provides the ambient demonstration (dispersion modeling analysis) as required under 18 AAC 50.540(c)(2)(A).

Attachment D provides a copy of the Title I permit that is being requested to be rescinded, as well as a copy of the Title V operating permit.

Attachment E provides supporting electronic files.

Section 12 Project Description Continued

For **PALs under Section 10** of this application, include the information listed in 40 C.F.R. 52.21(aa)(3), adopted by reference in 18 AAC 50.040 [18 AAC 50.540(h)].

Not Applicable.

For a **limit to establish offsetting emissions under Section 10** of this application, specify the physical or operational limitations necessary to provide actual emission reductions of the nonattainment air pollutant; including [18 AAC 50.540(i)]:

- A calculation of the expected reduction in actual emissions; and

Not Applicable.

- The emission limitation representing that quantity of emission reduction.

Not Applicable.

Section 12 Project Description Continued

For **ORLs under Section 10** of this application [18 AAC 50.540(j)], include:

A description of each proposed limit, including for each air pollutant a calculation of the effect the limit will have on the stationary source's potential to emit and the allowable emissions [18 AAC 50.225(b)(4)];

Not Applicable.

A description of a verifiable method to attain and maintain each limit, including monitoring and recordkeeping requirements [18 AAC 50.225(b)(5)];

Not Applicable.

Citation to each requirement that the person seeks to avoid, including an explanation of why the requirement would apply in the absence of the limit and how the limit allows the person to avoid the requirement [18 AAC 50.225(b)(6)];

Not Applicable.

A statement that the owner or operator of the stationary source will be able to comply with each limit [18 AAC 50.225(b)(8)];

Not Applicable.

Section 12 Project Description Continued

For **revising or rescinding Title I permit conditions under Section 10** of this application [18 AAC 50.540(k)], include:

An explanation of why the permit term or condition should be revised or rescinded [18 AAC 50.540(k)(2)];

See Attachment B.

The effect of revising or revoking the permit term or condition on [18 AAC 50. 540 (k)(3)]:

- Emissions;

See Attachments A and B.

- Other permit terms;

See Attachment B.

- The underlying ambient demonstration, if any;

See Attachments B, C and E.

- Compliance monitoring; and

See Attachment B.

For revising a condition that allows avoidance of a permit classification, the information required for that type of permit, unless the revised condition would also allow the owner or operator to avoid the classification. [18 AAC 50.540(k)(4)]

See Attachment B.

Section 13 Other Application Material

The information listed below must be included in your air quality control minor permit application. *Note: These must be attached in order for your application to be complete.*

If required to submit an analysis of ambient air quality under 18 AAC 50.540(c)(2), or if otherwise requested by the Department:

☒ Attached are maps, plans, and/or aerial photographs as necessary to show the locations and distances of
- emissions units, buildings, emitting activities and boundaries of the associated with the stationary source, and
- nearby or adjacent residences, roads, other occupied structures and general topography within 15 kilometers.

(Indicate compass direction and scale on each.)

☒ Attached is a document (e.g., spreadsheet) showing coordinates and elevations of each modeled unit, along with parameters necessary to characterize each unit for dispersion modeling.

☒ Attached is an electronic copy of all modeling files.

Section 14 Certification

This certification applies to the Air Quality Control Minor Permit Application for the Eklutna Generation Station (Stationary Source Name) submitted to the Department on: See date below.

Type of Application

☒ Initial Application
☐ Change to Initial Application

The application is **NOT** complete unless the certification of truth, accuracy, and completeness on this form bears the signature of a **Responsible Official**. Responsible Official is defined in 18 AAC 50.990. (18 AAC 50.205)

CERTIFICATION OF TRUTH, ACCURACY, AND COMPLETENESS

"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."

Signature: [signature]	Date: 4/30/2025
Printed Name: Joshua Crowell	Title: Senior Manager of Power Supply

Section 15 Attachments

☒ Attachments Included.
List attachments:
- Attachment A – Emissions Unit Information and Potential to Emit Calculations
- Attachment B – Revise or Rescind Title I Permit Conditions
- Attachment C – Ambient Demonstration
- Attachment D – Permits
- Attachment E – Electronic Files

Section 16 Mailing Address

Submit the minor permit application to the Permit Intake Clerk in the Department's Anchorage office. Submitting to a different office will delay processing. The mailing address and phone number for the Anchorage office is:

Permit Intake Clerk
Alaska Department of Environmental Conservation
Air Permit Program
555 Cordova Street
Anchorage, Alaska 99501
(907) 269-6881

Alaska Department of Environmental Conservation
Air Quality Control Minor Permit Application

MINOR PERMIT APPLICATION – EMISSION UNIT INFORMATION

FOR A NEW STATIONARY SOURCE: Complete this form for all emissions units.

FOR A MODIFICATION TO AN EXISTING STATIONARY SOURCE:
IF YOU HAVE A TITLE V PERMIT: Complete this form for each emissions unit that is new or that is affected by a physical change or change in the method of operation.
IF YOU DO NOT HAVE A TITLE V PERMIT or APPLICATION CLASSIFIED UNDER 18 AAC 50.508(5): Complete this form for all emissions units.

Section 1 Stationary Source Information

Stationary Source Name: Eklutna Generation Station

Section 2 Emissions Unit (EU) Identification (ID) and Description

Note: Do not use this section for emission units associated with asphalt plants, soil remediation, and rock crushers. Use the Supplementary Forms for these units.

EU ID No.	Description	Construction Date	Make / Model	Serial No.	Requested Limit* (specify units)	Max. Rated Capacity or Design Throughput
1-10	Generator Engines	March 2012	Wartsila 18V50DF	N/A	Modify Condition 5 of AQ1086MSS03 to change the hour limit when burning ULSD to NO_X and PM_{10} emissions limits (see Attachment B)	17.1 MW, each

**If no annual limit is applicable (e.g., hours, fuel), then specify not applicable (N/A).*
Please use additional copies of this sheet if necessary.

Have you identified each emission unit (if you do not have a Title V permit), or each new or affected emission unit (if you have an existing Title V permit) in Section 2 above? ☒ Yes ☐ No
If not, please explain:

Each affected unit is identified.

Section 3 Emissions Unit Use

EU ID No.	Is unit portable?		Is the unit:						Is this unit a:		If limited operation, is the unit:		
[List same EUs as in Section 2.]	Yes	No	a nonroad engine? Yes	No	an intermittently used oil field support equipment per Policy 04.02.105? Yes	No	an oil field construction unit per Policy 04.02.104? Yes	No	primary (base load) unit?	or limited operation unit?	emergency or black start unit?	subject to a permit limit?	or other (specify)?
1-10	☐	☒	☐	☒	☐	☒	☐	☒	☒	☐	☐	☒	☐

Please use additional copies of this sheet if necessary.

Have you specified the use of each emission unit in Section 3 above? ☒ Yes ☐ No

If not, please explain:

EU IDs 1-10 are currently subject to an hour limit when burning ULSD in Condition 5 of AQ1086MSS03; requesting to change to NO_X and PM_{10} emissions limits (see Attachment B).

Section 4 Fuel Information

Complete Section 4a or 4b for each emissions unit, as appropriate.

Section 4a Fuel Burning Equipment not Including Flares

EU ID No.	Fuel type(s)	Maximum fuel sulfur content	Fuel density (lb/gal) (if liquid fuel)	Higher heating value*	Maximum fuel consumption rate (gallons/hour or MMscf/hour)
1-10	NG	20 ☐ wt. % S ☒ ppmv H_2S	N/A	1,020 ☐ Btu/gal ☒ Btu/dscf	0.130 MMscf/hr w/ 13.1 gal/hr ULSD, each
	ULSD	0.0015 ☒ wt. % S ☐ ppmv H_2S	6.9 lb/gal	138,000 ☒ Btu/gal ☐ Btu/dscf	1,114.6 gal/hr, each

**Use British thermal unit (Btu) per gallon (gal) for liquid fuels. Use Btu per dry standard cubic foot (dscf) for gaseous fuels.*
Please use additional copies of this sheet if necessary.

Include additional notes as warranted.

EU IDs 1-10 are dual fuel-fired; when operating on NG, units burn 1 percent ULSD.

Have you provided the fuel details for each fuel-burning emission unit (excluding flares) in Section 4a above? ☒ Yes ☐ No

If not, please explain:

EU IDs 1-10 are dual fuel-fired; when operating on NG, units burn 1 percent ULSD.

Section 4b Flares
Complete this section if the project/stationary source contains a flare.

Do you own or operate a flare? ☐ Yes ☒ No *(If not skip this section)*

EU ID No:	Heat release rate for pilot / purge operation (MMBtu/hr)	Maximum heat release rate (MMBtu/hr)	Flare gas heat content (Btu/scf)	Flare gas H_2S content (ppmv)
N/A				

Please use additional copies of this sheet if necessary.

Include additional notes as warranted.

Have you provided the fuel use details for all flares in Section 4b above? ☐ Yes ☐ No
If not, please explain:

Section 5 Materials Processed and Methods of Operation

Complete this section if the project/stationary source contains a materials-handling process.

Does your project contain a materials-handling process? ☐ Yes ☒ No *(If not skip this section)*

EU ID No.	Materials processed	Maximum material processing rate	Describe method of operation
N/A			

Please use additional copies of this sheet if necessary.

Include additional notes as warranted.

Have you specified the material processing details in Section 5 above? ☐ Yes ☐ No

If not, please explain:

Section 6 Emission Control Information (if applicable)

Complete this section if the project/stationary source contains emission control equipment.

Do you own or operate emission control equipment? ☒ Yes ☐ No *(If not, note below and skip this section.)*

EU ID No.	Control equipment	Pollutant(s) controlled:	Description of the control equipment	Description of significant operating parameters and set points for the control equipment	The control equipment is necessary:		
					To comply with an emission standard	To avoid a project classification	Other – give purpose of control equipment
1-10	SCR	NO_X	Selective Catalytic Reduction	Refer to Condition 8 of AQ1086MSS03	☐	☒	
	CATOX	CO, VOCs, HAPs	Catalytic Oxidation		☐	☒	

Please use additional copies of this sheet if necessary.

Include additional notes as warranted.

Have you specified the details of any emission controls in Section 6 above? ☒ Yes ☐ No

If not, please explain:

Section 7 Emission Factors

Give exact citations of emission factor sources.

EU ID No.	Emission Factors								
	NOx	CO	PM-2.5	PM-10	PM	SO_2	VOC	HAPs	Lead
1-10 (NG/ULSD)	3.43 lb/hr	4.52 lb/hr	4.89 lb/hr	4.89 lb/hr	4.89 lb/hr	20 ppmv H_2S	3.43 lb/hr	See spreadsheet	See spreadsheet
1-10 (ULSD)	19.95 lb/hr	6.78 lb/hr	10.92 lb/hr	10.92 lb/hr	10.92 lb/hr	15 ppmw S	7.91 lb/hr	See spreadsheet	See spreadsheet

EU ID No.	Sources and References for Emission Factors								
	NOx	CO	PM-2.5	PM-10	PM	SO_2	VOC	HAPs	Lead
1-10 (NG/ULSD)	Vendor Data	Vendor Data	Vendor Data	Vendor Data	Vendor Data	Mass Balance	Vendor Data	See spreadsheet	See spreadsheet
1-10 (ULSD)	Vendor Data	Vendor Data	Vendor Data	Vendor Data	Vendor Data	Mass Balance	Vendor Data	See spreadsheet	See spreadsheet

Please use additional copies of this sheet if necessary.

Include additional notes as warranted.

EU IDs 1-10 are dual fuel-fired; when operating on NG, units burn 1 percent ULSD.

Have you specified all emission factors and reference sources in Section 7 above? ☒ Yes ☐ No

If not, please explain:

Section 8 Applicable State Emission Limits (listed in 18 AAC 50.050 through 18 AAC 50.090)

Complete this section for emissions units that are new or are affected by the physical change or change in operation.

EU ID No.	Emission Limit or Standard	Regulation Citation	Compliance Method
1-10	Visible Emissions, excluding condensed water vapor, from an industrial process or fuel burning equipment may not reduce visibility through the exhaust effluent by more than 20 percent averaged over any six minutes.	18 AAC 50.055(a)(1)	Refer to Condition 1.3 of AQ1086TVP02.
1-10	Particulate matter emitted from an industrial process or fuel burning equipment may not 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)	Refer to Condition 5.3 of AQ1086TVP02.
1-10	Sulfur-compound emissions, expressed as sulfur dioxide, from an industrial process or from fuel burning equipment may not exceed 500 ppm averaged over three hours.	18 AAC 50.055(c)(1)	Refer to Conditions 10 and 11 of AQ1086TVP02.

Please use additional copies of this sheet if necessary.

Have you specified all applicable state emission limits in Section 8 above? ☒ Yes ☐ No

Have you specified a demonstration of compliance for each emission limit or standard? ☒ Yes ☐ No

If you answered "no" to either question, please explain:

EU IDs 1-10 are not new emissions unit and are not affected by a physical change or change in the method of operation.

Section 9 Incinerators

Complete this section if the project/stationary source contains an incinerator.

Do you own or operate an incinerator? ☐ Yes ☒ No *(If not, skip this section.)*

EU ID No.	Fuels Burned (type and consumption rate)	Rated capacity in pounds per hour	Type of waste burned
N/A			

Please use additional copies of this sheet if necessary.

Include additional notes as warranted.

Have you specified the details of all incinerators in Section 9 above? ☐ Yes ☐ No

If not, please explain:

Alaska Department of Environmental Conservation
Air Quality Control Minor Permit Application

EMISSIONS SUMMARY FORM
Modification of an Existing Stationary Source

Section 1 Stationary Source Information

Stationary Source Name: Eklutna Generation Station

Section 2 Existing Potential to Emit (PTE) for the Entire Stationary Source BEFORE the Modification

EU ID No.	*Does project affect the emissions unit?*	PTE (tpy)								
		CO	NOx[4]	PM-2.5[1]	PM-10[1]	PM	SO_2	VOC[2]	Fugitive VOC[3]	Fugitive PM[3]
1-10	☒ Yes ☐ No	199.8	164.1	219.4	219.4	219.4	20.3	154.1	0.0	0.0
11	☐ Yes ☒ No	0.1	0.3	1.1E-2	1.1E-2	1.1E-2	5.3E-4	1.1E-2	0.0	0.0
12 & 18	☐ Yes ☒ No	1.1	8.5	0.3	0.3	0.3	7.4E-3	0.2	0.0	0.0
13 & 14	☐ Yes ☒ No	5.0	11.8	0.9	0.9	0.9	0.5	0.6	0.0	0.0
17	☐ Yes ☒ No	1.3	3.3	0.2	0.2	0.2	0.1	0.9	0.0	0.0
Tanks	☐ Yes ☒ No	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
Total tons per year (tpy)		**207.3**	**188.1**	**220.9**	**220.9**	**220.9**	**21.0**	**155.8**	**0.0**	**0.0**

☒ Detailed Excel spreadsheet emissions calculations are attached. *These must be attached in order for your application to be complete. Include multiple copies of this page if more space is required.*

☐ *Check this box if fugitive emissions are included in permit applicability under 18 AAC 50.502(i).*

Brief description of why fugitive emissions are included in permit applicability:

Notes:
1 Include condensable particulate matter for PM-10 and PM-2.5.
2 If total PTE for volatile organic compounds (VOCs) is at least 10 tpy, include a separate Excel spreadsheet that shows the HAP emissions.
3 Fugitive VOC and PM emissions are included as assessable emissions regardless of permit applicability.
4 Fugitive NOx emissions from blasting should be included in the PTE column for NOx.

Have you completed Section 2 above? ☒ Yes ☐ No
If not, please explain:

Existing PTE for stationary source before modification is from the SOB for AQ1086TVP02.

Section 3 Change in Emissions

Show ONLY existing emissions units that are affected by the project. Show EITHER the change in actual emissions (Sections 3a and 3b) OR the change in potential emissions (Sections 2 and 3c).

Section 3a Actual Emissions – NOx, CO, PM-2.5, PM-10, PM, SO_2 (18 AAC 50.502(c)(3)(B) or 18 AAC 50.508(5))

If an existing emissions unit is being removed, enter zero for "projected actual emissions" for that unit.

See 18 AAC 50.502 for directions on calculating "baseline actual emissions" and "projected actual emissions."

EU ID No.	Type of Modification		Baseline Actual Emissions (tpy)					Projected Actual Emissions (tpy)				
	Modified EU	Removed EU	CO	NOx	PM-2.5[1]	PM-10[1]	SO_2	CO	NOx	PM-2.5[1]	PM-10[1]	SO_2
	☐	☐										
	☐	☐										
	☐	☐										
	☐	☐										
	☐	☐										
Total												

Use this table only if the project does not include new emission units. See 18 AAC 50.502(e) and (h)(4)

☐ Detailed Excel spreadsheets emissions calculations are attached. *These must be attached in order for your application to be complete. You may give an example calculation where the method of calculation is identical for multiple emissions units.*

Notes:

1 Include condensable particulate matter for PM-10 and PM-2.5.

Section 3b Change in Actual Emissions (18 AAC 50.502(c)(3)(B) or 18 AAC 50.502(c)(4)(B))

If you choose actual emissions as your basis, complete Sections 3a and 3b for each emissions unit for which you answered "YES" in Section 2. Change in actual emissions = "projected actual emissions" minus "baseline actual emissions" from Section 3a.

EU ID No.	Change in Actual Emissions (tpy)				
	CO	NOx	PM-2.5[1]	PM-10[1]	SO_2
Total					

Use this table only if the project does not include new emission units. See 18 AAC 50.502(e) and (h)(4)

1 Include condensable particulate matter for PM-10 and PM-2.5.

Have you completed Section 3a and 3b above? ☐ Yes ☒ No
If not, please explain:

Opted to use change in potential emissions.

Section 3c Change in Potential to Emit (PTE) (18 AAC 50.502(c)(3)(A) or 18 AAC 50.502(c)(4)(A))

If you choose PTE as your basis for calculation, complete this section for each emissions unit that is new and for each emissions unit for which you answered "YES" in Section 2.

Under "PTE AFTER the Modification", enter zero if you are removing the emissions unit.

Under "Change in PTE":
For each EXISTING emissions unit, subtract the amount of PTE BEFORE Modification in Section 2 from the "PTE AFTER the Modification"
For each NEW emissions unit, enter the amount from "PTE AFTER the Modification."

EU ID No.	**PTE - AFTER the Modification (tpy)** [only from modified and new emissions units. Do not list emission units for which you answered "NO" in Section 2.]								**Change in PTE (tpy)**							
	CO	**NO_X**	**PM-2.5[1]**	**PM-10[1]**	**PM**	**SO_2**	**VOC**	**HAPs[2]**	**CO**	**NO_X**	**PM-2.5[1]**	**PM-10[1]**	**PM**	**SO_2**	**VOC**	**HAPs**
1-10	207.4	220.0	220.0	220.0	220.0	20.3	169.2	16.0	7.7	55.8	0.5	0.5	0.5	0.0	15.4	0.5

Include multiple copies of this page if more space is required.
☒ Detailed Excel spreadsheet emissions calculations are attached. *These must be attached for your application to be complete.*
Notes:
1 Include condensable particulate matter for PM-10 and PM-2.5
2 If the total PTE for hazardous air pollutants (HAPs) for the entire stationary source is at least 10 tpy, include a separate Excel spreadsheet that shows the HAP emissions.

Have you completed all portions of Section 3c above? ☒ Yes ☐ No
If not, please explain:

Change in HAP emissions is only from adding additional HAPs missing from AQ1086TVP02.

Attachment A

Emissions Unit Information and Potential to Emit Calculations

Table A-1. Permit Applicability
Matanuska Electric Association - Eklutna Generation Station

Pollutant	Existing Stationary Source Potential Emissions[1]	Proposed Stationary Source Potential Emissions	Proposed Emissions Increase	Minor Permit Applicability Threshold[2]	Minor Permit Required?	PSD Permit Applicability Threshold[3]	PSD Permit Required?
NO_X	188.1 tpy	243.9 tpy	55.8 tpy	10 tpy	Yes	250 tpy	No
CO	207.3 tpy	215.0 tpy	7.7 tpy	----[4]	----	250 tpy	No
PM	220.9 tpy	221.4 tpy	0.5 tpy	----	----	250 tpy	No
PM_{10}	220.9 tpy	221.4 tpy	0.5 tpy	10 tpy	No	250 tpy	No
$PM_{2.5}$	220.9 tpy	221.4 tpy	0.5 tpy	10 tpy	No	250 tpy	No
SO_2	21.0 tpy	21.0 tpy	0.0 tpy	40 tpy	No	250 tpy	No
VOC	155.8 tpy	171.2 tpy	15.4 tpy	----	----	250 tpy	No
GHGs	720,229 tpy	753,909.4 tpy	33,680.4 tpy	----	----	----	----
HAPs	15.8 tpy	16.3 tpy	0.5 tpy	----	----	----	----

Notes:

1. Per Statement of Basis for Title V Operating Permit No. AQ1086TVP02.
2. Minor air permit thresholds for an existing stationary source as listed in 18 AAC 50.502(c)(3) and 18 AAC 50.502(c)(4), as applicable.
3. PSD permit thresholds in 40 CFR 52.21(b)(1)(i)(b).
4. Not applicable.

Table A-2. Emission Unit Inventory
Matanuska Electric Association - Eklutna Generation Station

ID	Emission Unit Name	Emission Unit Description	Size / Rating	Fuel Type	Maximum Rated Fuel Consumption	Maximum Allowable Operations
Significant Emission Units						
1	Generator Engine	Wartsila 18V50DF	17.1 MW	NG / ULSD	129,548 scf/hr	8,760 hr/yr
2	Generator Engine	Wartsila 18V50DF	17.1 MW	NG / ULSD	129,548 scf/hr	8,760 hr/yr
3	Generator Engine	Wartsila 18V50DF	17.1 MW	NG / ULSD	129,548 scf/hr	8,760 hr/yr
4	Generator Engine	Wartsila 18V50DF	17.1 MW	NG / ULSD	129,548 scf/hr	8,760 hr/yr
5	Generator Engine	Wartsila 18V50DF	17.1 MW	NG / ULSD	129,548 scf/hr	8,760 hr/yr
6	Generator Engine	Wartsila 18V50DF	17.1 MW	NG / ULSD	129,548 scf/hr	8,760 hr/yr
7	Generator Engine	Wartsila 18V50DF	17.1 MW	NG / ULSD	129,548 scf/hr	8,760 hr/yr
8	Generator Engine	Wartsila 18V50DF	17.1 MW	NG / ULSD	129,548 scf/hr	8,760 hr/yr
9	Generator Engine	Wartsila 18V50DF	17.1 MW	NG / ULSD	129,548 scf/hr	8,760 hr/yr
10	Generator Engine	Wartsila 18V50DF	17.1 MW	NG / ULSD	129,548 scf/hr	8,760 hr/yr
1-10 (combined)	Generator Engines	Wartsila 18V50DF	17.1 MW (each)	ULSD Exclusively	1,114.6 gal/hr (each)	See Table A-12
11	Firewater Pump Engine	John Deere JU6H-UFADN0	197 hp	ULSD	10.3 gal/hr	500 hr/yr
12	Black Start Generator Engine	Cummins 1000DQFAD	1,490 hp	ULSD	71.9 gal/hr	1,000 hr/yr
18	Black Start Generator Engine	Cummins 1000DQFAD	1,490 hp	ULSD	71.9 gal/hr	
13	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	15.75 MMBtu/hr	NG	15,752 scf/hr	8,760 hr/yr
14	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	15.75 MMBtu/hr	NG	15,752 scf/hr	8,760 hr/yr
13-14 (combined)	Auxiliary Boilers	Cleaver-Brooks FLX200-1650	15.75 MMBtu/hr (each)	ULSD	110.3 gal/hr (each)	1,000 hr/yr
17	Natural Gas Fuel Heater	Aether C5-G30	8.3 MMBtu/hr	NG	8,137 scf/hr	8,760 hr/yr
Insignificant Emission Units						
15	Diesel Storage Tank	Rockford 071301	509,000 gal	N/A	N/A	8,760 hr/yr
16	Diesel Storage Tank	Rockford 071301	509,000 gal	N/A	N/A	8,760 hr/yr
N/A	Lube Oil Storage Tank	Lube Oil Storage Tank	18,784 gal	N/A	N/A	8,760 hr/yr
N/A	Used Lube Oil Storage Tank	Used Lube Oil Storage Tank	14,898 gal	N/A	N/A	8,760 hr/yr
N/A	Service Lube Oil Storage Tank (2)	Service Lube Oil Storage Tank (2)	19,474 gal (each)	N/A	N/A	8,760 hr/yr
N/A	Wastewater/Lube Oil Storage Tank	Wastewater/Lube Oil Storage Tank	14,898 gal	N/A	N/A	8,760 hr/yr
N/A	Diesel Storage Tank (2)	Diesel Storage Tank (2)	1,000 gal (each)	N/A	N/A	8,760 hr/yr
N/A	Diesel Storage Tank	Diesel Storage Tank	300 gal	N/A	N/A	8,760 hr/yr
N/A	Diesel Storage Tank (2)	Diesel Storage Tank (2)	660 gal (each)	N/A	N/A	8,760 hr/yr
N/A	Diesel Engine Lube Oil Reservoirs (10)	Diesel Engine Lube Oil Reservoirs (10)	3,500 gal (each)	N/A	N/A	8,760 hr/yr

Notes:

1. NG is natural gas; ULSD is ultra low sulfur diesel; when operating on NG, EU IDs 1-10 burn one percent ULSD.

Table A-3. Oxides of Nitrogen (NO_X) Emissions
Matanuska Electric Association - Eklutna Generation Station

ID	Emission Unit Name	Rating / Capacity	Fuel Type	Proposed Operations for Maximum NO_X Emissions	NO_X Emission Factor	Reference	Proposed NO_X Emissions
Significant Emission Units							
1	Generator Engine	17.1 MW	NG / ULSD	Variable	3.43 lb/hr	Manufacturer Data	220.00 tpy
2	Generator Engine	17.1 MW	NG / ULSD		3.43 lb/hr	Manufacturer Data	
3	Generator Engine	17.1 MW	NG / ULSD		3.43 lb/hr	Manufacturer Data	
4	Generator Engine	17.1 MW	NG / ULSD		3.43 lb/hr	Manufacturer Data	
5	Generator Engine	17.1 MW	NG / ULSD		3.43 lb/hr	Manufacturer Data	
6	Generator Engine	17.1 MW	NG / ULSD		3.43 lb/hr	Manufacturer Data	
7	Generator Engine	17.1 MW	NG / ULSD		3.43 lb/hr	Manufacturer Data	
8	Generator Engine	17.1 MW	NG / ULSD		3.43 lb/hr	Manufacturer Data	
9	Generator Engine	17.1 MW	NG / ULSD		3.43 lb/hr	Manufacturer Data	
10	Generator Engine	17.1 MW	NG / ULSD		3.43 lb/hr	Manufacturer Data	
1-10 (combined)	Generator Engines	17.1 MW (each)	ULSD Exclusively		19.95 lb/hr	Manufacturer Data	
11	Firewater Pump Engine	197 hp	ULSD	500 hr/yr	2.7 g/hp-hr	Manufacturer Data	0.29 tpy
12	Black Start Generator Engine	1,490 hp	ULSD	1,000 hr/yr (combined)	5.20 g/hp-hr	Manufacturer Data	8.54 tpy
18	Black Start Generator Engine	1,490 hp	ULSD		5.20 g/hp-hr	Manufacturer Data	
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	8,260 hr/yr	1.30 lb/hr	Manufacturer Data	5.36 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	8,260 hr/yr	1.30 lb/hr	Manufacturer Data	5.36 tpy
13-14 (combined)	Auxiliary Boilers	15.75 MMBtu/hr (each)	ULSD	1,000 hr/yr (combined)	2.18 lb/hr	Manufacturer Data	1.09 tpy
17	Natural Gas Fuel Heater	8.3 MMBtu/hr	NG	8,760 hr/yr	0.09 lb/MMBtu	Manufacturer Data	3.31 tpy
						Subtotal:	**243.95 tpy**
Insignificant Emission Units							
15	Diesel Storage Tank	509,000 gal	N/A	8,760 hr/yr	N/A	N/A	0 tpy
16	Diesel Storage Tank	509,000 gal	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Lube Oil Storage Tank	18,784 gal	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Used Lube Oil Storage Tank	14,898 gal	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Service Lube Oil Storage Tank (2)	19,474 gal (each)	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Wastewater/Lube Oil Storage Tank	14,898 gal	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Diesel Storage Tank (2)	1,000 gal (each)	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Diesel Storage Tank	300 gal	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Diesel Storage Tank (2)	660 gal (each)	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Diesel Engine Lube Oil Reservoirs (10)	3,500 gal (each)	N/A	8,760 hr/yr	N/A	N/A	0 tpy
						Subtotal:	**0.00 tpy**
						Total NO_X Emissions:	**243.95 tpy**

Notes:

1. Requesting that the hour limit on ULSD fuel in Condition 5 of Permit No. AQ1086MSS03 be changed to NO_X and PM_{10} emission limits for EU IDs 1-10.
2. Emissions calculations are based on worst case scenario for dual fuel-fired units, EU IDs 13 and 14.
3. EU IDs 1-10 undergo annual source testing for NO_X, CO, and VOC when burning NG per 40 CFR 60 Subpart JJJJ (two units per year per custom monitoring waiver); manufacturer data is used as worst-case.
4. If EU IDs 1-10 burn 2% or more ULSD on a total energy basis in a year, the engines will have to comply with 40 CFR 60 Subpart IIII (in lieu of Subpart JJJJ) for the subsequent year and conduct annual testing for NO_X and PM when burning ULSD.

Table A-4. Carbon Monoxide (CO) Emissions

Matanuska Electric Association - Eklutna Generation Station

ID	Emission Unit Name	Rating / Capacity	Fuel Type	Proposed Operations for Maximum CO Emissions	CO Emission Factor	Reference	Proposed CO Emissions
Significant Emission Units							
1	Generator Engine	17.1 MW	NG / ULSD	7,916 hr/yr	4.52 lb/hr	Manufacturer Data	17.88 tpy
2	Generator Engine	17.1 MW	NG / ULSD	7,916 hr/yr	4.52 lb/hr	Manufacturer Data	17.88 tpy
3	Generator Engine	17.1 MW	NG / ULSD	7,916 hr/yr	4.52 lb/hr	Manufacturer Data	17.88 tpy
4	Generator Engine	17.1 MW	NG / ULSD	7,916 hr/yr	4.52 lb/hr	Manufacturer Data	17.88 tpy
5	Generator Engine	17.1 MW	NG / ULSD	7,916 hr/yr	4.52 lb/hr	Manufacturer Data	17.88 tpy
6	Generator Engine	17.1 MW	NG / ULSD	7,916 hr/yr	4.52 lb/hr	Manufacturer Data	17.88 tpy
7	Generator Engine	17.1 MW	NG / ULSD	7,916 hr/yr	4.52 lb/hr	Manufacturer Data	17.88 tpy
8	Generator Engine	17.1 MW	NG / ULSD	7,916 hr/yr	4.52 lb/hr	Manufacturer Data	17.88 tpy
9	Generator Engine	17.1 MW	NG / ULSD	7,916 hr/yr	4.52 lb/hr	Manufacturer Data	17.88 tpy
10	Generator Engine	17.1 MW	NG / ULSD	7,916 hr/yr	4.52 lb/hr	Manufacturer Data	17.88 tpy
1-10 (combined)	Generator Engines	17.1 MW (each)	ULSD Exclusively	8,440 hr/yr (combined)	6.78 lb/hr	Manufacturer Data	28.61 tpy
11	Firewater Pump Engine	197 hp	ULSD	500 hr/yr	0.9 g/hp-hr	Manufacturer Data	0.10 tpy
12	Black Start Generator Engine	1,490 hp	ULSD	1,000 hr/yr (combined)	0.66 g/hp-hr	Manufacturer Data	1.08 tpy
18	Black Start Generator Engine	1,490 hp	ULSD		0.66 g/hp-hr	Manufacturer Data	
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	8,760 hr/yr	0.58 lb/hr	Manufacturer Data	2.52 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	8,760 hr/yr	0.58 lb/hr	Manufacturer Data	2.52 tpy
13-14 (combined)	Auxiliary Boilers	15.75 MMBtu/hr (each)	ULSD	0 hr/yr (combined)	0.56 lb/hr	Manufacturer Data	0 tpy
17	Natural Gas Fuel Heater	8.3 MMBtu/hr	NG	8,760 hr/yr	0.037 lb/MMBtu	Manufacturer Data	1.35 tpy
						Subtotal:	**214.98 tpy**
Insignificant Emission Units							
15	Diesel Storage Tank	509,000 gal	N/A	8,760 hr/yr	N/A	N/A	0 tpy
16	Diesel Storage Tank	509,000 gal	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Lube Oil Storage Tank	18,784 gal	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Used Lube Oil Storage Tank	14,898 gal	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Service Lube Oil Storage Tank (2)	19,474 gal (each)	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Wastewater/Lube Oil Storage Tank	14,898 gal	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Diesel Storage Tank (2)	1,000 gal (each)	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Diesel Storage Tank	300 gal	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Diesel Storage Tank (2)	660 gal (each)	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Diesel Engine Lube Oil Reservoirs (10)	3,500 gal (each)	N/A	8,760 hr/yr	N/A	N/A	0 tpy
						Subtotal:	**0.00 tpy**
						Total CO Emissions:	**214.98 tpy**

Notes:

1. Emissions calculations are based on worst case scenario for dual fuel-fired units; see Table A-12 for EU IDs 1-10.

2. EU IDs 1-10 undergo annual source testing for NO_X, CO, and VOC when burning NG per 40 CFR 60 Subpart JJJJ (two units per year per custom monitoring waiver); manufacturer data is used as worst-case.

Table A-5. Particulate Matter (PM, PM_{10}, $PM_{2.5}$) Emissions
Matanuska Electric Association - Eklutna Generation Station

ID	Emission Unit Name	Rating / Capacity	Fuel Type	Proposed Operations for Maximum PM Emissions	PM Emission Factor	Reference	Proposed PM Emissions
Significant Emission Units							
1	Generator Engine	17.1 MW	NG / ULSD	Variable	4.89 lb/hr	Manufacturer Data	220.00 tpy
2	Generator Engine	17.1 MW	NG / ULSD		4.89 lb/hr	Manufacturer Data	
3	Generator Engine	17.1 MW	NG / ULSD		4.89 lb/hr	Manufacturer Data	
4	Generator Engine	17.1 MW	NG / ULSD		4.89 lb/hr	Manufacturer Data	
5	Generator Engine	17.1 MW	NG / ULSD		4.89 lb/hr	Manufacturer Data	
6	Generator Engine	17.1 MW	NG / ULSD		4.89 lb/hr	Manufacturer Data	
7	Generator Engine	17.1 MW	NG / ULSD		4.89 lb/hr	Manufacturer Data	
8	Generator Engine	17.1 MW	NG / ULSD		4.89 lb/hr	Manufacturer Data	
9	Generator Engine	17.1 MW	NG / ULSD		4.89 lb/hr	Manufacturer Data	
10	Generator Engine	17.1 MW	NG / ULSD		4.89 lb/hr	Manufacturer Data	
1-10 (combined)	Generator Engines	17.1 MW (each)	ULSD Exclusively		10.92 lb/hr	Manufacturer Data	
11	Firewater Pump Engine	197 hp	ULSD	500 hr/yr	0.1 g/hp-hr	Manufacturer Data	0.01 tpy
12	Black Start Generator Engine	1,490 hp	ULSD	1,000 hr/yr (combined)	0.19 g/hp-hr	Manufacturer Data	0.31 tpy
18	Black Start Generator Engine	1,490 hp	ULSD		0.19 g/hp-hr	Manufacturer Data	
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	8,260 hr/yr	0.10 lb/hr	Manufacturer Data	0.39 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	8,260 hr/yr	0.10 lb/hr	Manufacturer Data	0.39 tpy
13-14 (combined)	Auxiliary Boilers	15.75 MMBtu/hr (each)	ULSD	1,000 hr/yr (combined)	0.32 lb/hr	Manufacturer Data	0.16 tpy
17	Natural Gas Fuel Heater	8.3 MMBtu/hr	NG	8,760 hr/yr	0.0048 lb/MMBtu	Manufacturer Data	0.17 tpy
						Subtotal:	**221.44 tpy**
Insignificant Emission Units							
15	Diesel Storage Tank	509,000 gal	N/A	8,760 hr/yr	N/A	N/A	0 tpy
16	Diesel Storage Tank	509,000 gal	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Lube Oil Storage Tank	18,784 gal	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Used Lube Oil Storage Tank	14,898 gal	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Service Lube Oil Storage Tank (2)	19,474 gal (each)	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Wastewater/Lube Oil Storage Tank	14,898 gal	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Diesel Storage Tank (2)	1,000 gal (each)	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Diesel Storage Tank	300 gal	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Diesel Storage Tank (2)	660 gal (each)	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Diesel Engine Lube Oil Reservoirs (10)	3,500 gal (each)	N/A	8,760 hr/yr	N/A	N/A	0 tpy
						Subtotal:	**0.00 tpy**
						Total PM Emissions:	**221.44 tpy**

Notes:

1. Requesting that the hour limit on diesel fuel in Condition 5 of Permit No. AQ1086MSS03 be changed to NO_X and PM_{10} emission limits for EU IDs 1-10.
2. Emissions calculations are based on worst case scenario for dual fuel-fired units, EU IDs 13 and 14.
3. EU IDs 1-10 had a one-time source test for PM when burning NG per Permit No. AQ1086MSS02; manufacturer data is used as worst-case.
4. If EU IDs 1-10 burn 2% or more ULSD on a total energy basis in a year, the engines will have to comply with 40 CFR 60 Subpart IIII (in lieu of Subpart JJJJ) for the subsequent year and conduct annual testing for NO_X and PM when burning ULSD.

Table A-6. Sulfur Dioxide (SO_2) Emissions

Matanuska Electric Association - Eklutna Generation Station

ID	Emission Unit Name	Rating / Capacity	Fuel Type	Proposed Operations for Maximum SO_2 Emissions	Maximum Rated Fuel Consumption	SO_2 Emission Factor	Reference	Proposed SO_2 Emissions
Significant Emission Units								
1	Generator Engine	17.1 MW	NG	8,760 hr/yr	129,548 scf/hr	20 ppmv H_2S	Mass Balance	2.02 tpy
			Diesel		13.1 gal/hr	15 ppmw S	Mass Balance	1.2E-02 tpy
2	Generator Engine	17.1 MW	NG	8,760 hr/yr	129,548 scf/hr	20 ppmv H_2S	Mass Balance	2.02 tpy
			Diesel		13.1 gal/hr	15 ppmw S	Mass Balance	1.2E-02 tpy
3	Generator Engine	17.1 MW	NG	8,760 hr/yr	129,548 scf/hr	20 ppmv H_2S	Mass Balance	2.02 tpy
			Diesel		13.1 gal/hr	15 ppmw S	Mass Balance	1.2E-02 tpy
4	Generator Engine	17.1 MW	NG	8,760 hr/yr	129,548 scf/hr	20 ppmv H_2S	Mass Balance	2.02 tpy
			Diesel		13.1 gal/hr	15 ppmw S	Mass Balance	1.2E-02 tpy
5	Generator Engine	17.1 MW	NG	8,760 hr/yr	129,548 scf/hr	20 ppmv H_2S	Mass Balance	2.02 tpy
			Diesel		13.1 gal/hr	15 ppmw S	Mass Balance	1.2E-02 tpy
6	Generator Engine	17.1 MW	NG	8,760 hr/yr	129,548 scf/hr	20 ppmv H_2S	Mass Balance	2.02 tpy
			Diesel		13.1 gal/hr	15 ppmw S	Mass Balance	1.2E-02 tpy
7	Generator Engine	17.1 MW	NG	8,760 hr/yr	129,548 scf/hr	20 ppmv H_2S	Mass Balance	2.02 tpy
			Diesel		13.1 gal/hr	15 ppmw S	Mass Balance	1.2E-02 tpy
8	Generator Engine	17.1 MW	NG	8,760 hr/yr	129,548 scf/hr	20 ppmv H_2S	Mass Balance	2.02 tpy
			Diesel		13.1 gal/hr	15 ppmw S	Mass Balance	1.2E-02 tpy
9	Generator Engine	17.1 MW	NG	8,760 hr/yr	129,548 scf/hr	20 ppmv H_2S	Mass Balance	2.02 tpy
			Diesel		13.1 gal/hr	15 ppmw S	Mass Balance	1.2E-02 tpy
10	Generator Engine	17.1 MW	NG	8,760 hr/yr	129,548 scf/hr	20 ppmv H_2S	Mass Balance	2.02 tpy
			Diesel		13.1 gal/hr	15 ppmw S	Mass Balance	1.2E-02 tpy
1-10 (combined)	Generator Engines	17.1 MW (each)	ULSD Exclusively	0 hr/yr (combined)	1,114.6 gal/hr (each)	15 ppmw S	Mass Balance	0 tpy
11	Firewater Pump Engine	197 hp	ULSD	500 hr/yr	10.3 gal/hr	15 ppmw S	Mass Balance	5.3E-04 tpy
12	Black Start Generator Engine	1,490 hp	ULSD	1,000 hr/yr (combined)	71.9 gal/hr	15 ppmw S	Mass Balance	7.4E-03 tpy
18	Black Start Generator Engine	1,490 hp	ULSD		71.9 gal/hr	15 ppmw S	Mass Balance	
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	8,760 hr/yr	15,752 scf/hr	20 ppmv H_2S	Mass Balance	0.25 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	8,760 hr/yr	15,752 scf/hr	20 ppmv H_2S	Mass Balance	0.25 tpy
13-14 (combined)	Auxiliary Boilers	15.75 MMBtu/hr (each)	ULSD	0 hr/yr (combined)	110.3 gal/hr (each)	15 ppmw S	Mass Balance	0 tpy
17	Natural Gas Fuel Heater	8.3 MMBtu/hr	NG	8,760 hr/yr	8,137 scf/hr	20 ppmv H_2S	Mass Balance	0.13 tpy
							Subtotal:	**20.98 tpy**
Insignificant Emission Units								
15	Diesel Storage Tank	509,000 gal	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
16	Diesel Storage Tank	509,000 gal	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Lube Oil Storage Tank	18,784 gal	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Used Lube Oil Storage Tank	14,898 gal	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Service Lube Oil Storage Tank (2)	19,474 gal (each)	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Wastewater/Lube Oil Storage Tank	14,898 gal	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Diesel Storage Tank (2)	1,000 gal (each)	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Diesel Storage Tank	300 gal	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Diesel Storage Tank (2)	660 gal (each)	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Diesel Engine Lube Oil Reservoirs (10)	3,500 gal (each)	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
							Subtotal:	**0.00 tpy**
							Total SO_2 Emissions:	**20.98 tpy**

Notes:

1. H_2S concentration and S content limited per Condition 15 of Permit No. AQ1086MSS03.

2. Emissions calculations are based on worst case scenario for dual fuel-fired units, EU IDs 1-10, 13, and 14.

Table A-7. Volatile Organic Compound (VOC) Emissions
Matanuska Electric Association - Eklutna Generation Station

ID	Emission Unit Name	Rating / Capacity	Fuel Type	Proposed Operations for Maximum VOC Emissions	VOC Emission Factor	Reference	Proposed VOC Emissions
Significant Emission Units							
1	Generator Engine	17.1 MW	NG / ULSD	7,916 hr/yr	3.43 lb/hr	Manufacturer Data	13.59 tpy
2	Generator Engine	17.1 MW	NG / ULSD	7,916 hr/yr	3.43 lb/hr	Manufacturer Data	13.59 tpy
3	Generator Engine	17.1 MW	NG / ULSD	7,916 hr/yr	3.43 lb/hr	Manufacturer Data	13.59 tpy
4	Generator Engine	17.1 MW	NG / ULSD	7,916 hr/yr	3.43 lb/hr	Manufacturer Data	13.59 tpy
5	Generator Engine	17.1 MW	NG / ULSD	7,916 hr/yr	3.43 lb/hr	Manufacturer Data	13.59 tpy
6	Generator Engine	17.1 MW	NG / ULSD	7,916 hr/yr	3.43 lb/hr	Manufacturer Data	13.59 tpy
7	Generator Engine	17.1 MW	NG / ULSD	7,916 hr/yr	3.43 lb/hr	Manufacturer Data	13.59 tpy
8	Generator Engine	17.1 MW	NG / ULSD	7,916 hr/yr	3.43 lb/hr	Manufacturer Data	13.59 tpy
9	Generator Engine	17.1 MW	NG / ULSD	7,916 hr/yr	3.43 lb/hr	Manufacturer Data	13.59 tpy
10	Generator Engine	17.1 MW	NG / ULSD	7,916 hr/yr	3.43 lb/hr	Manufacturer Data	13.59 tpy
1-10 (combined)	Generator Engines	17.1 MW (each)	ULSD Exclusively	8,440 hr/yr (combined)	7.91 lb/hr	Manufacturer Data	33.36 tpy
11	Firewater Pump Engine	197 hp	ULSD	500 hr/yr	0.1 g/hp-hr	Manufacturer Data	1.1E-02 tpy
12	Black Start Generator Engine	1,490 hp	ULSD	1,000 hr/yr (combined)	0.12 g/hp-hr	Manufacturer Data	0.20 tpy
18	Black Start Generator Engine	1,490 hp	ULSD		0.12 g/hp-hr	Manufacturer Data	
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	8,760 hr/yr	0.063 lb/hr	Manufacturer Data	0.28 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	8,760 hr/yr	0.063 lb/hr	Manufacturer Data	0.28 tpy
13-14 (combined)	Auxiliary Boilers	15.75 MMBtu/hr (each)	ULSD	0 hr/yr (combined)	0.062 lb/hr	Manufacturer Data	0 tpy
17	Natural Gas Fuel Heater	8.3 MMBtu/hr	NG	8,760 hr/yr	0.025 lb/MMBtu	Manufacturer Data	0.91 tpy
						Subtotal:	**170.88 tpy**
Insignificant Emission Units							
15	Diesel Storage Tank	509,000 gal	N/A	8,760 hr/yr	0.13 tpy	See Table A-8	0.13 tpy
16	Diesel Storage Tank	509,000 gal	N/A	8,760 hr/yr	0.13 tpy	See Table A-8	0.13 tpy
N/A	Lube Oil Storage Tank	18,784 gal	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Used Lube Oil Storage Tank	14,898 gal	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Service Lube Oil Storage Tank (2)	19,474 gal (each)	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Wastewater/Lube Oil Storage Tank	14,898 gal	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Diesel Storage Tank (2)	1,000 gal (each)	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Diesel Storage Tank	300 gal	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Diesel Storage Tank (2)	660 gal (each)	N/A	8,760 hr/yr	N/A	N/A	0 tpy
N/A	Diesel Engine Lube Oil Reservoirs (10)	3,500 gal (each)	N/A	8,760 hr/yr	N/A	N/A	0 tpy
						Subtotal:	**0.27 tpy**
						Total VOC Emissions:	**171.15 tpy**

Notes:

1. Emissions calculations are based on worst case scenario for dual fuel-fired units; see Table A-12 for EU IDs 1-10.

2. EU IDs 1-10 undergo annual source testing for NO_X, CO, and VOC when burning NG per 40 CFR 60 Subpart JJJJ (two units per year per custom monitoring waiver); manufacturer data is used as worst-case.

Table A-8. Volatile Organic Compound (VOC) Emission Factors - Diesel Tanks (AP-42, Section 7.1)
Matanuska Electric Association - Eklutna Generation Station

Tank Name	EU ID 15	EU ID 16
Orientation	Vertical Fixed Roof	Vertical Fixed Roof
Contents	Diesel	Diesel
Capacity (gallons)	509,000	509,000
Diameter, D (ft)	52.0	52.0
Radius, R_S (ft)	26.0	26.0
Shell Height, H_S (ft)	32.0	32.0
Average Liquid Height (H_L)	16.0	16.0
Maximum Liquid Height (H_{LX})	31.0	31.0
Diesel Throughput (gal/yr)	11,824,701	11,824,701
Color	White	White
Paint Condition	Good	Good
Roof Type	Cone	Cone
Slope, S_R (ft/ft)	0.0625	0.0625
Standing Loss (L_S) Calculations		
Vapor Space Expansion Factor, K_E	0.022	0.022
Vapor Space Outage, H_{VO} (ft)	16.54	16.54
Average Daily Ambient Temperature, T_{AA} (°R)	495.57	495.57
Liquid Bulk Temperature, T_B (°R)	496.00	496.00
Average Daily Liquid Surface Temperature, T_{LA} (°R)	496.54	496.54
Vented Vapor Saturation Factor, K_S	0.9948	0.9948
Vapor Density, W_V (lb/ft^3)	1.46E-04	1.46E-04
Standing Loss, L_S (lb/yr)	41.57	41.57
Working Loss (L_W) Calculations		
Tank Maximum Liquid Volume, V_{LX} (ft^3)	65,835	65,835
Number of Turnovers per Year, N	24.01	24.01
Turnover Factor, K_N	1.0	1.0
Working Loss, L_W (lb/yr)	226.69	226.69
Total VOCs (tpy)	**0.13**	**0.13**

Inputs (Anchorage, AK):

T_{AX} =	42.7 °F	502.4 °R
T_{AN} =	29.1 °F	488.8 °R
a =	0.17 New, White	
I =	838 Btu/ft^2-d	

Constants:

M_V (diesel)=	130 lb/lb-mol
P_{VA} (diesel)=	0.006 psi
K_P =	1

Table A-9. Carbon Dioxide Equivalent (CO_2e) Emissions

Matanuska Electric Association - Eklutna Generation Station

ID	Emission Unit Name	Rating / Capacity	Fuel Type	Proposed Operations for Maximum CO_2e Emissions	Maximum Heat Rate	CO_2e Emission Factor	Reference	Proposed CO_2e Emissions
Significant Emission Units								
1	Generator Engine	17.1 MW	NG	7,916 hr/yr	132.14 MMBtu/hr	53.1145 kg/MMBtu	40 CFR 98, Tbl C-1, 2	61,242 tpy
			Diesel		1.81 MMBtu/hr	75.4030 kg/MMBtu	40 CFR 98, Tbl C-1, 2	1,191 tpy
2	Generator Engine	17.1 MW	NG	7,916 hr/yr	132.14 MMBtu/hr	53.1145 kg/MMBtu	40 CFR 98, Tbl C-1, 2	61,242 tpy
			Diesel		1.81 MMBtu/hr	75.4030 kg/MMBtu	40 CFR 98, Tbl C-1, 2	1,191 tpy
3	Generator Engine	17.1 MW	NG	7,916 hr/yr	132.14 MMBtu/hr	53.1145 kg/MMBtu	40 CFR 98, Tbl C-1, 2	61,242 tpy
			Diesel		1.81 MMBtu/hr	75.4030 kg/MMBtu	40 CFR 98, Tbl C-1, 2	1,191 tpy
4	Generator Engine	17.1 MW	NG	7,916 hr/yr	132.14 MMBtu/hr	53.1145 kg/MMBtu	40 CFR 98, Tbl C-1, 2	61,242 tpy
			Diesel		1.81 MMBtu/hr	75.4030 kg/MMBtu	40 CFR 98, Tbl C-1, 2	1,191 tpy
5	Generator Engine	17.1 MW	NG	7,916 hr/yr	132.14 MMBtu/hr	53.1145 kg/MMBtu	40 CFR 98, Tbl C-1, 2	61,242 tpy
			Diesel		1.81 MMBtu/hr	75.4030 kg/MMBtu	40 CFR 98, Tbl C-1, 2	1,191 tpy
6	Generator Engine	17.1 MW	NG	7,916 hr/yr	132.14 MMBtu/hr	53.1145 kg/MMBtu	40 CFR 98, Tbl C-1, 2	61,242 tpy
			Diesel		1.81 MMBtu/hr	75.4030 kg/MMBtu	40 CFR 98, Tbl C-1, 2	1,191 tpy
7	Generator Engine	17.1 MW	NG	7,916 hr/yr	132.14 MMBtu/hr	53.1145 kg/MMBtu	40 CFR 98, Tbl C-1, 2	61,242 tpy
			Diesel		1.81 MMBtu/hr	75.4030 kg/MMBtu	40 CFR 98, Tbl C-1, 2	1,191 tpy
8	Generator Engine	17.1 MW	NG	7,916 hr/yr	132.14 MMBtu/hr	53.1145 kg/MMBtu	40 CFR 98, Tbl C-1, 2	61,242 tpy
			Diesel		1.81 MMBtu/hr	75.4030 kg/MMBtu	40 CFR 98, Tbl C-1, 2	1,191 tpy
9	Generator Engine	17.1 MW	NG	7,916 hr/yr	132.14 MMBtu/hr	53.1145 kg/MMBtu	40 CFR 98, Tbl C-1, 2	61,242 tpy
			Diesel		1.81 MMBtu/hr	75.4030 kg/MMBtu	40 CFR 98, Tbl C-1, 2	1,191 tpy
10	Generator Engine	17.1 MW	NG	7,916 hr/yr	132.14 MMBtu/hr	53.1145 kg/MMBtu	40 CFR 98, Tbl C-1, 2	61,242 tpy
			Diesel		1.81 MMBtu/hr	75.4030 kg/MMBtu	40 CFR 98, Tbl C-1, 2	1,191 tpy
1-10 (combined)	Generator Engines	17.1 MW (each)	ULSD Exclusively	8,440 hr/yr (combined)	153.81 MMBtu/hr (each)	75.4030 kg/MMBtu	40 CFR 98, Tbl C-1, 2	107,901 tpy
11	Firewater Pump Engine	197 hp	ULSD	500 hr/yr	1.42 MMBtu/hr	75.4030 kg/MMBtu	40 CFR 98, Tbl C-1, 2	59 tpy
12	Black Start Generator Engine	1,490 hp	ULSD	1,000 hr/yr (combined)	9.92 MMBtu/hr	75.4030 kg/MMBtu	40 CFR 98, Tbl C-1, 2	825 tpy
18	Black Start Generator Engine	1,490 hp	ULSD		9.92 MMBtu/hr	75.4030 kg/MMBtu	40 CFR 98, Tbl C-1, 2	
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	8,260 hr/yr	15.75 MMBtu/hr	53.1145 kg/MMBtu	40 CFR 98, Tbl C-1, 2	7,617 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	8,260 hr/yr	15.75 MMBtu/hr	53.1145 kg/MMBtu	40 CFR 98, Tbl C-1, 2	7,617 tpy
13-14 (combined)	Auxiliary Boilers	15.75 MMBtu/hr (each)	ULSD	1,000 hr/yr (combined)	15.75 MMBtu/hr	75.4030 kg/MMBtu	40 CFR 98, Tbl C-1, 2	1,309 tpy
17	Natural Gas Fuel Heater	8.3 MMBtu/hr	NG	8,760 hr/yr	8.3 MMBtu/hr	53.1145 kg/MMBtu	40 CFR 98, Tbl C-1, 2	4,257 tpy
						Subtotal:		**753,909 tpy**
Insignificant Emission Units								
15	Diesel Storage Tank	509,000 gal	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
16	Diesel Storage Tank	509,000 gal	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Lube Oil Storage Tank	18,784 gal	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Used Lube Oil Storage Tank	14,898 gal	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Service Lube Oil Storage Tank (2)	19,474 gal (each)	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Wastewater/Lube Oil Storage Tank	14,898 gal	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Diesel Storage Tank (2)	1,000 gal (each)	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Diesel Storage Tank	300 gal	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Diesel Storage Tank (2)	660 gal (each)	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Diesel Engine Lube Oil Reservoirs (10)	3,500 gal (each)	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
							Subtotal:	**0 tpy**
							Total CO_2e Emissions:	**753,909 tpy**

Notes:

1. Emissions calculations are based on worst case scenario for dual fuel-fired units, EU IDs 1-10, 13 and 14.
2. Updated the global warming potential values based Table A-1 to Subpart A of 40 CFR 98.

Table A-10. Hazardous Air Pollutant (HAP) Emissions
Matanuska Electric Association - Eklutna Generation Station

ID	Emission Unit Name	Rating / Capacity	Fuel Type	Proposed Operations for Maximum HAP Emissions	Maximum Heat Rate	HAP Emission Factor	Reference	Proposed HAP Emissions
Significant Emission Units								
1	Emission Unit Name	17.1 MW	NG	8,760 hr/yr	132.14 MMBtu/hr	2.75E-03 lb/MMBtu	See Table A-11	1.59 tpy
			Diesel		1.54 MMBtu/hr	9.94E-04 lb/MMBtu	See Table A-11	6.7E-03 tpy
2	Generator Engine	17.1 MW	NG	8,760 hr/yr	132.14 MMBtu/hr	2.75E-03 lb/MMBtu	See Table A-11	1.59 tpy
			Diesel		1.49 MMBtu/hr	9.94E-04 lb/MMBtu	See Table A-11	6.5E-03 tpy
3	Generator Engine	17.1 MW	NG	8,760 hr/yr	132.14 MMBtu/hr	2.75E-03 lb/MMBtu	See Table A-11	1.59 tpy
			Diesel		1.49 MMBtu/hr	9.94E-04 lb/MMBtu	See Table A-11	6.5E-03 tpy
4	Generator Engine	17.1 MW	NG	8,760 hr/yr	132.14 MMBtu/hr	2.75E-03 lb/MMBtu	See Table A-11	1.59 tpy
			Diesel		1.49 MMBtu/hr	9.94E-04 lb/MMBtu	See Table A-11	6.5E-03 tpy
5	Generator Engine	17.1 MW	NG	8,760 hr/yr	132.14 MMBtu/hr	2.75E-03 lb/MMBtu	See Table A-11	1.59 tpy
			Diesel		1.49 MMBtu/hr	9.94E-04 lb/MMBtu	See Table A-11	6.5E-03 tpy
6	Generator Engine	17.1 MW	NG	8,760 hr/yr	132.14 MMBtu/hr	2.75E-03 lb/MMBtu	See Table A-11	1.59 tpy
			Diesel		1.49 MMBtu/hr	9.94E-04 lb/MMBtu	See Table A-11	6.5E-03 tpy
7	Generator Engine	17.1 MW	NG	8,760 hr/yr	132.14 MMBtu/hr	2.75E-03 lb/MMBtu	See Table A-11	1.59 tpy
			Diesel		1.49 MMBtu/hr	9.94E-04 lb/MMBtu	See Table A-11	6.5E-03 tpy
8	Generator Engine	17.1 MW	NG	8,760 hr/yr	132.14 MMBtu/hr	2.75E-03 lb/MMBtu	See Table A-11	1.59 tpy
			Diesel		1.49 MMBtu/hr	9.94E-04 lb/MMBtu	See Table A-11	6.5E-03 tpy
9	Generator Engine	17.1 MW	NG	8,760 hr/yr	132.14 MMBtu/hr	2.75E-03 lb/MMBtu	See Table A-11	1.59 tpy
			Diesel		1.49 MMBtu/hr	9.94E-04 lb/MMBtu	See Table A-11	6.5E-03 tpy
10	Generator Engine	17.1 MW	NG	8,760 hr/yr	132.14 MMBtu/hr	2.75E-03 lb/MMBtu	See Table A-11	1.59 tpy
			Diesel		1.49 MMBtu/hr	9.94E-04 lb/MMBtu	See Table A-11	6.5E-03 tpy
1-10 (combined)	Generator Engines	17.1 MW (each)	ULSD Exclusively	0 hr/yr (combined)	153.93 MMBtu/hr (each)	9.94E-04 lb/MMBtu	See Table A-11	0 tpy
11	Firewater Pump Engine	197 hp	ULSD	500 hr/yr	1.42 MMBtu/hr	3.87E-03 lb/MMBtu	See Table A-11	1.4E-03 tpy
12	Black Start Generator Engine	1,490 hp	ULSD	1,000 hr/yr (combined)	9.92 MMBtu/hr	1.57E-03 lb/MMBtu	See Table A-11	7.8E-03 tpy
18	Black Start Generator Engine	1,490 hp	ULSD		9.92 MMBtu/hr	1.57E-03 lb/MMBtu	See Table A-11	
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	8,760 hr/yr	15,752 scf/hr	1.89 lb/MMscf	See Table A-11	0.13 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	8,760 hr/yr	15,752 scf/hr	1.89 lb/MMscf	See Table A-11	0.13 tpy
13-14 (combined)	Auxiliary Boilers	15.75 MMBtu/hr (each)	ULSD	0 hr/yr (combined)	110.31 gal/hr (each)	0.050 lb/10^3 gal	See Table A-11	0 tpy
17	Natural Gas Fuel Heater	8.3 MMBtu/hr	NG	8,760 hr/yr	8.3 MMBtu/hr	1.89 lb/MMscf	See Table A-11	6.7E-02 tpy
							Subtotal:	**16.29 tpy**
Insignificant Emission Units								
15	Diesel Storage Tank	509,000 gal	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
16	Diesel Storage Tank	509,000 gal	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Lube Oil Storage Tank	18,784 gal	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Used Lube Oil Storage Tank	14,898 gal	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Service Lube Oil Storage Tank (2)	19,474 gal (each)	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Wastewater/Lube Oil Storage Tank	14,898 gal	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Diesel Storage Tank (2)	1,000 gal (each)	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Diesel Storage Tank	300 gal	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Diesel Storage Tank (2)	660 gal (each)	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
N/A	Diesel Engine Lube Oil Reservoirs (10)	3,500 gal (each)	N/A	8,760 hr/yr	N/A	N/A	N/A	0 tpy
							Subtotal:	**0.00 tpy**
							Total HAP Emissions:	**16.29 tpy**
							Highest Individual HAP (Formaldehyde):	**4.40 tpy**

Notes:

1. Emissions calculations are based on worst case scenario for dual fuel-fired units, EU IDs 1-10, 13, and 14.

Table A-11. Hazardous Air Pollutant (HAP) Emission Factors
Matanuska Electric Association - Eklutna Generation Station

Pollutant	EU IDs 1-10 (NG) AP-42 Table 3.2-2	EU IDs 1-10 (ULSD) AP-42 Table 3.4-3, 4	EU IDs 12 & 18 AP-42 Table 3.4-3, 4	EU ID 11 AP-42 Table 3.3-2	EU ID 13 & 14 (ULSD) AP-42 Table 1.3-8, 9, 11	EU IDs 13, 14, 17 (NG) AP-42 Table 1.4-2, 3
1,3-Butadiene	3.71E-04 lb/MMBtu[2]			3.91E-05 lb/MMBtu		
1,3-Dicholorbenzene						1.2E-03 lb/MMscf
1,1-Dichloroethane	2.36E-05 lb/MMBtu					
1,2-Dichloroethane	2.36E-05 lb/MMBtu					
1,2-Dichloropropane	2.69E-05 lb/MMBtu					
1,3-Dichloropropene	2.64E-05 lb/MMBtu					
7,12-Dimethylbenz(a)anthracene						1.6E-05 lb/MMscf
2-Methylnaphthalene	3.32E-05 lb/MMBtu					2.4E-05 lb/MMscf
3-Methylcholanthrene						1.8E-06 lb/MMscf
1,1,2,2-Tetrachloroethane	4.00E-05 lb/MMBtu					
1,1,1-Trichloroethane					2.36E-04 lb/10^3 gal	
1,1,2-Trichloroethane	3.18E-05 lb/MMBtu					
2,2,4-Trimethylpentane	2.50E-04 lb/MMBtu					
Acenaphthene	1.53E-07 lb/MMBtu[2]	4.68E-06 lb/MMBtu	4.68E-06 lb/MMBtu	1.42E-06 lb/MMBtu	2.11E-05 lb/10^3 gal	1.8E-06 lb/MMscf
Acenaphthylene	5.06E-07 lb/MMBtu[2]	9.23E-06 lb/MMBtu	9.23E-06 lb/MMBtu	5.06E-06 lb/MMBtu	2.53E-07 lb/10^3 gal	1.8E-06 lb/MMscf
Acetaldehyde	5.19E-04 lb/MMBtu[2]	2.52E-05 lb/MMBtu	2.52E-05 lb/MMBtu	7.67E-04 lb/MMBtu		
Acrolein	3.84E-05 lb/MMBtu[2]	7.88E-06 lb/MMBtu	7.88E-06 lb/MMBtu	9.25E-05 lb/MMBtu		
Anthracene		1.23E-06 lb/MMBtu	1.23E-06 lb/MMBtu	1.87E-06 lb/MMBtu	1.22E-06 lb/10^3 gal	2.4E-06 lb/MMscf
Arsenic					5.52E-04 lb/10^3 gal	2.0E-04 lb/MMscf
Benz(a)anthracene		6.22E-07 lb/MMBtu	6.22E-07 lb/MMBtu	1.68E-06 lb/MMBtu	4.01E-06 lb/10^3 gal	1.8E-06 lb/MMscf
Benzene	2.08E-04 lb/MMBtu[2]	7.76E-04 lb/MMBtu	7.76E-04 lb/MMBtu	9.33E-04 lb/MMBtu	2.14E-04 lb/10^3 gal	2.1E-03 lb/MMscf
Benzo(a)pyrene	4.15E-07 lb/MMBtu	2.57E-07 lb/MMBtu	2.57E-07 lb/MMBtu	1.88E-07 lb/MMBtu		1.2E-06 lb/MMscf
Benzo(b)fluoranthene	1.66E-07 lb/MMBtu	1.11E-06 lb/MMBtu	1.11E-06 lb/MMBtu	9.91E-08 lb/MMBtu	1.48E-06 lb/10^3 gal	1.8E-06 lb/MMscf
Benzo(g,h,l)perylene	4.14E-07 lb/MMBtu	5.56E-07 lb/MMBtu	5.56E-07 lb/MMBtu	4.89E-07 lb/MMBtu	2.26E-06 lb/10^3 gal	1.2E-06 lb/MMscf
Benzo(k)fluoranthene	8.37E-09 lb/MMBtu[2]	2.18E-07 lb/MMBtu	2.18E-07 lb/MMBtu	1.55E-07 lb/MMBtu		1.8E-06 lb/MMscf
Beryllium					4.14E-04 lb/10^3 gal	1.2E-05 lb/MMscf
Biphenyl	2.12E-04 lb/MMBtu					
Cadmium					4.14E-04 lb/10^3 gal	1.1E-03 lb/MMscf
Carbon Tetrachloride	3.67E-05 lb/MMBtu					
Chlorobenzene	3.04E-05 lb/MMBtu					
Chloroform	2.85E-05 lb/MMBtu					
Chromium					4.14E-04 lb/10^3 gal	1.4E-03 lb/MMscf
Chrysene	1.55E-08 lb/MMBtu[2]	1.53E-06 lb/MMBtu	1.53E-06 lb/MMBtu	3.53E-07 lb/MMBtu	2.38E-06 lb/10^3 gal	1.8E-06 lb/MMscf
Cobalt						8.4E-05 lb/MMscf
Dibenzo(a,h)anthracene	2.47E-09 lb/MMBtu[2]	3.46E-07 lb/MMBtu	3.46E-07 lb/MMBtu	5.83E-07 lb/MMBtu	1.67E-06 lb/10^3 gal	1.2E-06 lb/MMscf
Ethylbenzene	3.97E-05 lb/MMBtu				6.36E-05 lb/10^3 gal	
Ethylene Dibromide	4.43E-05 lb/MMBtu					
Fluoranthene	2.93E-07 lb/MMBtu[2]	4.03E-06 lb/MMBtu	4.03E-06 lb/MMBtu	7.61E-06 lb/MMBtu	4.48E-06 lb/10^3 gal	3.0E-06 lb/MMscf
Fluorene	3.42E-07 lb/MMBtu[2]	1.28E-05 lb/MMBtu	1.28E-05 lb/MMBtu	2.92E-05 lb/MMBtu	4.47E-06 lb/10^3 gal	2.8E-06 lb/MMscf
Formaldehyde	7.57E-04 lb/MMBtu[3]	1.82E-03 lb/MMBtu[4]	7.89E-05 lb/MMBtu	1.18E-03 lb/MMBtu	3.50E-02 lb/10^3 gal	7.5E-02 lb/MMscf
Indeno(1,2,3-cd)pyrene	7.90E-09 lb/MMBtu[2]	4.14E-07 lb/MMBtu	4.14E-07 lb/MMBtu	3.75E-07 lb/MMBtu	2.14E-06 lb/10^3 gal	1.8E-06 lb/MMscf
Lead					1.24E-03 lb/10^3 gal	5.0E-04 lb/MMscf
Manganese					8.28E-04 lb/10^3 gal	3.8E-04 lb/MMscf
Mercury					4.14E-04 lb/10^3 gal	2.6E-04 lb/MMscf
Methanol	2.50E-03 lb/MMBtu					
Methylene Chloride	2.00E-05 lb/MMBtu					

Table A-11. Hazardous Air Pollutant (HAP) Emission Factors
Matanuska Electric Association - Eklutna Generation Station

Pollutant	EU IDs 1-10 (NG) AP-42 Table 3.2-2	EU IDs 1-10 (ULSD) AP-42 Table 3.4-3, 4	EU IDs 12 & 18 AP-42 Table 3.4-3, 4	EU ID 11 AP-42 Table 3.3-2	EU ID 13 & 14 (ULSD) AP-42 Table 1.3-8, 9, 11	EU IDs 13, 14, 17 (NG) AP-42 Table 1.4-2, 3
Naphthalene	2.29E-05 lb/MMBtu[2]	1.30E-04 lb/MMBtu	1.30E-04 lb/MMBtu	8.48E-05 lb/MMBtu	1.13E-03 lb/10^3 gal	6.1E-04 lb/MMscf
n-Hexane	1.11E-03 lb/MMBtu					1.8E+00 lb/MMscf
Nickel					4.14E-04 lb/10^3 gal	2.1E-03 lb/MMscf
Perchloroethylene	2.48E-06 lb/MMBtu					
Phenanthrene	1.76E-06 lb/MMBtu[2]	4.08E-05 lb/MMBtu	4.08E-05 lb/MMBtu	2.94E-05 lb/MMBtu	1.05E-05 lb/10^3 gal	1.7E-05 lb/MMscf
Phenol	2.40E-05 lb/MMBtu					
Pyrene	1.87E-07 lb/MMBtu[2]	3.71E-06 lb/MMBtu	3.71E-06 lb/MMBtu	4.78E-06 lb/MMBtu	4.25E-06 lb/10^3 gal	5.0E-06 lb/MMscf
Selenium					2.07E-03 lb/10^3 gal	2.4E-05 lb/MMscf
Styrene	2.36E-05 lb/MMBtu					
Toluene	2.54E-04 lb/MMBtu[2]	2.81E-04 lb/MMBtu	2.81E-04 lb/MMBtu	4.09E-04 lb/MMBtu	6.20E-03 lb/10^3 gal	3.4E-03 lb/MMscf
Vinyl Chloride	1.49E-05 lb/MMBtu					
Xylenes	6.72E-04 lb/MMBtu[2]	1.93E-04 lb/MMBtu	1.93E-04 lb/MMBtu	2.85E-04 lb/MMBtu	1.09E-04 lb/10^3 gal	
Total HAPs	**7.39E-03 lb/MMBtu**	**3.31E-03 lb/MMBtu**	**1.57E-03 lb/MMBtu**	**3.87E-03 lb/MMBtu**	**4.98E-02 lb/10^3 gal**	**1.89 lb/MMscf**
Total HAPs (Controlled[5])	**2.75E-03 lb/MMBtu**	**9.94E-04 lb/MMBtu**	**N/A**	**N/A**	**N/A**	**N/A**

Notes:

1. Emission factors are from AP-42 unless otherwise noted.

2. Emission factors are from median values from the California Air Toxics Emission Factors (CATEF) database (4S/Lean/>650Hp).

3. Emission factor based on source test results for formaldehyde for EU IDs 1-10 (NG) submitted to ADEC on April 2, 2015 (0.1 lb/hr).

4. Emission factor for formaldehyde for EU IDs 1-10 (diesel) based on manufacturer data.

5. HAP emission control efficiency estimated at 70 percent for catalytic oxidation on EU IDs 1-10 (all pollutants except formaldehyde which was source tested).

Table A-12a. Worst-Case Emissions for EU IDs 1-10 (as Limited by NO_X Cap)
Matanuska Electric Association - Eklutna Generation Station

Fuel	NO_X Emission Factor	CO Emission Factor	VOC Emission Factor	Proposed Operations for Maximum Emissions [1,2]	NO_X Emissions (tpy)	CO Emissions (tpy)	VOC Emissions(tpy)
NG / ULSD	3.43 lb/hr	4.52 lb/hr	3.43 lb/hr	7,916 hr/yr	135.76 tpy	178.81 tpy	135.85 tpy
Diesel	19.95 lb/hr	6.78 lb/hr	7.91 lb/hr	844 hr/yr	84.19 tpy	28.60 tpy	33.36 tpy
				8,760 hr/yr	**219.95** tpy	**207.40** tpy	**169.21** tpy

Fuel	NO_X Emission Factor	CO Emission Factor	VOC Emission Factor	Proposed Operations for Maximum Emissions [1,2]	NO_X Emissions (tpy)	CO Emissions (tpy)	VOC Emissions(tpy)
NG / ULSD	3.43 lb/hr	4.52 lb/hr	3.43 lb/hr	8,760 hr/yr	150.23 tpy	197.87 tpy	150.34 tpy
Diesel	19.95 lb/hr	6.78 lb/hr	7.91 lb/hr	0 hr/yr	0.00 tpy	0.00 tpy	0.00 tpy
				8,760 hr/yr	150.23 tpy	197.87 tpy	150.34 tpy

Fuel	NO_X Emission Factor	CO Emission Factor	VOC Emission Factor	Proposed Operations for Maximum Emissions [1,2]	NO_X Emissions (tpy)	CO Emissions (tpy)	VOC Emissions(tpy)
NG / ULSD	3.43 lb/hr	4.52 lb/hr	3.43 lb/hr	0 hr/yr	0.00 tpy	0.00 tpy	0.00 tpy
Diesel	19.95 lb/hr	6.78 lb/hr	7.91 lb/hr	2,205 hr/yr	219.95 tpy	74.71 tpy	87.16 tpy
				2,205 hr/yr	**219.95** tpy	74.71 tpy	87.16 tpy

Table A-12b. Worst-Case Emissions for EU IDs 1-10 (as Limited by PM_{10} Cap)
Matanuska Electric Association - Eklutna Generation Station

Fuel	PM Emission Factor	CO Emission Factor	VOC Emission Factor	Proposed Operations for Maximum Emissions [1,2]	PM Emissions (tpy)	CO Emissions (tpy)	VOC Emissions(tpy)
NG / ULSD	4.89 lb/hr	4.52 lb/hr	3.43 lb/hr	8,568 hr/yr	209.49 tpy	193.53 tpy	147.04 tpy
Diesel	10.92 lb/hr	6.78 lb/hr	7.91 lb/hr	192 hr/yr	10.48 tpy	6.51 tpy	7.59 tpy
				8,760 hr/yr	**219.97** tpy	200.04 tpy	154.63 tpy

Fuel	PM Emission Factor	CO Emission Factor	VOC Emission Factor	Proposed Operations for Maximum Emissions [1,2]	PM Emissions (tpy)	CO Emissions (tpy)	VOC Emissions(tpy)
NG / ULSD	4.89 lb/hr	4.52 lb/hr	3.43 lb/hr	8,760 hr/yr	214.18 tpy	197.87 tpy	150.34 tpy
Diesel	10.92 lb/hr	6.78 lb/hr	7.91 lb/hr	0 hr/yr	0.00 tpy	0.00 tpy	0.00 tpy
				8,760 hr/yr	214.18 tpy	197.87 tpy	150.34 tpy

Fuel	PM Emission Factor	CO Emission Factor	VOC Emission Factor	Proposed Operations for Maximum Emissions [3]	PM Emissions (tpy)	CO Emissions (tpy)	VOC Emissions(tpy)
NG / ULSD	4.89 lb/hr	4.52 lb/hr	3.43 lb/hr	0 hr/yr	0.00 tpy	0.00 tpy	0.00 tpy
Diesel	10.92 lb/hr	6.78 lb/hr	7.91 lb/hr	2,205 hr/yr	120.36 tpy	74.71 tpy	87.16 tpy
				2,205 hr/yr	120.36 tpy	74.71 tpy	87.16 tpy

Notes:

1. Requesting that the hour limit on diesel fuel in Condition 5 of Permit No. AQ1086MSS03 be changed to NO_X and PM_{10} emission limits for EU IDs 1-10.
2. Emissions calculations are based on worst case scenario for dual fuel-fired units, EU IDs 1-10, as projected in the table above and as limited by either NO_X or PM_{10}.
3. The maximum hours of operation are limited by the NO_X emission limit.

Attachment B

Revise or Rescind Title I Permit Conditions

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ATTACHMENT B: REVISE OR RESCIND TITLE I PERMIT CONDITIONS

Matanuska Electric Association, Inc. (MEA) requests revisions to Title I Minor Permit No. AQ1086MSS03 for Eklutna Generation Station under 18 AAC 50.508(6). The proposed revisions will provide flexibility for MEA to operate the dual fuel-fired generator engines in diesel-fired mode at greater frequencies than currently authorized. This permit revision is necessary because MEA has been informed by its suppliers that delivery of natural gas will not be guaranteed on any upcoming contracts due to expected natural gas supply shortages.

Per 18 AAC 50.540(k), an application for a minor permit to revise or rescind terms and conditions of a Title I permit under 18 AAC 50.508(6) must include the information required by 18 AAC 50.540(k)(1) through (4). Each required element is addressed below.

18 AAC 50.540(k)(1)

Per 18 AAC 50.540(k)(1), a copy of Minor Permit No. AQ1086MSS03 is included in Attachment D.

18 AAC 50.540(k)(2)

Per 18 AAC 50.540(k)(2), an explanation of why the permit term or condition should be revised is detailed below.

MEA requests the following changes to Minor Permit No. AQ1086MSS03. To avoid conflicts between the minor permit and Title V operating permit, MEA requests that the changes be incorporated into the Title V operating permit via integrated review. Requested changes to the Title I permit as well as changes requested to Title V Operating Permit No. AQ1086TVP02 are identified as follows:

Request No.	Condition No.	Requested Revision
Minor Permit No. AQ1086MSS03		
1	5	Condition 5 is an operational hour limit on EU IDs 1 through 10 when firing ultra-low sulfur diesel (ULSD) exclusively. The limit allows the source to avoid classification as a Prevention of Significant Deterioration (PSD) major facility. In lieu of the operational hour limit, MEA requests a NO_X and PM_{10} emission limit of 220 tons per 12-month rolling period for EU IDs 1 through 10. Limiting NO_X and PM_{10} emissions will restrict the emissions of CO, $PM_{2.5}$, and VOC since NO_X and PM_{10} are the worst-case pollutants. MEA is required to conduct annual source testing for NO_X when burning natural gas fuel as required by 40 CFR 60 Subpart JJJJ and its custom monitoring waiver. It also conducted a one-time PM source test when burning natural gas fuel for emissions factor verification as required by Permit No. AQ1086MSS02. If any engine becomes subject to 40 CFR 60 Subpart IIII (i.e., if it burns 2 percent or more diesel on a total energy basis in a year), it

Request No.	Condition No.	Requested Revision
		will switch from a spark ignition engine to a compression ignition engine and will be required to conduct annual source testing for NO_X and PM when burning diesel fuel under 40 CFR 60 Subpart IIII. Applicability may switch year to year depending on the diesel fuel consumption for each engine. These emissions factors can be used to track NO_X and PM_{10} emissions accordingly. The proposed revised Condition 5 is as follows:

5. NO_X and PM_{10} Emission Limits for EU IDs 1 through 10: The Permittee shall limit NO_X and PM_{10} emissions from EU IDs 1 through 10 combined to no more than 220 tons per 12-month rolling period, for each pollutant. Monitor, record, and report as follows:

5.1 Install and maintain a non-resettable hour meter on each of EU IDs 1 through 10.

5.2 Monitor and record the hours of operation each month for each of EU IDs 1 through 10 when firing ULSD exclusively and when firing natural gas.

5.3 By the end of each calendar month, calculate and record the NO_X and PM_{10} emissions for each of EU IDs 1 through 10 for the previous month using hour data collected in Condition 5.2 and emissions factors below:

EU IDs	NO_X Emission Factor	PM_{10} Emission Factor
EU IDs 1-10 (natural gas)	1.56 lb/hr [1]	0.48 lb/hr [2]
EU IDs 1-10 (ULSD exclusively)	19.95 lb/hr [3]	10.92 lb/hr [3]

Table Notes:

[1] Worst-case emissions factor from the 2024 source test.

[2] Worst-case emissions factor from the 2015 source test.

[3] Manufacturer data.

5.4 After Department approval of source test results from source tests conducted as required by the applicable operating permit issued to the source under 18 AAC 50 and AS 46.14.130, use the new emission factor retroactive to the date of the source test in lieu of the emission factor in Condition 5.3. If the source test is serving to provide results for representative units, ensure the use for all representative units.

5.5 By the end of each calendar month, calculate and record the combined NO_X and PM_{10} emissions for EU IDs 1 through 10 for the previous 12-month period.

5.6 Report in the operating report under Condition 21 the combined 12-month rolling NO_X and PM_{10} emissions for EU IDs 1 through 10 for each month of the reporting permit.

5.7 Notify the Department under Condition 20 if the consecutive 12-month combined NO_X emissions or PM_{10} emissions for EU IDs 1 through 10 exceed 220 tons.

Request No.	Condition No.	Requested Revision
2	8	Condition 8 includes operational parameters for Selective Catalytic Reduction (SCR) and Catalytic Oxidation (CATOX) used on EU IDs 1 through 10 to reduce emissions of NO_X, CO, VOC, and HAPs. MEA may need to change the SCR reagent and/or reagent rate of injection. In order to allow this change without a new permit action, MEA requests the following language (shown in underlined text) be added to Condition 8. Because MEA is required to conduct annual NO_X source testing under 40 CFR 60 Subpart JJJJ or Subpart IIII, any changes to emissions factors caused by changes to the reagent and/or reagent injection rate will be accounted for. 8.1 For the combined control equipment[1], while operating on natural gas, monitor and record hourly: a. the rate of injection of the reducing aqueous ammonia reagent into the flue gas leaving the emission unit. The 3-hour rolling average ammonia injection rate shall be no less than 1.0 gallons per hour (gal/hr) and no more than 38.5 gal/hr[2], except during startup and shutdown. Changes to the reagent and/or reagent rate of injection can be made after Department approval provided the request is accompanied by manufacturer or vendor specifications.
Operating Permit No. AQ1086TVP02		
3	13	Revise Condition 13 of Permit No. AQ1086TVP02 as specified in Request No. 1.
4	16	Revise Condition 16 of Permit No. AQ1086TVP02 as specified in Request No. 2.
5	28	MEA requests the following language (shown in underlined text below) be added to Condition 28 to account for the potential for EU IDs 1 through 10 to be subject to 40 CFR 60 Subpart IIII as compression ignition engines in lieu of 40 CFR 60 Subpart JJJJ for spark ignition engines: **28.** For EU IDs 11, 12, and 18, listed in Table A, the Permittee shall comply with the applicable requirements in 40 CFR 60 Subpart IIII for stationary compression ignition (CI) internal combustion engine (ICE) whose construction commences after July 11, 2005 where the stationary CI ICE is manufactured after April 1, 2006 (emergency units, EU IDs 12 and 18) and manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006 (EU ID 11). For EU IDs 1 through 10, the Permittee shall comply with the applicable requirements in 40 CFR 60 Subpart IIII for non-emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder if it operates as follows. If any of EU IDs 1 through 10 use an annual average ratio of greater than or equal to 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis, it will be subject to the requirements of Subpart IIII in Condition 28 for CI internal combustion engines for the subsequent year; during this period, compliance with Condition

Request No.	Condition No.	Requested Revision
		29 as a stationary spark ignition (SI) internal combustion engine will not be required for that unit. The other applicable provisions to incorporate into Condition 28 for EU IDs 1 through 10 are: 40 CFR 60.4204(c)(2), 4204(c)(4), 4206, 4207(d), 4211(d), 4213, 4214(a), 4214(f), and 4214(g).
6	29	MEA requests the following language (shown in underlined text below) be added to Condition 29 to account for the potential for EU IDs 1 through 10 to be subject to 40 CFR 60 Subpart IIII as compression ignition engines in lieu of 40 CFR 60 Subpart JJJJ for spark ignition engines: **29.** For EU IDs 1 through 10, the Permittee shall comply with all applicable requirements of NSPS Subpart JJJJ for stationary spark ignition (SI) internal combustion engine whose construction, modification, or reconstruction commences after June 12, 2006. If any of EU IDs 1 through 10 use an annual average ratio of greater than or equal to 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis, it will be subject to the requirements of NSPS Subpart IIII in Condition 28 for CI internal combustion engines for the subsequent year; during this period, compliance with this condition will not be required for that unit.
7	Table B	Remove the permit shield for 40 CFR 68 Subpart C. MEA may become subject to 40 CFR 68, Chemical Accident Prevention Provisions, if it stores more than 20,000 pounds of aqueous ammonia with a concentration of 20 percent or greater. Although MEA does not currently use aqueous ammonia of this concentration, it would like to shield removed such that it can make the change if necessary.
8	New Condition	If MEA changes to an aqueous ammonia concentration of 20 percent or greater and stores more than 20,000 pounds, it would be required to comply with applicable requirement of 40 CFR 68. Please add the following condition: **40 CFR Part 68 Chemical Accident Prevention Provisions** **#.** If storing aqueous ammonia concentration of 20 percent or greater and more than 20,000 pounds, submit a compliance schedule for meeting the requirements of 40 CFR 68 by the date provided in 40 CFR 68.10(a) or; as part of the compliance certification submitted under Condition 64, a certification statement that the source is in compliance with all requirements of 40 CFR 68, including the registration and submission of the risk management plan (RMP).

18 AAC 50.540(k)(3)

Per 18 AAC 50.540(k)(3), an explanation of the effect of revising the permit term or condition on the elements listed below is detailed below:

- Emissions: Emissions calculations are provided in Attachment A. As a result of the revisions, the project will result in an increase in potential emissions of oxides of nitrogen (NO_X) that exceed the minor permit threshold in 18 AAC 50.502(c)(3)(A)(iii).

- Other Permit Terms: The revisions will change the stationary source's assessable potential to emit, as referenced in Condition 2.1 of Permit No. AQ1086MSS03 and Condition 40.1 of Permit No. AQ1086TVP02. No other permit terms are affected by the revisions above other than condition numbering.

- Underlying Ambient Demonstration (if any): Pursuant to 18 AAC 50.540(c)(2)(A), an ambient air quality analysis (dispersion modeling) was conducted to demonstrate compliance with the Alaska Ambient Air Quality Standards (AAAQS) for nitrogen dioxide (NO_2) since NO_X emissions exceeded the minor permit threshold in 18 AAC 50.502(c)(3)(A)(iii). The dispersion modeling analysis is included in Attachment C.

- Compliance Monitoring: Insignificant changes to Title I permit compliance monitoring are requested.

18 AAC 50.540(k)(4)

Per 18 AAC 50.540(k)(4), an explanation of the conditions' effect on avoiding a permit classification is detailed below.

This application requests revisions to conditions originally established for PSD avoidance; the proposed revisions also allow MEA to avoid classification under PSD.

Attachment C

Ambient Demonstration

ATTACHMENT C: AMBIENT DEMONSTRATION

1.0 OVERVIEW

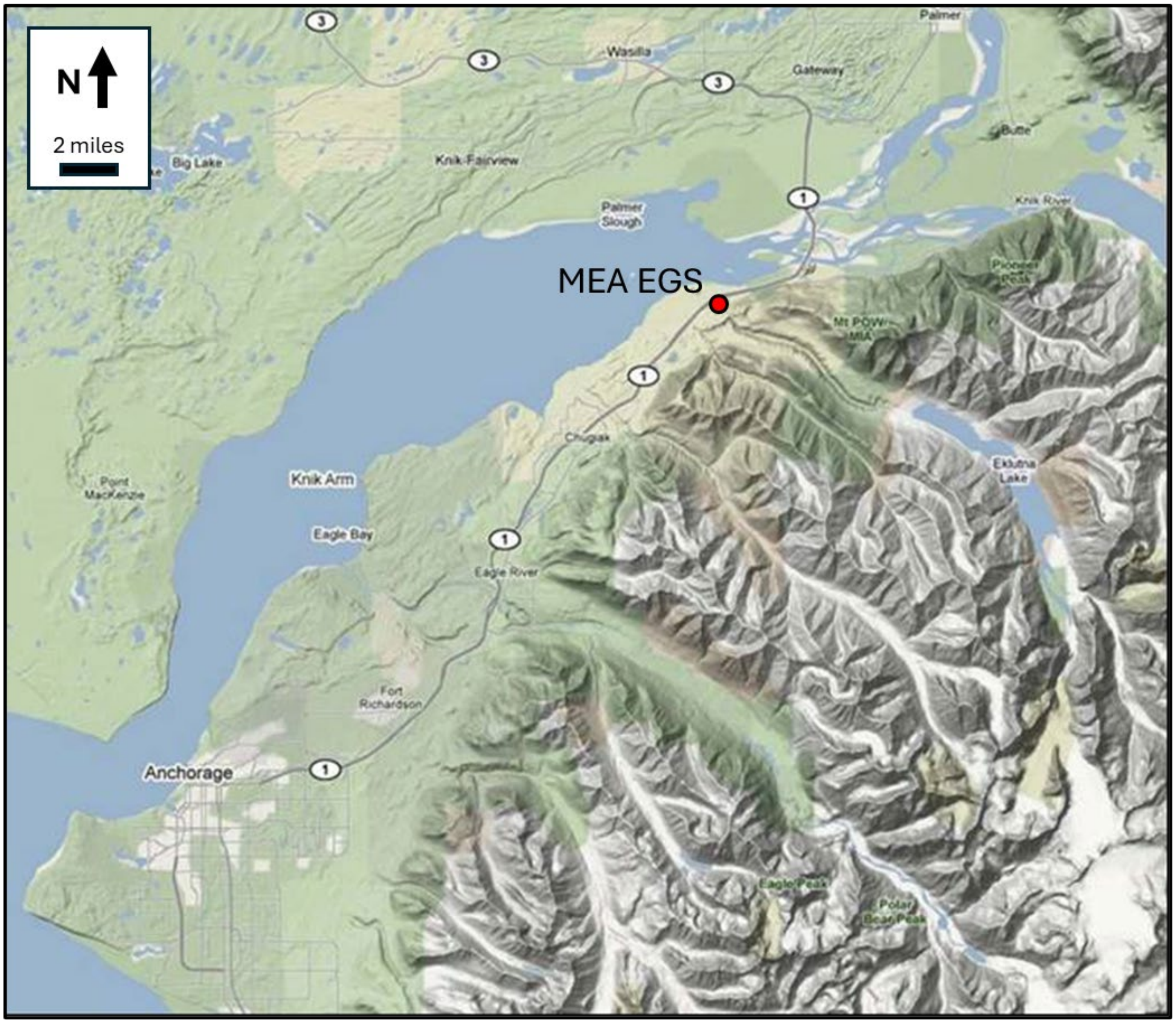
Matanuska Electric Association (MEA) currently operates the Eklutna Generation Station (EGS) under Minor Permit No. AQ1086MSS03 and Operating Permit No. AQ1086TVP02. The EGS is a baseload power plant comprised of ten stationary dual fuel-fired generator engines and associated equipment. Primary operation of the generator engines is on natural gas, but in the event of an interruption to the natural gas supply, the engines can operate solely on ultra-low sulfur diesel (ULSD) to ensure baseload power reliability. The proposed permit revisions will provide flexibility for MEA to operate the dual fuel-fired generator engines in diesel-fired mode at greater frequencies than currently authorized. This permit revision is necessary because MEA has been informed by its suppliers that delivery of natural gas will not be guaranteed on any upcoming contracts due to expected natural gas supply shortages. A map showing the location of the stationary source is provided in Figure 1-1.

Based on the potential emissions increase of nitrogen oxides (NO_X), the project triggers minor permitting requirements under 18 Alaska Administrative Code (AAC) 50.502(c)(3)(A)(iii). As a result, air dispersion modeling is required to demonstrate that the stationary source will not cause or contribute to a violation of the annual average nitrogen dioxide (NO_2) Alaska Ambient Air Quality Standard (AAAQS) is required under 18 AAC 50.540(c)(2)(A). The procedures and results of the dispersion modeling analysis for the EGS are described below. The air quality modeling results demonstrate that the project will not result in ambient air quality impacts that will exceed the annual average NO_2 AAAQS.

2.0 MODELING METHODOLOGY

Dispersion modeling was conducted to estimate the potential ambient air quality impacts associated with the operation of the equipment associated with the EGS. The air quality analysis used the latest version of the AERMOD (24142) air dispersion model, per 40 Code of Federal Regulation (CFR) 51, Appendix W. The latest versions of AERMET (24142) and AERSURFACE (24142) were used to prepare meteorological data and atmospheric stability and meteorology inputs for use in AERMOD. The latest version of the AERMOD terrain data pre-processor, AERMAP (24142), was used to process source elevations, receptor elevations, and hill height scales from U.S. Geological Survey (USGS) digital national elevation data (NED). The most recent version of the Building Profile Input Program with Plume Rise Model Enhancements (BPIPPRM 04274) was used to model the effects of building downwash on the dispersion of emissions. All model input and output files prepared for this analysis are provided in Attachment E.

Figure 1-1. Project Location Map



2.1 MODEL EMISSIONS UNIT INPUT PARAMETERS

No construction activities are associated with this minor permit application. As such, the dispersion modeling analysis was based on the EGS operations scenario.

Table 2-1 provides the locations, physical parameters, and emission rates for the explicitly modeled EGS emissions units (EUs). All EUs were modeled as point sources. All EU exhaust points and structures used for AERMOD input were referenced to the Universal Transverse Mercator (UTM) coordinate system and reference a base elevation of 9.41 meters (m). The firewater pump engine (EU ID 11) was modeled with a horizontal uncapped stack and the natural gas fuel heater (EU ID 17) was modeled with a vertical capped stack. The remaining EUs were each modeled as a single point source with a vertical uncapped stack.

The respective modeled EU locations, physical parameters, and NO_X emission rates are based upon “worst-case” emission scenarios that were generally determined from manufacturer data or source testing. For the ten generator engines (EU IDs 1 through 10), the modeled NO_X emissions rates are representative of unlimited operations rather than utilizing the emissions cap of 220 tons per year (tpy), combined. In lieu of performing a load screening analysis, the modeled exhaust temperature and exhaust velocity input parameters for the ten generator engines (EU IDs 1 through 10) are based on the worst-case values for diesel or natural gas combustion.

Table 2-1. EGS Model Parameters and Emission Rates

Emissions Unit		Exhaust Stack Location UTM		Exhaust Stack Parameters				Emission Rates
Model ID	Description	X (m)	Y (m)	Height (m)	Temp (K)	Velocity (m/s)	Diameter (m)	Long-Term (LT) NO_X (g/s)
GENENG01	Generator Engine	375,146.93	6,816,225.02	30.00	628	14.93	1.629	2.51E+00
GENENG02	Generator Engine	375,151.50	6,816,225.02	30.00	628	14.93	1.629	2.51E+00
GENENG03	Generator Engine	375,156.08	6,816,225.02	30.00	628	14.93	1.629	2.51E+00
GENENG04	Generator Engine	375,146.93	6,816,220.45	30.00	628	14.93	1.629	2.51E+00
GENENG05	Generator Engine	375,151.50	6,816,220.45	30.00	628	14.93	1.629	2.51E+00
GENENG06	Generator Engine	375,156.08	6,816,220.45	30.00	628	14.93	1.629	2.51E+00
GENENG07	Generator Engine	375,151.50	6,816,299.70	30.00	628	14.93	1.629	2.51E+00
GENENG08	Generator Engine	375,156.08	6,816,299.70	30.00	628	14.93	1.629	2.51E+00
GENENG09	Generator Engine	375,151.50	6,816,295.13	30.00	628	14.93	1.629	2.51E+00
GENENG10	Generator Engine	375,156.08	6,816,295.13	30.00	628	14.93	1.629	2.51E+00
FW_PUMP1	Firewater Pump Engine	375,086.89	6,816,209.78	2.90	780	15.22	0.203	8.43E-03
EBSENG1	Black Start Generator	375,145.41	6,816,285.98	3.20	750	109.73	0.203	1.23E-01
AUXBOIL1	Auxiliary Boiler	375,197.22	6,816,191.50	18.10	444	7.98	0.610	1.70E-01
AUXBOIL2	Auxiliary Boiler	375,197.22	6,816,189.97	18.10	444	7.98	0.610	1.70E-01
FG_HEAT1	Natural Gas Fuel Heater	375,035.68	6,816,322.56	4.30	480	4.73	0.597	9.52E-02
EBSENG2	Black Start Generator	375,145.41	6,816,266.17	3.20	750	109.73	0.203	1.23E-01

2.2 OFFSITE MODEL EMISSIONS UNIT INVENTORY

For a cumulative ambient air quality impact assessment, the potential emissions from the project EU inventory and off-site stationary sources were modeled to compute a cumulative impact. Section 8.2 of 40 CFR 51, Appendix W indicates that off-site sources that will cause a significant concentration gradient in the vicinity of the EGS stationary source should be explicitly modeled.

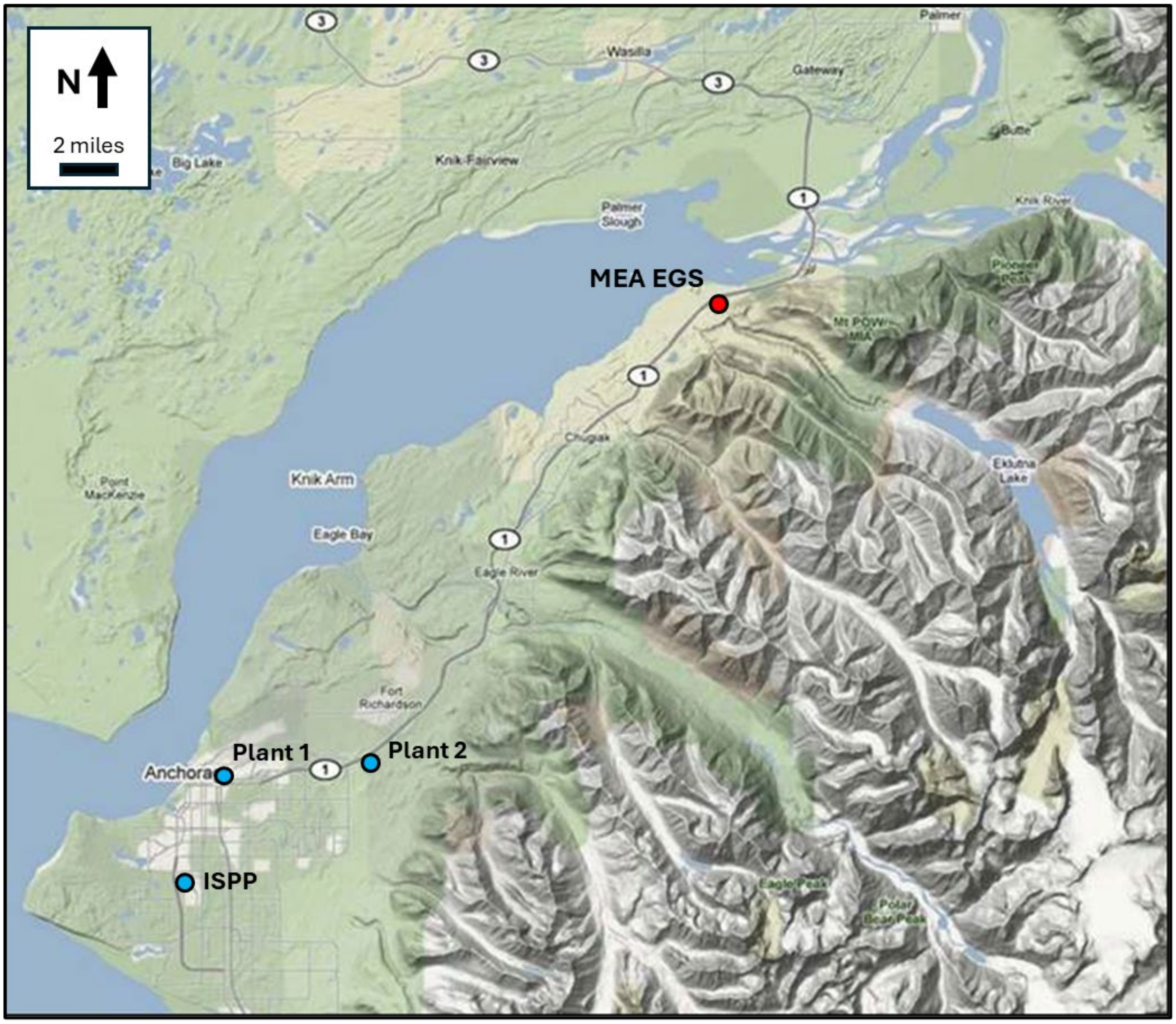
Figure 2-1 shows the locations of the EGS and the modeled off-site sources. The modeled off-site source inventory was based on the proximity of off-site sources to the EGS and whether a certain off-site source has the potential to cause a significant concentration gradient that will overlap with the predicted impacts from the EGS EUs. Based on these criteria, the Chugach Electric Association (CEA) Hank Nikkels Plant One (Plant One), the CEA George Sullivan Generation Plant Two (Plant Two), and the CEA International Station Power Plant (ISPP) were included as off-site sources in the cumulative ambient air quality impact assessment. These off-site stationary sources were each modeled as a single point source.

The modeled EU locations, stack parameters, and modeled annual average NO_2 emission rates for the off-site sources in the cumulative impact analysis are based on the following data sources:

- CEA Plant One stationary source was modeled based on information in the Statement of Basis (SOB) for Air Quality Operating Permit No. AQ0202TVP05 and in the stationary source's 2023 Point Source Emission Inventory.
- CEA Plant Two stationary source was modeled based on information in the Statement of Basis (SOB) for Air Quality Operating Permit No. AQ0203TVP05 and in the stationary source's 2023 Point Source Emission Inventory.
- CEA ISPP stationary source was modeled based on information in the Statement of Basis (SOB) for Air Quality Operating Permit No. AQ0164TVP05 and in the stationary source's 2023 Point Source Emission Inventory.

The resulting air pollutant concentrations from the MEA EGS and the off-site inventory were then added to a representative background NO_2 concentration and assessed against the annual NO_2 AAAQS.

Figure 2-1. Map of the EGS and Modeled Offsite Sources

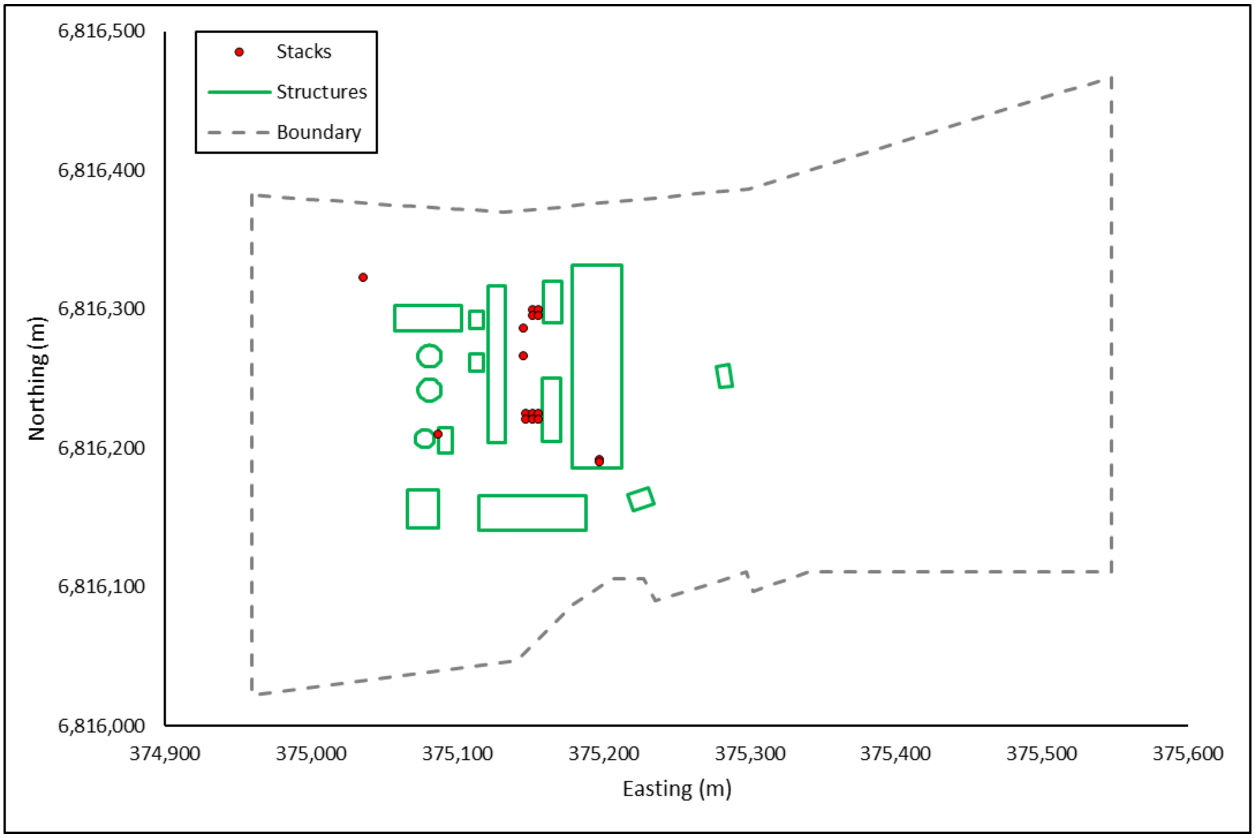


2.3 BUILDING DOWNWASH ANALYSIS

The modeling analysis follows the guidance provided in the EPA *Guidelines for Determination of Good Engineering Practice Stack Height* (EPA-450/4-80-023R, June 1985). The latest version of BPIPPRM (04274) was used to process building downwash. Building coordinates and heights for each structure that could influence a modeled emission unit were entered into BPIPPRM and the output dimensions were used to ensure that no stack exceeds good engineering practice (GEP) stack height and to provide direction-specific downwash dimensions to the AERMOD model.

Figure 2-2 provides a depiction of the EGS facility structures and EUs. The buildings and structures used in the downwash analysis are outlined in green and the EU exhaust stack locations are depicted with red circles. The ambient air boundary is depicted with a dashed grey line. All building and emission unit locations are referenced to UTM Zone 6 coordinates. BPIPPRM input and output files prepared for the modeling analysis are provided in Attachment E.

Figure 2-2. EGS Facility Layout and EU Stack Locations



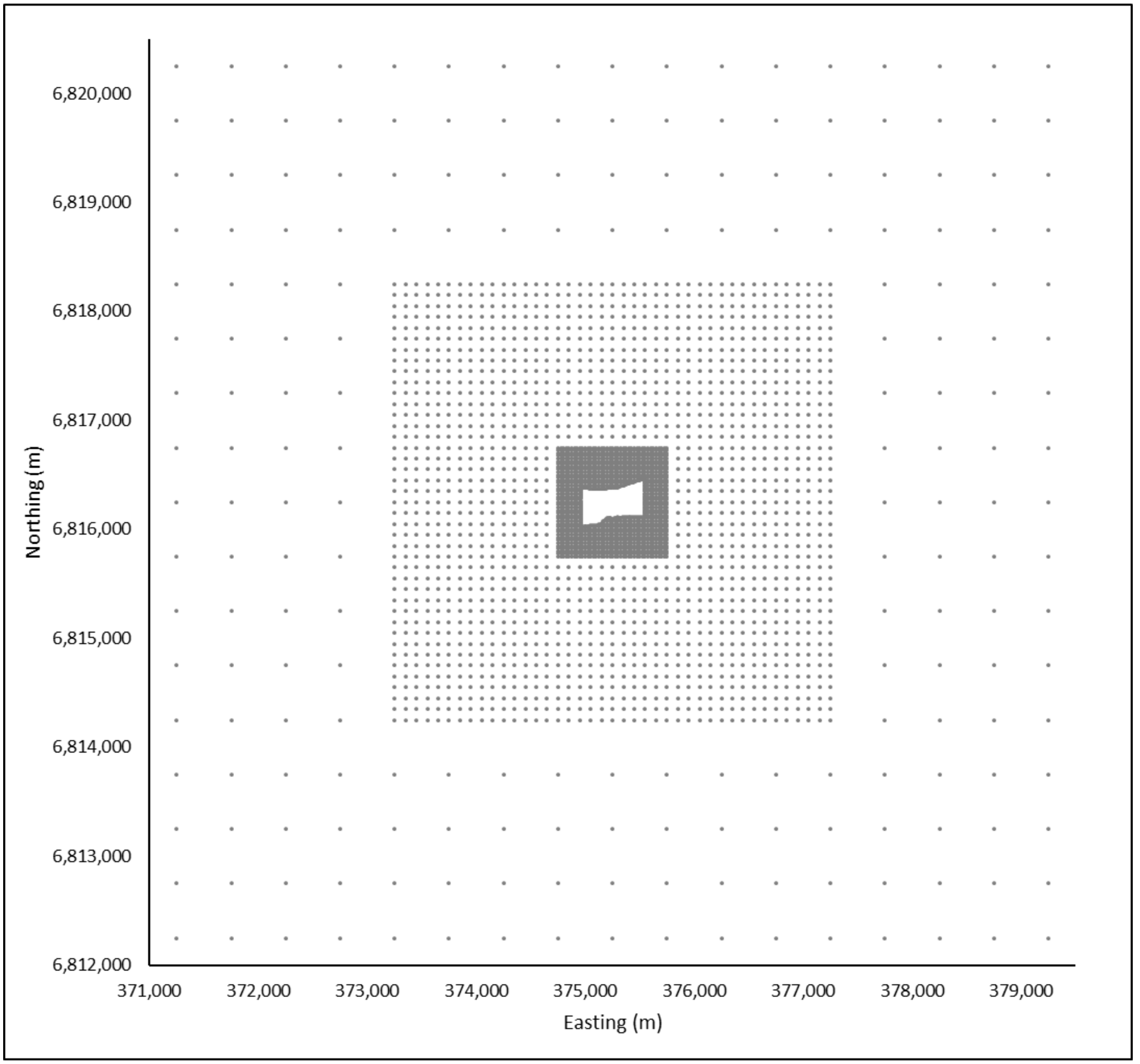
2.4 MODEL RECEPTORS AND TERRAIN

EPA defines ambient air as that portion of the atmosphere, external to buildings, to which the general public has access (40 CFR Part 50.1). For the purposes of modeling stationary source emissions, the area to which an owner or operator of a stationary source controls public access via a physical barrier is not considered ambient air. Accordingly, model receptors were placed along the EGS fence line to represent the ambient air boundary. The EGS facility is fully fenced and access through the front gate is restricted to MEA employees and contractors.

The AERMOD terrain data pre-processor, AERMAP, was used to calculate discrete receptor elevations and hill height scales from a 1/3 arc-second resolution DEM file acquired from the USGS.

Figure 2-3 depicts all receptor fields used for the modeling analyses. The receptor fields were developed to capture maximum impacts and to evaluate impacts in the areas distant from the EGS. The ambient air boundary receptors are composed of receptors spaced apart by less than 25 m. The near field is composed of receptors spaced apart by 25 m within a 1 square kilometer (km^2) area centered over the EGS. The mid field receptors are spaced apart by 100 m within a 16 km^2 area. The far field receptor grid is composed of adjacent receptors spaced apart by 500 m within a 64 km^2 area. Maximum pollutant impacts were predicted within the near field receptor grid. As a result, the near field grid did not need to be adjusted because the maximum pollutant concentrations had been correctly identified. AERMAP input and output files prepared for the modeling analysis are provided in Attachment E.

Figure 2-3. Full Model Receptor Grid



2.5 NO_2 MODELING APPROACH

Because the AAAQS for NO_X are expressed in terms of NO_2, additional calculations and modeling approaches are used to determine NO_2 impacts from modeled NO_X emissions. Typically, a multi-tiered screening approach would be used for the modeling analysis that follows the guidance in 40 CFR 51, Appendix W, Section 4.2.3.4 *Models for Nitrogen Dioxide.* The first tier (Tier 1) screening method assumes all emitted NO_X is converted to NO_2. Because the Tier 1 approach proved to be overly conservative, the second level screening approach (Tier 2) was selected.

The Tier 2 screening approach multiplies the Tier 1 results by the Ambient Ratio Method 2 (ARM2), which provides estimates of representative equilibrium ratios of NO_2-to-NO_X values based on ambient levels of NO_2 and NO_X derived from national data from the EPA.

2.6 AERMET METEOROLOGICAL DATA

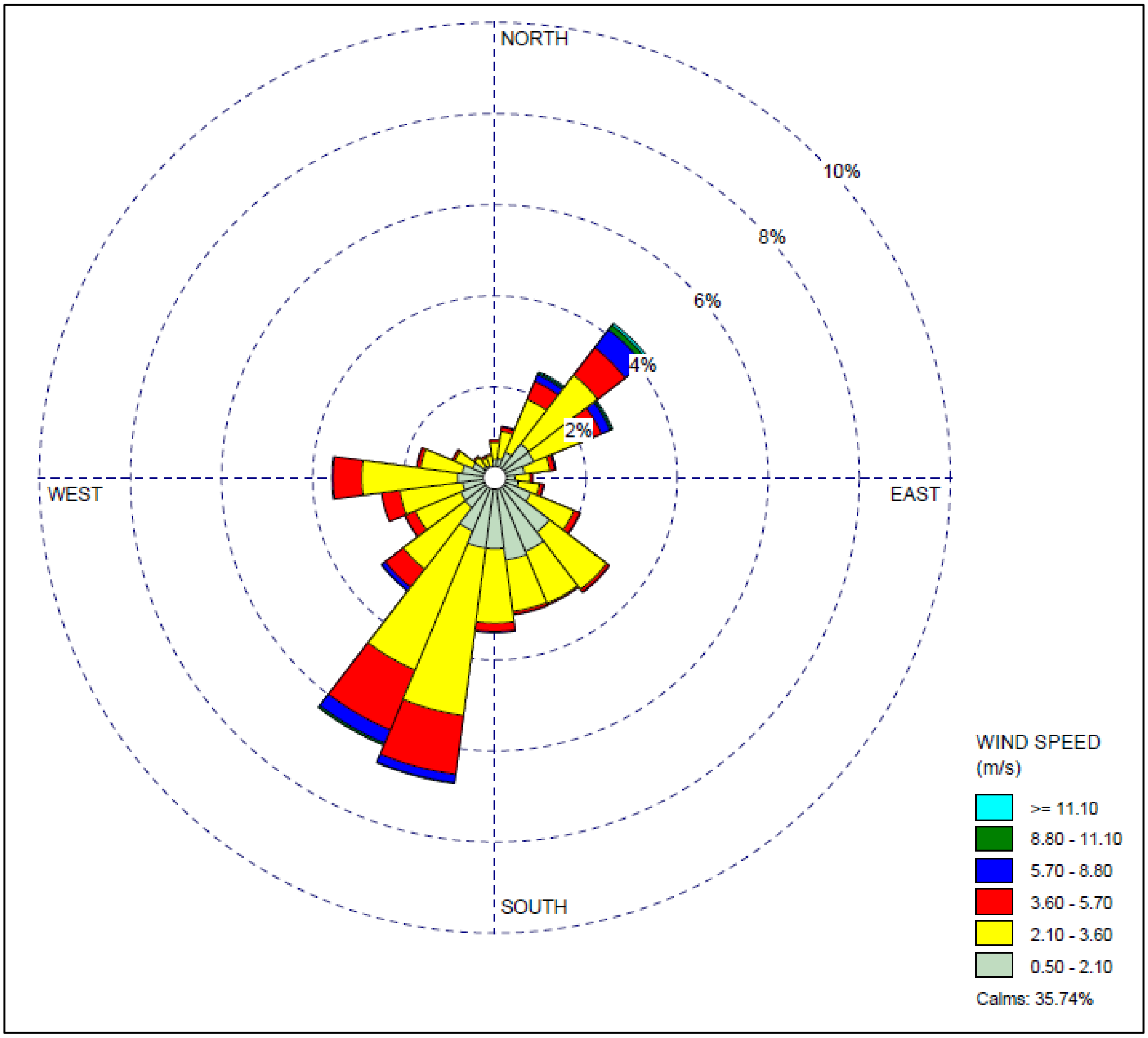
Per 40 CFR 51, Appendix W, Section 8.4.2(e), five years of adequately representative meteorological data comparable to National Weather Service meteorological data were used to estimate annual NO_2 impacts. Hourly surface meteorological data collected during calendar years 2019 through 2023 at the Birchwood Airport and concurrent twice-daily upper air meteorological data collected by the National Weather Service at Anchorage, Alaska were processed using AERMET (24142). In a memo dated May 29, 2024, ADEC approved the use of the five-year Birchwood Airport meteorological data set to represent meteorological conditions at the MEA EGS after considering geographical and climatological conditions of the Project area.

The meteorological data are comprised of hourly averages of meteorological monitoring parameters including wind speed, wind direction, temperature, and cloud cover observations. Table 2-2 gives the hourly data capture statistics for each of the meteorological parameters provided as inputs and processed by AERMET. The Birchwood Airport wind data are collected at a height of 7.0 meters above grade. Figure 2-4 provides a wind rose based on the wind data collected at the Birchwood Airport during the 2019 through 2023 monitoring years.

Table 2-2. Hourly Data Capture Percentages for Birchwood Airport

Year	Temperature	Wind Speed	Wind Direction	Cloud Cover
2019	98.7%	98.7%	93.0%	98.7%
2020	99.8%	99.8%	94.4%	99.9%
2021	99.7%	99.1%	94.0%	98.6%
2022	99.4%	99.4%	93.3%	99.4%
2023	99.9%	99.2%	95.5%	99.8%

Figure 2-4. Birchwood Airport Monitoring Station Wind Rose Calendar Years 2019 through 2023



The AERMET algorithms process upper air and surface meteorological data with site-specific geophysical inputs to calculate the atmospheric boundary layer parameters that are then supplied to AERMOD for use in the air dispersion model algorithms. The geophysical parameters are albedo, Bowen ratio, and surface roughness length. The procedures used to determine these input parameters are outlined in the EPA AERMOD Implementation Guide, Section 3.1.3 (November 2024). The procedures for determining the geophysical input parameters are summarized as follows:

- Albedo is based on a simple unweighted arithmetic mean for a representative domain defined by a 10 kilometer (km) by 10 km grid with a resolution of 1 km^2 and centered on the surface measurement site.

- Bowen Ratio is based on a simple unweighted geometric mean for the same representative domain that is used to define the site-specific albedo.
- Surface Roughness Length is based on an inverse-distance weighted geometric mean for a default upwind distance of 1 km relative to the surface meteorological measurement site. The surface roughness length varies by sector and is based on twelve sectors, each with a sector width of 30 degrees, to account for variations in land cover near the meteorological measurement site.

Per 40 CFR 51, Appendix W, Section 8.4.2(b) the latest version of AERSURFACE (24142) was used to process 2016 National Land Classification Data (2016 NLCD) obtained from the USGS to determine albedo, Bowen ratio and surface roughness length values for processing the 2019 through 2023 surface and upper air meteorological data sets with AERMET.

The AERMET geophysical input parameters are also seasonally dependent. AERMET uses a significantly different definition of the monthly make-up of the seasons than the conditions experienced in Southcentral Alaska. These geophysical parameters were input in AERMET per month to reflect the seasonal patterns of Southcentral Alaska. The AERSURFACE User Guide recommends using a 30-year climatological record to determine the monthly surface moisture condition (wet, dry, or average). The nearest representative station with the necessary monthly records available, Eklutna Water Treatment Plant (WTP) weather station, has 24 years of records available. As such, the monthly surface moisture condition was determined using the AERSURFACE suggested percentiles for a 24-year climatological record. The following definitions of the seasons are based on climate records for Eklutna, AK and have been approved by ADEC for prior permit activities at EGS (e.g., Permit No. AQ1086MSS01).

- Spring (April and May): vegetation is emerging or partially green, the period when mean daily low temperatures rise above 32 degrees Fahrenheit (ºF).
- Summer (June, July, and August): vegetation is most lush, daylight hours are at annual maximum, and daily low temperatures are well above 32 ºF.
- Autumn (September and October): below-freezing temperatures are common, deciduous trees transition from shedding leaves to becoming leafless, grasses are brown, and little or no snow is present.
- Winter (November, December, January, February, and March): daily high temperatures rarely exceed 32 ºF, lakes and streams are frozen, and ground is covered with snow and ice.

AERSURFACE and AERMET input and output files prepared for the modeling analysis are provided in Attachment E.

2.7 BACKGROUND AMBIENT AIR DATA

Background ambient air quality data are required in a cumulative impact analysis to represent the contribution of ambient air pollutant concentrations from non-modeled sources (40 CFR 51, Appendix W, Section 8.3.1). The ambient air pollutant concentrations from the Fairbanks NCore monitoring site were used to represent the contribution of ambient air pollutant levels from non-modeled sources of NO_2. In an email dated November 27, 2024, ADEC approved the use of the 3-year average of the annual mean NO_2 concentration from the 2018 NCore NO_2 dataset to conservatively represent the background ambient annual NO_2 level at the EGS. The ambient air pollution concentrations are summarized in Table 2-3 and have been reviewed by ADEC and found to meet Prevention of Significant Deterioration (PSD) data quality standards.

Table 2-3. Summary of Ambient Background Concentrations

Pollutant	Averaging Period	Background Concentration (μg/m^3)	AAAQS (μg/m^3)
NO_2	Annual	23.56	100

3.0 CRITERIA POLLUTANT DISPERSION MODEL ANALYSIS RESULTS

Table 3-1 provides the maximum modeled ambient air quality impact based on the EGS ambient demonstration. Table 3-1 shows that the maximum modeled annual average NO_2 impact is 48.65 micrograms per cubic meter (μg/m^3). Adding the annual average NO_2 background level to the maximum modeled annual average ambient concentration results in an annual average NO_2 concentration equal to 72.21 μg/m^3, which is 72.2 percent of the annual average NO_2 AAAQS.

Table 3-1. EGS Cumulative Impact Analysis Results Including Offsite Sources

Air Pollutant	Averaging Period	Maximum Modeled Impact [1] (μg/m^3)	Background Concentration (μg/m^3)	Maximum Cumulative Impact (μg/m^3)	AAAQS (μg/m^3)	Percent of AAAQS
NO_2	Annual	48.65	23.56	72.21	100	72.2

Notes:
[1] Based on the modeled highest annual average NO_2 impact for all model years.

4.0 REFERENCES

ADEC, *ADEC Modeling Review Procedures Manual*, October 8, 2018.

ADEC, Title 18 Alaska Administrative Code, *Chapter 50, Air Quality Control*, as amended through December 14, 2024.

EPA, Appendix W to Part 51, Title 40 – *Guideline on Air Quality Models*, Revised January 28, 2025, from: https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-51/appendix-Appendix%20W%20to%20Part%2051

EPA, *Pre-Generated Data Files - Annual Summary Data*, Revised November 19, 2024, from: https://aqs.epa.gov/aqsweb/airdata/download_files.html#Annual

EPA, *Guidelines for Determination of Good Engineering Practice Stack Height*, EPA-450/4-80-023R, Office of Air Quality Planning and Standards, Research Triangle Park, N.C., June 1985.

EPA, *User's Guide for the AMS/EPA Regulatory Model (AERMOD)*, EPA-454/B-24-007, Office of Air Quality Planning and Standards, Research Triangle Park, N.C., November 2024.

EPA, *User's Guide for the AERMOD Meteorological Preprocessor (AERMET)*, EPA-454/B-24-004, Office of Air Quality Planning and Standards, Research Triangle Park, N.C., November 2024.

EPA, *User's Guide for the AERMOD Terrain Preprocessor (AERMAP)*, EPA-454/B-24-008, Office of Air Quality Planning and Standards, Research Triangle Park, N.C., November 2024.

EPA, *User's Guide for AERSURFACE Tool*, EPA-454/B-24-003, Office of Air Quality Planning and Standards, Research Triangle Park, N.C., November 2024.

EPA, *Revision to the Guideline on Air Quality Model: Enhancements to the AERMOD Dispersion Modeling System and Incorporation of Approaches to Address Ozone and Fine Particulate Matter*; Final Rule, 40 CFR 51, Appendix W, Office of Air Quality Planning and Standards, Research Triangle Park, N.C., January 2017

EPA, *Clarification on the Use of AERMOD Dispersion Modeling for Demonstrating Compliance with the NO_2 National Ambient Air Quality Standard*, Memorandum, EPA Model Clearinghouse, Office of Air Quality Planning and Standards, Research Triangle Park, N.C., September 2014.

NRCC, xmACIS Version 1.0.69k, Released February 11, 2025, from: https://xmacis.rcc-acis.org/

Attachment D

Permits

DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY CONTROL MINOR PERMIT

Permit No. AQ1086MSS03 **Final - November 06, 2015**
Rescinds Minor Permit No. AQ1086MSS02

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. AQ1086MSS03 to the Permittee listed below.

Permittee:	**Matanuska Electric Association** PO Box 2929 163 E. Industrial Way Palmer, Alaska 99645
Owner/Operator:	Same as Permittee
Stationary Source	**Eklutna Generation Station**
Location:	Latitude: 61° 27' 34.5" N; Longitude: 149° 20' 33.9" W
Physical Address:	28705 Dena'ina Elders Road, Chugiak, Alaska 99567
Permit Contact:	Traci Bradford, (907) 761-9374; traci.bradford@mea.coop
Project:	Revise Emission Control Operating Parameters

This permit is classified under 18 AAC 50.508(6) for revising or rescinding the terms and conditions of a Title I permit. This permit also carries forward the classifications of 18 AAC 50.502(c)(1) and 18 AAC 50.508(5) from Permit No. AQ1086MSS01. The permit satisfies the obligation of the Permittee to obtain a minor permit under 18 AAC 50. As required by AS 46.14.120(c), the Permittee shall comply with the terms and conditions of this permit

for

John F. Kuterbach, Manager
Air Permits Program

Table of Contents

Section 1. Emission Inventory

1. Emission Unit Authorization. The Permittee is authorized to install and operate emission units (EUs) listed in Table 1. Except as noted elsewhere in the permit, the information in Table 1 is for information purposes only. The specific unit descriptions 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 a replacement emission unit, including any applicable minor or construction permit requirements.

Table 1 –Emission Unit Inventory

EU ID	Description	Make / Model	Rating	Fuel Type	Install Date
1	Generator Engine	Wartsila 18V50DF	17.1 MW	NG/ULSD	March 2015
2	Generator Engine	Wartsila 18V50DF	17.1 MW	NG/ULSD	March 2015
3	Generator Engine	Wartsila 18V50DF	17.1 MW	NG/ULSD	March 2015
4	Generator Engine	Wartsila 18V50DF	17.1 MW	NG/ULSD	March 2015
5	Generator Engine	Wartsila 18V50DF	17.1 MW	NG/ULSD	March 2015
6	Generator Engine	Wartsila 18V50DF	17.1 MW	NG/ULSD	March 2015
7	Generator Engine	Wartsila 18V50DF	17.1 MW	NG/ULSD	February 2015
8	Generator Engine	Wartsila 18V50DF	17.1 MW	NG/ULSD	February 2015
9	Generator Engine	Wartsila 18V50DF	17.1 MW	NG/ULSD	February 2015
10	Generator Engine	Wartsila 18V50DF	17.1 MW	NG/ULSD	February 2015
11	Firewater Pump	John Deere JU6H-UFADN0	197 hp	ULSD	October 2014
12	Black Start Generator	Cummins 1000DQFAD	1,490 hp	ULSD	April 2015
13	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	15.75 MMbtu/hr	NG/ULSD	October 2014
14	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	15.75 MMbtu/hr	NG/ULSD	October 2014
15	Diesel Storage Tank	Rockford Corporation	436,842 gal	Diesel	November 2014
16	Diesel Storage Tank	Rockford Corporation	436,842 gal	Diesel	November 2014
17	NG Fuel Heater	ETI	7.0 MMBtu/hr	Natural Gas	TBD
18	Black Start Generator	Cummins 1000DQFAD	1,490 hp	ULSD	April 2015

Table Notes:
NG / ULSD: Natural Gas / Ultra Low Sulfur Diesel
TBD: To Be Determined

1.1 The Permittee shall maintain the equipment listed in Table 1 according to the manufacturers’ or operator’s maintenance procedures and shall keep copies of the maintenance procedures.

Section 2. Emission Fees

2. **Assessable Emissions.** The Permittee shall pay 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 assessable emission fee rate is set out in 18 AAC 50.410(b). The Department will assess fees per ton of each air pollutant that the stationary source emits or has the potential to emit in quantities greater than 10 tons per year (tpy). The quantity for which fees will be assessed is the lesser of:

2.1 the stationary source's assessable potential to emit of 795 tpy; or

2.2 the stationary source's projected annual rate of emissions that will occur from July 1st to the following June 30th, 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**.**

3. **Assessable Emission Estimates.** Emission fees will be assessed as follows:

3.1 no later than March 31st of each year, the Permittee may submit an estimate of the stationary source's assessable emissions to the Department, 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

3.2 if no estimate is submitted on or before March 31st of each year, emission fees for the next fiscal year will be based on the potential to emit set forth in Condition 2.1.

4. **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 through 405.

Section 3. Requirements to Avoid Classification under PSD

5. **Operation Hour Limits for EU IDs 1 through 10:** The Permittee shall limit the combined hours of operation of EU IDs 1 through 10 to no more than 1,680 hours per 12-month rolling period when firing ultra-low sulfur diesel (ULSD) exclusively.

5.1 The Permittee shall burn only natural gas and ULSD in EU IDs 1 through 10.

5.2 Install and maintain a non-resettable hour meter on each of EU IDs 1 through 10.

5.3 Monitor and record the hours of operation each month for each of EU IDs 1 through 10 when firing ULSD exclusively.

5.4 By the end of each calendar month, calculate and record the combined hours of operation for EU IDs 1 through 10 when firing ULSD exclusively during the previous month, then calculate the 12-month rolling combined hours for EU IDs 1 through 10 when firing ULSD exclusively.

5.5 Report in the operating report under Condition 21 the rolling 12-month combined hours of operation for EU IDs 1 through 10 when firing ULSD exclusively.

5.6 Notify the Department under Condition 20 if the consecutive 12-month combined hours of operation for EU IDs 1 through 10, when firing ULSD exclusively, exceed 1,680 hours.

6. **Operation Hour Limits for EU ID 11:** The Permittee shall limit the operation of EU ID 11 to no more than 500 hours per year.

6.1 Install and maintain a non-resettable hour meter on EU ID 11.

6.2 Monitor and record the monthly hours of operation for EU ID 11.

6.3 By the end of each month, calculate and record the operating hours of EU ID 11 for the previous month.

6.4 Report in the operating report under Condition 21 the rolling 12-month hours of operation for EU ID 11.

6.5 Notify the Department under Condition 20 if the rolling 12-month hours of operation for EU ID 11 exceed 500 hours.

7. **Operation Hour Limits for EU IDs 13 and 14:** The Permittee shall limit the combined hours of operation of EU IDs 13 and 14 to no more than 1,000 hours per rolling 12-month period when firing ULSD exclusively.

7.1 The Permittee shall fire only natural gas and ULSD in EU IDs 13 and 14.

7.2 Install and maintain a non-resettable hour meter on each of EU IDs 13 and 14.

7.3 Monitor and record the monthly operating hours for each of EU IDs 13 and 14 when firing ULSD exclusively.

7.4 By the end of each month, calculate and record the combined operating hours of EU IDs 13 and 14 when firing ULSD exclusively during the previous month, then calculate the 12-month rolling combined hours for EU IDs 13 and 14 when firing ULSD exclusively.

7.5 Report in the operating report under Condition 21 the rolling 12-month combined operating hours for EU IDs 13 and 14 when firing ULSD exclusively.

7.6 Notify the Department under Condition 20 if the rolling 12-month combined hours of operation for EU IDs 13 and 14, when firing ULSD exclusively, exceeds 1,000 hours.

8. Control Equipment: The Permittee shall operate and maintain a combined Selective Catalytic Reduction (SCR) and Catalytic Oxidation (CATOX) control equipment downstream of each of EU IDs 1 through 10 according to the manufacturer's instructions and as follows:

8.1 For the combined control equipment[1], while operating on natural gas, monitor and record hourly:

a. the rate of injection of the reducing aqueous ammonia reagent into the flue gas leaving the emission unit. The 3-hour rolling average ammonia injection rate shall be no less than 1.0 gallons per hour (gal/hr) and no more than 38.5 gal/hr[2], except during startup and shutdown.

b. the temperature of the flue gas leaving the combined control equipment. The 3-hour rolling average temperature of the flue gas leaving the combined control equipment shall be no less than 536°F and no more than 997°F[3], except during startup and shutdown.

c. the pressure drop across the combined control equipment. The 3-hour rolling average pressure drop shall be no less than 1.5 inches of water and no more than 10 inches of water, except during startup and shutdown.

8.2 Keep on site the necessary manufacturer-recommended spare parts, reagents, catalysts, and operation manual for the control equipment.

8.3 In case of equipment malfunction, implement manufacturer-recommended corrective actions and record:

a. complete description of the corrective action; and

b. date(s) of the corrective action

8.4 Keep records of:

a. all control equipment system repairs;

[1] SCR and CATOX with the CATOX downstream of the SCR.
[2] The minimum injection rate is from the permit application. The maximum injection rate is from the manufacturer's specifications.
[3] The temperature rates are from the manufacturer specifications.

b. hourly operating parameters established in Condition 8.1, dates and times each control equipment is started up or shut down;

c. system alarm logs including time and date of occurrence; and

d. receipts for all aqueous ammonia purchases (with dates and quantities).

8.5 Report under Condition 20 all:

a. control equipment malfunctions and associated corrective actions;

b. operating parameters that are outside the ranges in Condition 8.1; and

c. periods (starting and ending hour) during which a control equipment was not operating within the ranges established in Condition 8.1 while its associated generator was operating.

Section 4. Requirements to Avoid Classification as a HAP Major Source

9. Formaldehyde (CH_2O) Emission Limit: The Permittee shall limit CH_2O emissions from EU IDs 1 through 10 while firing natural gas to no more than 9.6 tpy during any consecutive 12 months by operating and maintaining the control equipment described in Condition 8.

Section 5. State Emission Standards

10. Visible Emissions. The Permittee shall not cause or allow visible emissions (VE), excluding condensed water vapor, emitted by EU IDs 1 through 14, 17, and 18 to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.

11. Particulate Matter: The Permittee shall not cause or allow particulate matter (PM) emitted from EU IDs 1 through 14, 17, and 18 to exceed 0.05 grains per dry standard cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.

12. Sulfur Compound Emissions: The Permittee shall not cause or allow sulfur compound emissions, expressed as SO_2, from EU IDs 1 through 14, 17, and 18 to exceed 500 ppm averaged over three hours.

12.1 The Permittee shall monitor, record, and report as described in Condition 15.

Section 6. Protection of Ambient Air Quality

13. Annual NO_2 Ambient Air Quality Protection: To protect the annual NO_2 ambient air quality standard, the Permittee shall:

13.1 For EU IDs 1 through 10, the Permittee shall maintain a release height for each stack that equals or exceeds 30.0 meters above grade.

14. Annual NO_2 and 24-hr PM-10 Ambient Air Quality Protection: To protect the annual NO_2 and 24-hr PM-10, the combined operating hours for EU IDs 12 and 18 shall not exceed 1,000 hours per rolling 12-month period.

14.1 Install and maintain a non-resettable hour meter on each of EU IDs 12 and 18.

14.2 Monitor and record the hours of operation of each emission unit and the combined hours of operation for EU IDs 12 and 18 for each month.

14.3 At the end of each month, calculate and record for the previous month, the combined hours of operation for EU ID 12 and EU ID 18 during the month, then calculate the combined 12-month rolling total hours of operation by adding the hours of operation for the previous 11 months.

14.4 Report in the operating report under Condition 21 the combined rolling 12-month hours of operation for EU IDs 12 and 18.

14.5 Notify the Department under Condition 20 should the combined consecutive 12-month operating hours for EU IDs 12 and 18 exceed 1,000 hours.

Section 7. Requirements to Avoid Minor Permitting under 18 AAC 50.502(c)(1)(c)

15. **Fuel Sulfur Requirements:** The Permittee shall monitor the sulfur content of the ULSD and hydrogen sulfide (H_2S) content of the natural gas burned as follows:

15.1 The H_2S content of the natural gas burned in EU IDs 1 through 10, 13, 14, and 17 shall not exceed 20 parts per million by volume (ppmv).

a. Monitor and record the H_2S content of the natural gas monthly by obtaining and keeping a current certified letter, valid purchase contract, tariff sheet, or transportation contract from the supplier stipulating that the natural gas supplied during the month does not contain more than 20 ppmv H_2S.

b. Report in the operating report under Condition 21 the monthly H_2S content of the natural gas. Report under Condition 20 if the H_2S content of the natural gas exceeds 20 ppmv.

15.2 The sulfur content of the diesel fuel burned in EU IDs 1 through 10, 13, and 14 when burning diesel and in EU IDs 11, 12, and 18 shall not exceed 15 parts per million by weight (ppmw) of sulfur.

a. Monitor and record monthly the sulfur content of the diesel fuel burned by obtaining and keeping a current certified letter or fuel receipts from the diesel fuel supplier that the diesel fuel supplied during the month was ULSD.

b. Report in the operating report under Condition 21 the type of diesel fuel received for each shipment. Report under Condition 20 if the fuel received was not ULSD.

Section 8. General Recordkeeping, Reporting, and Certification Requirements

16. Certification. The Permittee shall certify all reports, or other documents submitted to the Department and required under the permit by including the signature of a responsible official for the permitted stationary source following the statement: “Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.” Excess emissions reports must be certified either upon submittal or with an operating report required for the same reporting period. All other reports and other documents must be certified upon submittal.

17. Submittals. Unless otherwise directed by the Department or this permit, the Permittee shall send an original and one copy of reports, compliance certifications, and other submittals required by this permit to ADEC, Air Permits Program, 610 University Ave., Fairbanks, AK 99709-3643, ATTN: Compliance Technician. The Permittee may upon consultation with the Compliance Technician regarding software compatibility, provide electronic copies of data reports, emission source test reports, or other records under a cover letter certified in accordance with Condition 16.

18. Information Requests. The Permittee shall furnish to the Department, within a reasonable time, any information the Department requests in writing to determine whether cause exists to modify, revoke, reissue, or terminate the permit or to determine compliance with the permit. Upon request, the Permittee shall furnish to the Department copies of records required to be kept by the permit. The Department may require the Permittee to furnish copies of those records directly to the federal administrator.

19. Recordkeeping Requirements. The Permittee shall keep all records required by this permit for at least five years after the date of collection, including:

19.1 copies of all reports and certifications submitted pursuant to this section of the permit; and

19.2 records of all monitoring required by this permit, and information about the monitoring including (if applicable):

a. calibration and maintenance records, original strip chart or computer-based recordings for continuous monitoring instrumentation;

b. sampling dates and times of sampling or measurements;

c. the operating conditions that existed at the time of sampling or measurement;

d. the date analyses were performed;

e. the location where samples were taken;

f. the company or entity that performed the sampling and analyses;

g. the analytical techniques or methods used in the analyses; and

h. the results of the analyses.

20. Excess Emissions and Permit Deviation Reports.

20.1 Except as provided in Condition 22, the Permittee shall report all emissions or operations that exceed or deviate from the requirements of this permit as follows:

a. in accordance with 18 AAC 50.240(c), as soon as possible after the event commenced or is discovered, report

(i) emissions that present a potential threat to human health or safety; and

(ii) excess emissions that the Permittee believes to be unavoidable;

b. in accordance with 18 AAC 50.235(a), within two working days after the event commenced or was discovered, report an unavoidable emergency, malfunction, or nonroutine repair that caused emissions in excess of a technology based emissions standard;

c. report all other excess emissions and permit deviations

(i) within 30 days of the end of the month in which emissions or deviation occurs or is discovered, except as provided in Conditions 20.1c(ii) and 20.1c(iii);

(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 20.1c(i); and

(iii) for failure to monitor, as required in other applicable conditions of this permit.

20.2 The Permittee must report using either the Department's on-line form, or if the Permittee prefers, the form contained in Attachment 2. The Permittee must provide all information called for by the form that is used.

20.3 If requested by the Department, the Permittee shall provide a more detailed written report as requested to follow up an excess emissions report.

21. Operating Reports. During the life of this permit, the Permittee shall submit to the Department an original and one copy of an operating report by August 1st for the period January 1st through June 30th of the current year and by February 1st for the period July 1st through December 31st of the previous year.

21.1 The operating report must include all information required to be in operating reports by other conditions of this permit

21.2 If excess emissions or permit deviations that occurred during the reporting period are not reported under Condition 21.1, either

a. The Permittee shall identify

(i) the date of the deviation;

(ii) the equipment involved;

(iii)the permit condition affected;

(iv)any corrective action or preventative measures taken and the date of such actions; or;

b. when excess emissions or permit deviations have already been reported under Condition 20 the Permittee may cite the date or dates of those reports.

22. Air Pollution Prohibited. No person may permit any emissions 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.

22.1 If emissions present a potential threat to health or safety, the Permittee shall report any such emissions according to Condition 20.

22.2 As soon as practicable after becoming aware of a complaint that is attributable to emissions from the stationary source, the Permittee shall investigate the complaint to identify emissions that the Permittee believes have caused or are causing a violation of Condition 22.

22.3 The Permittee shall initiate and complete corrective action necessary to eliminate any violation identified by a complaint or investigation as soon as practicable if

a. after investigation because of complaint or other reason, the Permittee believes that emissions from the stationary source have caused or are causing a violation of Condition 22; or

b. the Department notifies the Permittee that it has found a violation of Condition 22.

22.4 The Permittee shall keep records of

a. the date and time, and nature of all emissions complaints received;

b. the name of the person or persons that complained, if known;

c. a summary of any investigation, including reasons the Permittee does or does not believe the emissions have caused a violation of Condition 22; and

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

22.5 With each operating report under Condition 21, 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.

22.6 The Permittee shall notify the Department of a complaint that is attributable to emissions from the stationary source within 24 hours after receiving the complaint, unless the Permittee has initiated corrective action within 24 hours of receiving the complaint.

Section 9. General Source Test Requirements

23. Requested Source Tests. In addition to any source testing explicitly required by this permit, the Permittee shall conduct source testing as requested by the Department to determine compliance with applicable permit requirements.

24. Operating Conditions. Unless otherwise specified by an applicable requirement or test method, the Permittee shall conduct source testing

24.1 at a point or points that characterize the actual discharge into the ambient air; and

24.2 at the maximum rated burning or operating capacity of the source or another rate determined by the Department to characterize the actual discharge into the ambient air

25. Reference Test Methods. The Permittee shall use the following references for test methods when conducting source testing for compliance with this permit:

25.1 Source testing for the reduction in visibility through the exhaust effluent must be conducted in accordance with the procedures set out in 40 C.F.R. 60, Appendix A, Reference Method 9. The Permittee may use the form in Attachment 1 of this permit to record data.

25.2 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.

25.3 Source testing for emissions of PM-10 must be conducted in accordance with the procedures specified in 40 C.F.R. 51, Appendix M, Methods 201 or 201A and 202. For EUs with stack temperatures exceeding 500 degrees Fahrenheit, source testing may be conducted in accordance with the procedures specified in 40 C.F.R. 60, Appendix A, Method 5 and 40 C.F.R. 51, Appendix M, Method 202.

25.4 Source testing for emissions of any contaminant may be determined using an alternative method approved by the Department in accordance with 40 C.F.R. 63 Appendix A, Method 301.

26. 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.

27. **Test Plans.** Before conducting any source tests, the Permittee shall submit a plan to the Department. The plan must include the methods and procedures to be used for sampling, testing, and quality assurance, and must specify how the emissions unit will operate during the test and how the Permittee will document that operation. The Permittee shall submit a complete test plan 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.

28. **Test Notification.** At least 10 days before conducting a source test, the Permittee shall give the Department written notice of the date and time the source test will begin.

29. **Test Reports.** Within 60 days after completing a source test, the Permittee shall submit two copies 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 as set out in Condition 16. If requested in writing by the Department, the Permittee must provide preliminary results in a shorter period of time specified by the Department.

Section 10. Standard Terms and Conditions

30. 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

30.1 an enforcement action; or

30.2 permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280.

31. 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.

32. 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.

33. 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.

34. The permit does not convey any property rights of any sort, nor any exclusive privilege.

Section 11. Permit Documentation

July 23, 2015	Matanuska Electric Association (MEA) submits a minor permit application to revise Minor Permit AQ1086MSS02
October 15, 2015	MEA submits comments on preliminary permit

Attachment 1. Visible Emissions Form

VISIBLE EMISSION OBSERVATION FORM

This form is designed to be used in conjunction with EPA Method 9, "Visual Determination of the Opacity of Emissions form Stationary Sources." Temporal changes in emission color, plume water droplet content, background color, sky conditions, observer position, etc. should be noted in the comments section adjacent to each minute of readings. Any information not dealt with elsewhere on the form should be noted under additional information. Following are brief descriptions of the type of information that needs to be entered on the form: for a more detailed discussion of each part of the form, refer to "Instructions for Use of Visible Emission Observation Form."

- Source Name: full company name, parent company or division or subsidiary information, if necessary.
- Address: street (not mailing or home office) address of facility where VE observation is being made.
- Phone (Key Contact): number for appropriate contact.
- Source ID Number: number from NEDS, agency file, etc.
- Process Equipment, Operating Mode: brief description of process equipment (include type of facility) and operating rate, % capacity, and/or mode (e.g. charging, tapping, shutdown).
- Control Equipment, Operating Mode: specify type of control device(s) and % utilization, control efficiency.
- Describe Emission Point: for identification purposes, stack or emission point appearance, location, and geometry; and whether emissions are confined (have a specifically designed outlet) or unconfined (fugitive).
- Height Above Ground Level: stack or emission point height relative to ground level; can use engineering drawings, Abney level, or clineometer.
- Height Relative to Observer: indicate height of emission point relative to the observation point.
- Distance from Observer: distance to emission point; can use rangefinder or map.
- Direction from Observer: direction plume is traveling from observer.
- Describe Emissions and Color: include physical characteristics, plume behavior (e.g., looping, lacy, condensing, fumigating, secondary particle formation, distance plume visible, etc.), and color of emissions (gray, brown, white, red, black, etc.). Note color changes in comments section.
- Visible Water Vapor Present?: check "yes" if visible water vapor is present.
- If Present, is Plume…: check "attached" if water droplet plume forms prior to exiting stack, and "detached" if water droplet plume forms after exiting stack.
- Point in Plume at Which Opacity was Determined: describe physical location in plume where readings were made (e.g., 1 ft above stack exit or 10 ft. after dissipation of water plume).
- Describe Plume Background: object plume is read against, include texture and atmospheric conditions (e.g., hazy).
- Background Color: sky blue, gray-white, new leaf green, etc.
- Sky Conditions: indicate cloud cover by percentage or by description (clear, scattered, broken, overcast).
- Wind Speed: record wind speed; can use Beaufort wind scale or hand-held anemometer to estimate.
- Wind Direction From: direction from which wind is blowing; can use compass to estimate to eight points.
- Ambient Temperature: in degrees Fahrenheit or Celsius.

  Wet Bulb Temperature: can be measured using a sling psychrometer

  RH Percent: relative humidity measured using a sling psychrometer; use local US Weather Bureau measurements only if nearby.
- Source Layout Sketch: include wind direction, sun position, associated stacks, roads, and other landmarks to fully identify location of emission point and observer position.

  Draw North Arrow: to determine, point line of sight in direction of emission point, place compass beside circle, and draw in arrow parallel to compass needle.

  Sun's Location: point line of sight in direction of emission point, move pen upright along sun location line, mark location of sun when pen's shadow crosses the observer's position.
- Observation Date: date observations conducted.
- Start Time, End Time: beginning and end times of observation period (e.g., 1635 or 4:35 p.m.).
- Data Set: percent opacity to nearest 5%; enter from left to right starting in left column. Use a second (third, etc.) form, if readings continue beyond 30 minutes. Use dash (-) for readings not made; explain in adjacent comments section.

  Comments: note changing observation conditions, plume characteristics, and/or reasons for missed readings.

  Range of Opacity: note highest and lowest opacity number.
- Observer's Name: print in full.

  Observer's Signature, Date: sign and date after performing VE observation.
- Organization: observer's employer.

Certified By, Date: name of "smoke school" certifying observer and date of most recent certification.

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY DIVISION - VISIBLE EMISSIONS OBSERVATION FORM

Page No.__________

Source Name | Type of Source

Address

City | State | Zip

Phone # (Key Contact) | Source ID Number

Process Equipment | Operating Mode

Control Equipment | Operating Mode

Describe Emission Point

Height above ground level | Height relative to observer | Inclinometer Reading

Distance From Observer | Direction From Observer Start End

Describe Emissions & Color
Start | End

Visible Water Vapor Present? If yes, determine approximate distance from the
No Yes stack exit to where the plume was read

Point in Plume at Which Opacity Was Determined

Describe Plume Background | Background Color
Start | Start
End | End

Sky Conditions: Start
End

Wind Speed | Wind Direction From Start End

Ambient Temperature | Wet Bulb Temp | RH percent

NOTES: 1 Stack or Point Being Read 2 Wind Direction From
3 Observer Location 4 Sun Location 5 North Arrow 6 Other Stacks

Observation Date | Start Time | End Time

Sec / Min	0	15	30	45	Comments
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					

Range of Opacity
Minimum | Maximum

I have received a copy of these opacity observations | Print Observer's Name

Print Name: | Observer's Signature | Date

Signature:

Title | Date | Organization

Certified By: | Date

Attachment 2. ADEC Notification Form

Eklutna Generation Station **No. AQ1086MSS03**

Stationary Source Name **Air Quality Permit No.**

Matanuska Electric Association ______

Company Name **Date**

When did you discover the Excess Emissions/Permit Deviation?

Date: ______ / ______ / _________ Time: ______ :/ ______

When did the event/deviation occur?

Begin Date: _____ / _____ / ________ Time: ______ : _______ (Use 24-hr clock.)

End Date _____ / _____ / ________ Time: ______ : _______ (Use 24-hr clock.)

What was the duration of the event/deviation? ____ : ____ (hrs:min) or ________ days

(total # of hrs, min, or days, if intermittent then include only the duration of the actual emissions/deviation)

Reason for Notification: (please check only 1 box and go to the corresponding section)

☐ Excess Emissions – Complete Section 1 and Certify

☐ Deviation from Permit Condition – Complete Section 2 and Certify

☐ Deviations from COBC, CO, or Settlement Agreement – Complete Section 2 and Certify

Section 1. Excess Emissions

(a) Was the exceedance: ☐ Intermittent or ☐ Continuous

(b) Cause of Event (Check one that applies):

☐ Start Up/Shut Down ☐ Natural Cause (weather/earthquake/flood)

☐ Control Equipment Failure ☐ Schedule Maintenance/Equipment Adjustment

☐ 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.

(d) Emissions Units Involved:
Identify the emission unit involved in the event, using the same identification number and name as in the permit. Identify each emission standard potentially exceeded during the event and the exceedance.

EU ID	EU Name	Permit Condition Exceeded/Limit/Potential Exceedance

(e) Type of Incident (please check only one):

☐ Opacity ______ % ☐ Venting ________ gas/scf ☐ Control Equipment Down

☐ Fugitive Emissions ☐ Emission Limit Exceeded ☐ Other ____________

☐ Marine Vessel Opacity ☐ Flaring ____________________

(f) Unavoidable Emissions:

Do you intend to assert that these excess emissions were unavoidable? ☐ Yes ☐ No

Do you intend to assert the affirmative defense of 18 AAC 50.235? ☐ Yes ☐ No

Certify Report (Go to end of form.)

Section 2. Permit Deviations

(a) Permit Deviation Type (check only one box, corresponding with the section in the permit):

☐ Emission Unit-Specific ☐ Generally Applicable Requirements

☐ Failure to Monitor/Report ☐ Reporting/Monitoring for Diesel Engines

☐ General Source Test/Monitoring Requirements ☐ Recordkeeping Failure

☐ Recording/Reporting/Compliance Certification ☐ Insignificant Emission Unit

☐ Standard Conditions Not Included in the Permit ☐ Stationary Source Wide

☐ Other Section: ______________________________ (Title of section and section number of your permit).

(b) Emission Unit Involved:

Identify the emission unit involved in the event, using the same identification number and name as in the permit. List the corresponding permit conditions 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.

(d) Corrective Actions:
Describe actions taken to correct the deviation or potential deviation and to prevent future recurrence.

Certification:

Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.

Printed Name: ____________________ Title: ____________________ Date: __________

Signature: ______________________ Phone Number: ________________________

NOTE: *This document must be certified in accordance with 18 AAC 50.345(j)*

To Submit this Report:

Fax to: 907-451-2187

Or

Email to: DEC.AQ.Airreports@alaska.gov

If faxed or emailed, the report must be certified within the operating report required for the same reporting period per Condition 21.

Or

Mail to: ADEC
Air Permits Program
610 University Avenue
Fairbanks, AK 99709-3643

Or

Phone Notification: 907-451-5173

Phone notifications require a written follow-up report.

Or

Submission of information contained in this report can be made electronically at the following website:

https://myalaska.state.ak.us/dec/air/airtoolsweb/

If submitted online, report must be submitted by an authorized E-Signer for the stationary source.

DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY OPERATING PERMIT

Permit No. AQ1086TVP02 Issue Date: February 2, 2022
Expiration Date: February 2, 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, **Matanuska Electric Association, Inc.**, for the operation of the **Eklutna Generation Station**.

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 currently applicable stationary source-specific terms and conditions of Air Quality Minor Permit AQ1086MSS03 have been incorporated into this operating permit.

This Operating Permit becomes effective March 4, 2022.

for:

James R. Plosay, Manager
Air Permits Program

Table of Contents

Abbreviations and Acronyms

AAC....................Alaska Administrative Code
ADEC ....Alaska Department of Environmental Conservation
AOS ....Air Online Services
AS ....Alaska Statutes
ASTM ....American Society for Testing and Materials
BACT ....best available control technology
bhp ....brake horsepower
CATOX ....catalytic oxidation
CAA or The Act .Clean Air Act
CDX....................central data exchange
CEDRI ....compliance and emissions data reporting interface
CFR ....Code of Federal Regulations
CH_2O ....formaldehyde
CO ....carbon monoxide
Department ....Alaska Department of Environmental Conservation
dscf ....dry standard cubic foot
EPA ....US Environmental Protection Agency
EU ID ....emissions unit identification number
gr./dscf................grain per dry standard cubic foot (1 pound = 7000 grains)
HAP ....hazardous air pollutants [as defined in AS 46.14.990]
hp ....horsepower
H_2S......................hydrogen sulfide
kPa ....kilopascals
kW ....kilowatt
LAER..................lowest achievable emission rate
MACT ....maximum achievable control technology [as defined in 40 CFR 63]
MMBtu/hr...........million British thermal units per hour
MMscf ....million standard cubic feet
MR&R ....monitoring, recordkeeping, and reporting
MW ....Megawatt
NESHAP ....National Emission Standards for Hazardous Air Pollutants [as contained in 40 CFR 61 and 63]
NFPA ....National Fire Protection Association
NG........................natural gas
NO_X......................nitrogen oxides
NO_2.......................nitrogen dioxide
NSPS ....New Source Performance Standards [as contained in 40 CFR 60]
O & M ....operation and maintenance
O_2 ....oxygen
ORL......................owner requested limit
PAL ....Plant wide Applicability Limitation
PM_{10} ....particulate matter less than or equal to a nominal ten 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
SCR ....selective catalytic reduction
SIC. ....Standard Industrial Classification
SO_2 ....sulfur dioxide
tpy ....tons per year
ULSD ....ultra-low sulfur diesel
VOC ....volatile organic compound [as defined in 40 CFR 51.100(s)]
VOL ....volatile organic liquid [as defined in 40 CFR 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:		**Matanuska Electric Association, Inc.** P.O. Box 2929 Palmer, AK 99645
Stationary Source Name:		**Eklutna Generation Station**
Location:		61º 27´ 34.5” North; 149º 20´ 33.9” West
Physical Address:		28705 Dena’ina Elders Road Chugiak, AK 99567
Owner/Operator:		**Matanuska Electric Association, Inc.** P.O. Box 2929 Palmer, AK 99645
Permittee’s Responsible Official and Designated Agent:		Joshua Crowell, Eklutna Generation Station Plant Manager P.O. Box 2929 Palmer, AK 99645
Stationary Source and Building Contact:		Traci Bradford, Environmental Engineer P.O. Box 2929 Palmer, AK 99645 907-761-9374 traci.bradford@mea.coop
Fee Contact:		Traci Bradford, Environmental Engineer P.O. Box 2929 Palmer, AK 99645 907-761-9374
Permit Contact:		Traci Bradford, Environmental Engineer P.O. Box 2929 Palmer, AK 99645 907-761-9374 traci.bradford@mea.coop
Process Description	SIC Code:	4911 – Electric services
	NAICS Code:	221112 – Fossil fuel electric power generation

[18 AAC 50.040(j)(3) & 50.326(a)]
[40 CFR 71.5(c)(1) & (2)]

Section 2. Emissions Unit Inventory and Description

Emissions units (EUs) 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.

Table A - Emissions Unit Inventory

EU ID	Emissions Unit Name	Emissions Unit Description	Rating/Size	Fuel	Construction Date
1	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
2	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
3	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
4	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
5	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
6	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
7	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
8	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
9	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
10	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
11	Fire Pump Engine	John Deere JU6H-UFADN0	197 hp	ULSD	June 2012
12	Black Start Generator Engine	Cummins 1000DQFAD	1,490 hp	ULSD	June 2013
13	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	15.75 MMBtu/hr	Natural Gas /ULSD	June 2013
14	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	15.75 MMBtu/hr	Natural Gas /ULSD	June 2013
17	NG Fuel Heater	Aether C5-G30	8.3 MMBtu/hr	Natural Gas	September 2016
18	Black Start Generator Engine	Cummins 1000DQFAD	1,490 hp	ULSD	June 2013

Note:

EU IDs 15 and 16 are diesel storage tanks and insignificant under 18 AAC 50.326(e).

[18 AAC 50.326(a)]
[40 CFR 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 1 through 14, 17, and 18 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 CFR 71.6(a)(1)]

1.1. For EU ID 11, as long as the emissions unit does not exceed the limit in Condition 14, monitoring shall consist of an annual compliance certification under Condition 64 for the visible emission standard based on reasonable inquiry. Otherwise, monitor, record and report in accordance with Conditions 2 through 4 for the remainder of the permit term.

1.2. For each of EU IDs 12 and 18, as long as the emissions unit does not operate more than 233 hours[1] during any consecutive 12-month period, monitoring shall consist of an annual compliance certification under Condition 64 with the visible emission standard based on reasonable inquiry. The Permittee shall report in the operating report under Condition 63 if EU ID 12 or EU ID 18 operates more than 233 hours during any consecutive 12-month period 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 IDs 1 through 10, 13, and 14, burn natural gas as the primary fuel. Monitoring for these emissions units shall consist of a statement in each operating report required under Condition 63 indicating whether each of these emissions units burned natural gas as the primary fuel during the period covered by the report. If any of these units operated exclusively on ULSD during the period covered by the report, the Permittee shall monitor, record, and report in accordance with Condition 9 for that emissions unit.

1.4. For EU ID 17, burn only natural gas as fuel. In each operating report under Condition 63, indicate whether the emissions unit burned only natural gas during the period covered by the report. Report under Condition 62 if any fuel other than natural gas is burned.

[18 AAC 50.040(j)(4), 50.326(j)(3), & 50.346(c)]
[40 CFR 71.6(a)(3)]

[1] Annual operation of 234 hours is equivalent to the worst-case significant emissions threshold in 18 AAC 50.326(e) for EU IDs 12 and 18.

Visible Emissions Monitoring, Recordkeeping and Reporting (MR&R)

Liquid Fuel-Burning Equipment

2. Visible Emissions Monitoring. When required by Condition 1.1 or 1.2, or in the event of replacement[2] during the permit term, the Permittee shall observe the exhaust of EU IDs 11, 12, and 18 for visible emissions using either the Method 9 Plan under Condition 2.3 or the Smoke/No-Smoke Plan under Condition 2.4.

2.1. The Permittee may change the visible emissions monitoring plan for an emissions unit at any time unless prohibited from doing so by Condition 2.5.

2.2. The Permittee may, for each unit, elect to continue the visible emissions monitoring schedule specified in Conditions 2.3.b through 2.3.e or Conditions 2.4.b through 2.5 that remains in effect from a previous permit.

2.3. **Method 9 Plan.** For all observations in this plan, observe emissions unit exhaust, following 40 CFR 60, Appendix A-4, Method 9 for 18 minutes to obtain 72 consecutive 15-second opacity observations.[3]

a. First Method 9 Observation. Except as provided in Condition 2.2 or Condition 2.5.c(ii), observe the exhausts of EU IDs 11, 12 and 18 according to the following criteria:

(i) For any unit, observe emissions unit exhaust within 14 calendar days after changing from the Smoke/No-Smoke Plan of Condition 2.4

(ii) For any unit replaced, observe exhaust within 60 days of the newly installed emissions unit becoming fully operational.[4] Except as provided in Condition 2.3.e, after the First Method 9 observation:

(A) For EU IDs 11, 12, and 18, comply with Conditions 1.1 and 1.2, as applicable.

(iii) For each of EU IDs 11, 12, and 18, observe the exhaust of the emissions unit within 30 days after the end of the calendar month during which monitoring was triggered under Condition 1.1 or 1.2; or for an emissions unit with intermittent operations, within the first 30 days during the units next scheduled operation.

b. Monthly Method 9 Observations. After the first Method 9 observation conducted under Condition 2.3.a, perform observations at least once in each calendar month that the emissions unit operates.

[2] "*Replacement*," as defined in 40 CFR 51.166(b)(32).
[3] Visible emissions observations are not required during emergency operations
[4] *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.

c. Semiannual Method 9 Observations. After at least three monthly observations under Condition 2.3.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.

d. Annual Method 9 Observations. After at least two semiannual observations under Condition 2.3.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 2.3.b, and continue monitoring in accordance with the Method 9 Plan.

2.4. **Smoke/No Smoke Plan.** Observe the emissions unit exhaust for the presence or absence of visible emissions, excluding condensed water vapor.

a. Initial Monitoring Frequency. Observe the emissions unit exhaust during each calendar day that the emissions unit operates for a minimum of 30 days.

b. Reduced Monitoring Frequency. If the emissions unit operates without visible emissions for 30 consecutive operating days as required in Condition 2.4.a, observe the emissions unit exhaust at least once in every calendar month that the emissions unit operates.

c. Smoke Observed. If visible emissions are observed, comply with Condition 2.5.

2.5. **Corrective Actions Based on Smoke/No Smoke Observations**. If visible emissions are present in the emissions unit exhaust during an observation performed under the Smoke/No Smoke Plan of Condition 2.4, then the Permittee shall either begin the Method 9 plan of Condition 2.3, or

a. initiate actions to eliminate visible emissions from the emissions unit exhaust within 24 hours of the observation;

b. keep a written record of the starting date, the completion date, and a description of the actions taken to reduce visible emissions; and

c. after completing the actions required under Condition 2.5.a,

(i) conduct smoke/no smoke observations in accordance with Condition 2.4.

(A) at least once per day for the next seven operating days and, if applicable, until the initial 30-day observation period of Condition 2.4.a is completed; and

(B) continue as described in Condition 2.4.b; or

(ii) if the actions taken under Condition 2.5.a do not eliminate the visible emissions, or if subsequent visible emissions are observed under the schedule of Condition 2.5.c(i)(A), then observe the emissions unit exhaust using the Method 9 Plan unless the Department gives written approval to resume observations under the Smoke/No Smoke Plan. After observing visible emissions and making observations under the Method 9 Plan, the Permittee may at any time, take corrective action that eliminates visible emissions and restart the Smoke/No Smoke Plan under Condition 2.4.a.

[18 AAC 50.040(j)(4), 50.326(j)(3), & 50.346(c)]
[40 CFR 71.6(a)(3)(i)]

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

3.1. For all Method 9 Plan 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 Emission Observation Form in Section 11;

(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 11, 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-consecutive-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;

(iv) record the average opacity on the sheet.

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

3.2. If using the Smoke/No Smoke Plan of Condition 2.4, record the following information in a written log for each observation and submit copies of the recorded information upon request of the Department:

a. the date and time of the observation;

b. the EU ID of the emissions unit observed;

c. whether visible emissions are present or absent in the emissions unit exhaust;

d. a description of the background to the exhaust during the observation;

e. if the emissions unit starts operation on the day of the observation, the startup time of the emissions unit;

f. name and title of the person making the observation; and

g. operating rate (load or fuel consumption rate or best estimate, if unknown).

3.3. The records required by Conditions 3.1 and 3.2 may be kept in electronic format.

[18 AAC 50.040(j)(4), 50.326(j)(3), & 50.346(c)]
[40 CFR 71.6(a)(3)(ii)]

4. Visible Emissions Reporting. The Permittee shall report as follows:

4.1. In the first operating report required in Condition 63 under this permit term, the Permittee shall state the intention to either continue the visible emissions monitoring schedule in effect from the previous permit or rest the visible emissions monitoring schedule.

4.2. Include in each operating report required under Condition 63 for the period covered by the report:

a. which visible-emissions plan of Condition 2 was used for each emissions unit; if more than one plan was used, give the time periods covered by each plan;

b. 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;

c. for each emissions unit under the Smoke/No Smoke Plan, the number of days that smoke/no smoke observations were made and which days, if any, that visible emissions were observed; and

d. a summary of any monitoring or recordkeeping required under Conditions 2 and 3 that was not done.

4.3. Report under Condition 62:

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 CFR 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 PM emitted from EU IDs 1 through 14, 17, and 18 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 CFR 71.6(a)(1)]

5.1. For EU ID 11, as long as the emissions unit does not exceed the limit in Condition 14, monitoring shall consist of an annual compliance certification under Condition 64 for the PM emissions standard based on reasonable inquiry. Otherwise, monitor, record and report in accordance with Conditions 6 through 8 for the remainder of the permit term.

5.2. For each of EU IDs 12 and 18, as long as the emissions unit does not operate more than 233 hours during any consecutive 12-month period, monitoring shall consist of an annual compliance certification under Condition 64 with the PM emission standard based on reasonable inquiry. The Permittee shall report in the operating report under Condition 63 if EU ID 12 or EU ID 18 operates more than 233 hours during any consecutive 12-month period 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 IDs 1 through 10, 13, and 14, the Permittee shall comply with Condition 1.3.

5.4. For EU ID 17, the Permittee shall comply with Condition 1.4.

[18 AAC 50.040(j)(4), 50.326(j)(3), & 50.346(c)]
[40 CFR 71.6(a)(3)]

Particulate Matter MR&R

Liquid Fuel-Burning Engines

6. Particulate Matter Monitoring. The Permittee shall conduct source tests on EU IDs 11, 12 and 18 to determine the concentration of PM in the exhaust of each of the emissions units as follows:

6.1. If the result of any Method 9 observation conducted under Condition 2.3 for any of EU IDs 11, 12, and 18 is greater than the criteria of Conditions 6.2.a or 6.2.b, or if the Method 9 observation conducted under Condition 9.3 for EU IDs 1 through 10 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 CFR 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 under 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 2.3 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 requirement in Condition 6.1.b are waived for an emissions unit if:

a. a 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 2.3) conducted thereafter within a six-month period show visible emissions less than the threshold in Condition 6.2.

[18 AAC 50.040(j)(4), 50.326(j)(3), & 50.346(c)]
[40 CFR 71.6(a)(3)(i)]

7. Particulate Matter Recordkeeping. The Permittee shall 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 CFR 71.6(a)(3)(ii)]

8. Particulate Matter 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 6.2.b within 30 days of the end of the month in which the observations occurred. Include the dates, EU ID(s), 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 63, 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 62:

a. anytime the results of a 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 CFR 71.6(a)(3)(iii)]

Visible Emissions & Particulate Matter MR&R

Dual Fuel-Burning Equipment

9. The Permittee shall monitor, record, and report the monthly hours of operation of EU IDs 1 through 10, 13, and 14 when operating exclusively on ULSD.

9.1. For any of EU IDs 1 through 10, 13, and 14 that does not exceed 400 hours of operation per calendar year on ULSD exclusively, monitoring of compliance for visible emissions and PM shall consist of an annual compliance certification under Condition 64 based on reasonable inquiry.

9.2. For any of EU IDs 1 through 10, 13, and 14, notify the Department and begin monitoring the affected emissions unit in accordance with Condition 9.3 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 ULSD exclusively; or for an emissions unit with intermittent ULSD use, during the next scheduled operation on ULSD exclusively.

9.3. When required to do so by Condition 9.2, observe the emissions unit exhaust, following 40 CFR 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 EU IDs 1 through 10 as described in Condition 6 and monitor, record, and report for EU IDs 13 and 14 as follows:

(i) 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 CFR 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) conduct a PM source test according to the requirements in Section 6. The PM source test is waived for an emissions unit if a source test on that unit has shown compliance with the PM standard during this permit term or if corrective action was taken to reduce visible emissions and two consecutive 18-minute Method 9 observations conducted thereafter within a six-month period show visible emissions less than 20 percent average opacity.

(ii) During each one-hour PM source test run under Condition 9.3.a(i)(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.

(iii) Keep records of the results of any source test and visible emissions observations conducted under Conditions 9.3.a(i) and 9.3.a(ii).

(iv) Notify the Department of any Method 9 observation that results in an 18-minute average opacity greater than 20 percent within 30 days of the end of the month in which the observations occurred. Include the dates, EU ID(s), and results when an observed 18-minute average opacity was greater than 20 percent.

(v) In each operating report required by Condition 63, include:

(A) a summary of the results of any source test and visible emissions observations conducted under Conditions 9.3.a(i) and 9.3.a(ii).

(B) copies of any visible emissions observation results greater than the threshold in Condition 9.3.a(iv), if they were not already submitted.

(vi) Report in accordance with Condition 62 any time the results of a source test exceed the PM emission standard in Condition 5.

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 ULSD exclusively, during a calendar year.[5]

9.4. Keep records and report in accordance with Conditions 3, 4, 7, 8, and 9.3.a(iii) through 9.3.a(vi), as applicable.

9.5. Report under Condition 62 if the Permittee fails to comply with any of Conditions 9.2 through 9.4.

[18 AAC 50.040(j)(4), 50.326(j)(3) & (4), & 50.346(c)]
[40 CFR 71.6(a)(3) & 71.6(c)(6)]

Sulfur Compound Emissions Standard

10. Sulfur Compound Emissions. The Permittee shall not cause or allow sulfur compound emissions, expressed as SO_2, from EU IDs 1 through 14, 17, and 18 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 CFR 71.6(a)(1)]

Sulfur Compound MR&R

11. Sulfur Compound Emissions MR&R. To ensure compliance with Condition 10, the Permittee shall comply as follows:

[5] 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.

Fuel Oil[6]

11.1. **Liquid Fuel-Burning Equipment**. For EU IDs 1 through 14 and 18, comply with the fuel sulfur content limit and associated MR&R requirements in Condition 12.2.

Fuel Gas

11.2. **Natural Gas-Burning Equipment**. For EU IDs 1 through 10, 13, 14 and 17, comply with the fuel sulfur content limit and associated MR&R requirements in Condition 12.1.

[18 AAC 50.040(j)(4), & 50.326(j)(3)]
[40 CFR 71.6(a)(3) & (c)(6)]

Preconstruction Permit[7] Requirements

Limits to Avoid Minor Permitting under 18 AAC 50.502(c)(1)(C)

12. Fuel Sulfur Requirements. The Permittee shall monitor the sulfur content of the ULSD and hydrogen sulfide (H_2S) content of the natural gas burned as follows.

12.1. The H_2S content of the natural gas burned in EU IDs 1 through 10, 13, 14, and 17 shall not exceed 20 parts per million by volume (ppmv).

a. Monitor and record the H_2S content of the natural gas monthly by obtaining and keeping a current certified letter, valid purchase contract, tariff sheet, or transportation contract from the supplier stipulating that the natural gas supplied during the month does not contain more than 20 ppmv H_2S.

b. Report in the operating report under Condition 63 the monthly H_2S content of the natural gas. Report under Condition 62 if the H_2S content of the natural gas exceeds 20 ppmv.

12.2. The sulfur content of the diesel fuel burned in EU IDs 1 through 10, 13, and 14 when burning diesel and in EU IDs 11, 12, and 18 shall not exceed 15 parts per million by weight (ppmw) of sulfur.

a. Monitor and record monthly the sulfur content of the diesel fuel burned by obtaining and keeping a current certified letter or fuel receipts from the diesel fuel supplier that the diesel fuel supplied during the month was ULSD.

b. Report in the operating report under Condition 63 the type of diesel fuel received for each shipment. Report under Condition 62 if the fuel received was not ULSD.

[Condition 15, Minor Permit AQ1086MSS03, 11/6/2015]
[18 AAC 50.040(j) & 50.326(j)(4)]
[40 CFR 71.6(a)(1) & (a)(3)]

6 *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 CFR 60.41b.

7 *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 after October 1, 2004.

Owner Requested Limits to Avoid Classification as PSD Major Source

13. Limits for EU IDs 1 through 10. The Permittee shall limit the combined hours of operation of EU IDs 1 through 10 to no more than 1,680 hours per 12-month rolling period when firing ultra-low sulfur diesel (ULSD) exclusively.

13.1. The Permittee shall burn only natural gas and ULSD in EU IDs 1 through 10.

13.2. Install and maintain a non-resettable hour meter on EU IDs 1 through 10.

13.3. Monitor and record the hours of operation each month for each of EU IDs 1 through 10 when firing ULSD exclusively.

13.4. By the end of each calendar month, calculate and record the combined hours of operation for EU IDs 1 through 10 during the previous month, then calculate the 12-month rolling combined hours for EU IDs 1 through 10 when firing ULSD exclusively.

13.5. Report in the operating report under Condition 63 the rolling 12-month combined hours of operation for EU IDs 1 through 10 when firing ULSD exclusively.

13.6. Notify the Department under Condition 62 if the consecutive 12-month combined hours of operation for EU IDs 1 through 10, when firing ULSD exclusively, exceed 1,680 hours.

[Condition 5, Minor Permit AQ1086MSS03, 11/6/2015]
[18 AAC 50.040(j) & 50.326(j)(4)]
[40 CFR 71.6(a)(1) & (a)(3)]

14. Limit for EU ID 11: The Permittee shall limit the operation of EU ID 11 to no more than 500 hours per year.

14.1. Install and maintain a non-resettable hour meter on EU ID 11.

14.2. Monitor and record the monthly hours of operation for EU ID 11.

14.3. By the end of each month, calculate and record the operating hours of EU ID 11 for the previous month.

14.4. Report in the operating report under Condition 63 the rolling 12-month hours of operation for EU ID 11.

14.5. Notify the Department under Condition 62 if the rolling 12-month hours of operation for EU ID 11 exceed 500 hours.

[Condition 6, Minor Permit AQ1086MSS03, 11/6/2015]
[18 AAC 50.040(j) & 50.326(j)(4)]
[40 CFR 71.6(a)(1) & (a)(3)]

15. Limits for EU IDs 13 and 14: The Permittee shall limit the combined hours of operation of EU IDs 13 and 14 to no more than 1,000 hours per rolling 12-month period when firing ULSD exclusively.

15.1. The Permittee shall fire only natural gas and ULSD in EU IDs 13 and 14.

15.2. Install and maintain a non-resettable hour meter on each of EU IDs 13 and 14.

15.3. Monitor and record the monthly operating hours for each of EU IDs 13 and 14 when firing ULSD exclusively.

15.4. By the end of each month, calculate and record the combined operating hours of EU IDs 13 and 14 during the previous month, then calculate the rolling 12-month combined hours for EU IDs 13 and 14 when firing ULSD exclusively.

15.5. Report in the operating report under Condition 63 the rolling 12-month combined operating hours for EU IDs 13 and 14 when firing ULSD exclusively.

15.6. Notify the Department under Condition 62 if the rolling 12-month combined hours of operation for EU IDs 13 and 14, when firing ULSD exclusively, exceed 1,000 hours.

[Condition 7, Minor Permit AQ1086MSS03, 11/6/2015]
[18 AAC 50.040(j) & 50.326(j)(4)]
[40 CFR 71.6(a)(1) & (a)(3)]

16. **Control Equipment:** The Permittee shall operate and maintain a combined selective catalytic reduction (SCR) and catalytic oxidation (CATOX) control equipment downstream of each of EU IDs 1 through 10 according to the manufacturer's instructions and as follows:

16.1. For the combined control equipment[8], while operating on natural gas, monitor and record hourly:

a. the rate of injection of the reducing aqueous ammonia reagent into the flue gas leaving the emissions unit. The 3-hour rolling average ammonia injection rate shall be no less than 1.0 gallons per hour (gal/hr) and no more than 38.5 gal/hr[9], except during startup and shutdown.

b. the temperature of the flue gas leaving the combined control equipment. The 3-hour rolling average temperature of the flue gas leaving the combined control equipment shall be no less than 536°F and no more than 997°F[10], except during startup and shutdown.

c. the pressure drop across the combined control equipment. The 3-hour rolling average pressure drop shall be no less than 1.5 inches of water and no more than 10 inches of water, except during startup and shutdown.

16.2. Keep on site the necessary manufacturer-recommended spare parts, reagents, catalysts, and operation manual for the control equipment.

16.3. In case of equipment malfunction, implement manufacturer-recommended corrective actions and record:

[8] SCR and CATOX with the CATOX downstream of the SCR.
[9] The minimum injection rate is from the permit application; maximum injection rate is from the manufacturer's specifications.
[10] The temperature rates are from the manufacturer specifications.

a. complete description of the corrective action; and

b. date(s) of the corrective action

16.4. Keep records of:

a. all control equipment system repairs;

b. hourly operating parameters established in Condition 16.1, dates and times each control equipment is started up or shut down;

c. system alarm logs including time and date of occurrence; and

d. receipts for all aqueous ammonia purchases (with dates and quantities).

16.5. Report under Condition 62 all:

a. control equipment malfunctions and associated corrective actions;

b. operating parameters that are outside the ranges in Condition 16.1; and

c. periods (starting and ending hour) during which a control equipment was not operating within the ranges established in Condition 16.1 while its associated generator was operating.

[Condition 8, Minor Permit AQ1086MSS03, 11/6/2015]
[18 AAC 50.040(j) & 50.326(j)(4)]
[40 CFR 71.6(a)(1) & (a)(3)]

Limit to Avoid Classification as HAP Major Source

17. Formaldehyde (CH_2O) Emission Limit: The Permittee shall limit CH_2O emissions from EU IDs 1 through 10 while firing natural gas to no more than 9.6 tons per year (tpy) during any consecutive 12 months by operating and maintaining the control equipment as described in Condition 16.

[Condition 9, Minor Permit AQ1086MSS03, 11/6/2015]
[18 AAC 50.040(j) & 50.326(j)(4)]
[40 CFR 71.6(a)(1)]

Ambient Air Quality Protection Requirements

18. Annual NO_2 Ambient Air Quality Protection: To protect the annual NO_2 ambient air quality standard, the Permittee shall:

18.1. For EU IDs 1 through 10, the Permittee shall maintain a release height for each stack that equals or exceeds 30.0 meters above grade.

[Condition 13, Minor Permit AQ1086MSS03, 11/6/2015]
[18 AAC 50.040(j) & 50.326(j)(4)]
[40 CFR 71.6(a)(1)]

19. Annual NO_2 and 24-hr PM_{10} Ambient Air Quality Protection: To protect the annual NO_2 and 24-hr PM_{10}, the combined operating hours for EU IDs 12 and 18 shall not exceed 1,000 hours per rolling 12-month period.

19.1. Install and maintain a non-resettable hour meter on each of EU IDs 12 and 18.

19.2. Monitor and record the hours of operation of each emissions unit and the combined hours of operation for EU IDs 12 and 18 for each month.

19.3. At the end of each month, calculate and record for the previous month, the combined hours of operation for EU ID 12 and EU ID 18 during the month, then calculate the combined 12-month rolling total hours of operation by adding the hours of operation for the previous 11 months.

19.4. Report in the operating report under Condition 63 the combined rolling 12-month hours of operation for EU IDs 12 and 18.

19.5. Notify the Department under Condition 62 should the combined consecutive 12-month operating hours for EU IDs 12 and 18 exceed 1,000 hours.

[Condition 14, Minor Permit AQ1086MSS03, 11/6/2015]
[18 AAC 50.040(j) & 50.326(j)(4)]
[40 CFR 71.6(a)(1) & (a)(3)]

Insignificant Emissions Units

20. 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:

20.1. **Visible Emissions Standard**. The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from an industrial process, 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)]

20.2. **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)]

20.3. **Sulfur 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)]

20.4. **General MR&R for Insignificant Emissions Units**

a. The Permittee shall submit the certification of compliance of Condition 64 based on reasonable inquiry;

b. The Permittee shall comply with the requirements of Condition 45;

c. The Permittee shall report in the operating report required under Condition 63 if an emissions unit is insignificant because of actual emissions less than the thresholds of 18 AAC 50.326(e) and actual emissions become greater than any of those thresholds; and

d. No other monitoring, recordkeeping or reporting is required for the insignificant emissions units to demonstrate compliance with the emissions standards under Conditions 20.1, 20.2, and 20.3.

[18 AAC 50.040(j)(4), 50.326(j)(3), & 50.346(b)(4)]
[40 CFR 71.6(a)(1) & (a)(3)]

Section 4. Federal Requirements

40 CFR Part 60 New Source Performance Standards (NSPS)

Subpart A – General Provisions

21. NSPS Subpart A Notification. Unless exempted by a specific subpart, for any affected facility[11] or existing facility[12] regulated under NSPS requirements in 40 CFR 60, the Permittee shall furnish the Administrator[13] written notification or, if acceptable to both the EPA and the Permittee, electronic notification as follows:

[18 AAC 50.035 & 50.040(a)(1)]
[40 CFR 60.7(a) & 60.15(d), Subpart A]

21.1. A notification of the date that construction (or reconstruction as defined under 40 CFR 60.15) of an affected facility is commenced 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 CFR 60.7(a)(1), Subpart A]

21.2. A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.

[40 CFR 60.7(a)(3), Subpart A]

21.3. A notification of 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 CFR 60.14(e). This notice shall be 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 CFR 60.7(a)(4), Subpart A]

21.4. A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with 40 CFR 60.13(c). Notification shall be postmarked not less than 30 days prior to such date.

[40 CFR 60.7(a)(5), Subpart A]

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

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

[13] The Department defines "Administrator" in 18 AAC 50.990(2).

21.5. A notification of the anticipated date for conducting the opacity observations required by 40 CFR 60.11(e)(1). The notifications shall also include, if appropriate, a request for the EPA to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date.

[40 CFR 60.7(a)(6), Subpart A]

21.6. If an owner or operator of an existing facility proposes to replace components, and 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, he shall notify the Administrator of the proposed replacements. The notice must be postmarked 60 days (or as soon as practicable) before construction of the replacement is commenced and must including the following information:

a. name and address of the owner or operator,

b. the location of the existing facility,

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

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

e. an estimate of the fixed capital cost of the replacements, and of constructing a comparable entirely new facility,

f. the estimated life of the existing facility after the replacements, and

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.

[40 CFR 60.15(d), Subpart A]

22. 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 ID(s) 1 through 14 and 18, any malfunction of the air-pollution control equipment, or any periods during which a continuous monitoring system or monitoring device for EU ID(s) 1 through 14 and 18 is inoperative.

[18 AAC 50.040(a)(1)]
[40 CFR 60.7(b), Subpart A]

23. NSPS Subpart A Performance (Source) Tests. The Permittee shall conduct source tests according to Section 6 and as required in this condition on any affected facility.

23.1. Except as specified in paragraphs (a)(1), (a)(2), (a)(3), and (a)(4) of 40 CFR 60.8, within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, or at such other times specified by 40 CFR Part 60, and at such other times as may be required by EPA, the owner or operator of such facility shall conduct performance test(s) and furnish EPA and the Department a written report of the results of such performance test(s).

[18 AAC 50.040(a)(1)]
[40 CFR 60.8(a), Subpart A]

24. 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 ID(s) 13 and 14 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 ID(s) 13 and 14.

[18 AAC 50.040(a)(1)]
[40 CFR 60.11(d), Subpart A]

25. 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 any standard in Condition 27, 28, or 29, nothing in 40 CFR Part 60 shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether EU IDs 1 through 14 and 18 would have been in compliance with applicable requirements of 40 CFR Part 60 if the appropriate performance or compliance test or procedure had been performed.

[18 AAC 50.040(a)(1)]
[40 CFR 60.11(g), Subpart A]

26. 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 Condition 27, 28, or 29. 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 CFR 60.12, Subpart A]

NSPS Subpart Dc – Steam Generating Units

NSPS Subpart Dc Applicability

27. For EU IDs 13 and 14, the Permittee shall comply with any applicable requirement in 40 CFR 60 Subpart Dc for small steam generating units for which construction is commenced after June 9, 1989 and that has a maximum design capacity of 100 MMBtu/hr or less but greater than or equal to 10 MMBtu/hr.

[18 AAC 50.040(a)(2)(D), (j)(4) & 50.326(j)]
[40 CFR 71.6(a)(1)]
[40 CFR 60.40c(a), Subpart Dc]

NSPS Subpart Dc Sulfur Dioxide Standard

27.1. At all times, including periods of startup, shutdown, and malfunction, when EU IDs 13 and 14 combust fuel oil, the Permittee shall **either**:

a. emit no more than 0.5 lb SO_2/MMBtu (215 ng/J) heat input from fuel oil combusted, **or**

b. combust fuel oil that contains no more than 0.5 percent sulfur by weight.

[18 AAC 50.040(a)(2)(D)]
[40 CFR 60.42c(d) & (i), Subpart Dc]

NSPS Subpart Dc MR&R Requirements

27.2. Compliance with the emission limits or fuel oil sulfur limits under Condition 27.1 shall be determined based on a certification from the fuel supplier and demonstrated by complying with Condition 12.2.

[40 CFR 60.42c(h)(1), 60.44c(h), & 60.46c(e), Subpart Dc]

27.3. The Permittee shall maintain records consistent with Condition 58 and shall submit reports to EPA as follows:

a. Include the calendar dates covered in the reporting period and a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

[40 CFR 60.48c(d), (e)(l) & (11), Subpart Dc]

b. Fuel supplier certification shall include the following information:

(i) The name of the oil supplier;

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in 40 CFR 60.41c; and

(iii) The sulfur content or maximum sulfur content of the oil.

[40 CFR 60.48c(f)(l), Subpart Dc]

c. The reporting period for the reports required under Condition 27.3 is each six-month period. All reports shall be submitted to the EPA and shall be postmarked by the 30th day following the end of the reporting period.

[40 CFR 60.48c(j), Subpart Dc]

27.4. Except as provided under Condition 27.5, for each of EU IDs 13 and 14, the Permittee shall record the amount of each fuel combusted during each operating day and maintain the records consistent with Condition 58.

27.5. As an alternative to meeting the requirements of Condition 27.4, the Permittee may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

[18 AAC 50.040(a)(2)(D)]
[40 CFR 60.48c(g)(1) & (2), Subpart Dc]

NSPS Subpart IIII [14]– Compression Ignition Internal Combustion Engines

NSPS Subpart IIII Applicability and Compliance Requirements

28. For EU IDs 11, 12, and 18, listed in Table A, the Permittee shall comply with the applicable requirements in 40 CFR 60 Subpart IIII for stationary compression ignition (CI) internal combustion engine (ICE) whose construction[15] commences after July 11, 2005 where the stationary CI ICE is manufactured after April 1, 2006 (emergency units, EU IDs 12 and 18) and manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006 (EU ID 11).

[18 AAC 50.040(a)(2)(OO), (j)(4) & 50.326(j)]
[40 CFR 71.6(a)(1)]
[40 CFR 60.4200(a)(2), Subpart IIII]

28.1. Comply with the applicable requirements of 40 CFR 60.4208 for importing or installing stationary CI ICE.

[40 CFR 60.4208, Subpart IIII]

28.2. Except as permitted under Condition 28.3:

a. Operate and maintain the stationary CI ICE and control device according to the manufacturer's written instructions over the entire life of the engine;

b. Change only those emission-related settings that are permitted by the manufacturer; and

c. Meet the requirements of 40 CFR part 1068, as they apply to you.

[40 CFR 60.4206 & 60.4211(a), Subpart IIII]

28.3. If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

[40 CFR 60.4211(g), Subpart IIII]

a. For EU IDs 11, 12, and 18, you must 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, you must conduct an initial performance test to demonstrated compliance with the applicable emission standards within 1 year of startup, or within 1 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 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

[40 CFR 60.4211(g)(2) & (g)(3), Subpart IIII]

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[14] The provisions of NSPS Subpart IIII listed in Condition 28 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 this condition.

[15] For the purposes of NSPS Subpart IIII, the date that construction commences is the date the engine is ordered by the owner or operator as defined in 40 CFR 60.4200(a).

b. For EU IDs 12 and 18, conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

[40 CFR 60.4211(g)(3), Subpart IIII]

28.4. Operate EU IDs 11, 12, and 18 according to the requirements in 40 CFR 60.4211(f)(1) through 40 CFR 60.4211(f)(3). In order for the engine to be considered an emergency stationary ICE under NSPS Subpart IIII, 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 40 CFR 60.4211(f)(1) through 40 CFR 60.4211(f)(3), is prohibited. If you do not operate the engine according to the requirements in 40 CFR 60.4211(f)(1) through 40 CFR 60.4211(f)(3), the engine will not be considered an emergency engine under 40 CFR 60 Subpart IIII and must meet all requirements for non-emergency engines.

[40 CFR 60.4211(f), Subpart IIII]

28.5. Comply with the applicable provisions of 40 CFR 60 Subpart A as specified in Table 8 to Subpart IIII.

[40 CFR 60.4218 & Table 8, Subpart IIII]

NSPS Subpart IIII Fuel Requirements

28.6. For EU IDs 11, 12, and 18, the Permittee must use diesel fuel that meets the requirements of 40 CFR 1090.305 for nonroad diesel fuel with the following specifications:

a. Maximum sulfur content of 15 ppm.

b. Diesel fuel must meet one of the following standards:

(i) Minimum cetane index of 40.

(ii) Maximum aromatic content of 35 volume percent.

[40 CFR 60.4207(b), Subpart IIII]
[40 CFR 1090.305, Subpart D]

NSPS Subpart IIII Emission Standards

28.7. The Permittee shall comply with the emission standards in Conditions 28.8 and 28.9 by purchasing an engine certified to the emission standards specified in 40 CFR 60.4205(b) (for EU IDs 12 and 18) and 60.4205(c) (for EU ID 11), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted under Condition 28.3.[16]

[40 CFR 60.4211(c), Subpart IIII]

[16] EU IDs 11, 12, and 18 were identified in the application as certified engines.

28.8. For EU IDs 12 and 18, the Permittee must comply with the Tier 2 emission standards for new nonroad CI engines for the same rated power as described in 40 CFR Part 1039, Appendix I, for all pollutants and the smoke standards, for the same model year and maximum engine power:

a. 6.4 g/kW-hr for NOx + NMHC;

b. 3.5 g/KW-hr for CO;

c. 0.2 g/kW-hr for PM; and

d. Smoke from EU IDs 12 and 18 may not exceed the following standards:

(i) 20 percent during the acceleration mode.

(ii) 15 percent during the lugging mode.

(iii) 50 percent during the peaks in either the acceleration or lugging modes.

[40 CFR 60.4205(b) & 60.4202(a)(2), Subpart IIII]
[40 CFR 1039, Table 2 to Appendix I & 1039.105(b), Subpart I]

28.9. For EU ID 11, the Permittee shall comply with the applicable emission standards in Table 4 to NSPS Subpart IIII, for all pollutants.

a. 4.0 g/kW-hr for NMHC + NOx;

b. 3.5 g/kW-hr for CO; and

c. 0.20 g/kW-hr for PM

[40 CFR 60.4205(c) & Table 4, Subpart IIII]

NSPS Subpart IIII Monitoring and Recordkeeping Requirements

28.10. For EU IDs 11, 12, and 18, the Permittee shall meet the monitoring and recordkeeping requirements as follows:

[18 AAC 50.040(a)(2)(OO), (j)(4) & 50.326(j)]
[40 CFR 71.6(a)(1)& (a)(3)]

a. If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine, if one is not already installed.

[40 CFR 60.4209(a), Subpart IIII]

b. If you are an owner or operator of an emergency stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in Conditions 28.7 and 28.9, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

(i) Keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

[40 CFR 60.4209(b) & 60.4214(c), Subpart IIII]

c. If the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

[40 CFR 60.4214(b), Subpart IIII]

NSPS Subpart IIII Reporting Requirements

28.11. Include with the operating report under Condition 63 records of the operational hours and the reason the engine was in operation as required in Condition 28.10.c for the period covered by the report.

28.12. Report in accordance with Condition 62 if any of the requirements in Conditions 28.1 through 28.10 were not met.

[18 AAC 50.040(j)(4) & 50.326(j)(4)]
[40 CFR 71.6(a)(3)(iii) & (c)(6)]

NSPS Subpart JJJJ – Spark Ignition Internal Combustion Engines

NSPS Subpart JJJJ Applicability and Compliance Requirements

29. For EU IDs 1 through 10, the Permittee shall comply with all applicable requirements of NSPS Subpart JJJJ for stationary spark ignition (SI) internal combustion engine whose construction, modification, or reconstruction commences after June 12, 2006.

[18 AAC 50.040(a)(2)(PP), (j)(4) & 50.326(j)]
[40 CFR 71.6(a)(1)]
[40 CFR 60.4230, Subpart JJJJ]

29.1. Operate and maintain stationary SI ICE that achieve the emission standards as required in Condition 29.4 over the entire life of the engine.

[40 CFR 60.4234, Subpart JJJJ]

29.2. Comply with the applicable provisions of NSPS Subpart A as specified in Table 3 to Subpart JJJJ.

[40 CFR 60.4246 & Table 3, Subpart JJJJ]

29.3. For EU ID 1 through 10, the Permittee shall comply with the following:

a. You must 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, you must conduct an initial performance test within 1 year of engine startup and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance with the emission standards in Condition 29.4.

[40 CFR 60.4243(b)(2)(ii), Subpart JJJJ]

b. **Performance Test Waiver**. As allowed under the performance test waiver approved by EPA Region 10 on March 12, 2018, the Permittee may elect to test only two of EU IDs 1 through 10 in lieu of the testing requirement in Condition 29.3.a, to demonstrate compliance with the emission standards in Condition 29.4. This waiver is subject to Conditions 29.3.b(i) through 29.3.b(v) and automatically terminates if these conditions are not met:

(i) During each scheduled performance test, at least two of the Wärtsilä 18V50DF engines covered by the waiver shall be tested. After any five consecutive performance tests (or one half the sum of the remaining engines, rounding up to a whole number if necessary, if any engines have been retired from service or have become ineligible for the waiver), all of the Wärtsilä 18V50DF engines covered by the waiver shall have been tested.

(ii) The Permittee shall perform each subsequent test of its Wärtsilä 18V50DF engines within three years from the date of the previous test, or before such a time that any Wärtsilä 18V50DF engine covered by the waiver has operated 8,760 hours from the date of the previous test, whichever comes first.

(iii) The units must remain subject to federally-enforceable permit requirements that provide for continuous operation of the SCR and CatOx systems, continuous monitoring of SCR and CatOx operating parameters, and recordkeeping and reporting requirements that are consistent with Operating Permit AQ1086TVP01, issued, January 27, 2017.

(iv) Emissions of any pollutant regulated by NSPS JJJJ from any tested engine must remain at or below 50 percent of the level of the standard

(v) The units must remain at the Matanuska Electric Assoc. Eklutna Generation Station located southwest of Palmer, Alaska.

[USEPA Region 10 Test Waiver, 3/12/2018]
[40 CFR 60.8(b)(4), Subpart A]

NSPS Subpart JJJJ Emission Standards

29.4. For EU IDs 1 through 10, the Permittee must meet the following emission standards:

[40 CFR 60.4233(e), Subpart JJJJ]

a. 1.0 g/hp-hr (82 ppmvd at 15 percent O_2) for NOx

b. 2.0 g/hp-hr (270 ppmvd at 15 percent O_2) for CO

c. 0.7 g/hp-hr (60 ppmvd at 15 percent O_2) for VOC[17]

[40 CFR 60.4233(e) & Table 1, Subpart JJJJ]

NSPS Subpart JJJJ Testing Requirements

29.5. For EU ID 1 through 10, the Permittee shall comply with the following:

a. Owners and operators of stationary SI ICE who conduct performance tests must follow the procedures in Conditions 29.5.a(i) through 29.5.a(vii) below.

[40 CFR 60.4244, Subpart JJJJ]

(i) Each performance test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and according to the requirements in 40 CFR 60.8 and under the specific conditions that are specified by Table 2 to NSPS Subpart JJJJ.

(ii) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in 40 CFR 60.8(c). If your stationary SI internal combustion engine is non-operational, you do not need to startup the engine solely to conduct a performance test; however, you must conduct the performance test immediately upon startup of the engine.

(iii) You must conduct three separate test runs for each performance test required in this section, as specified in 40 CFR 60.8(f). Each test run must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and last at least 1 hour.

(iv) To determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 1 of 40 CFR 60.4244.

(v) To determine compliance with the CO mass per unit output emission limitation, convert the concentration of CO in the engine exhaust using Equation 2 of 40 CFR 60.4244.

(vi) For purposes of NSPS Subpart JJJJ, when calculating emissions of VOC, emissions of formaldehyde should not be included. To determine compliance with the VOC mass per unit output emission limitation, convert the concentration of VOC in the engine exhaust using Equation 3 of 40 CFR 60.4244.

[17] For purposes of NSPS Subpart JJJJ, when calculating emissions of volatile organic compounds from EU IDs 1-10, emissions of formaldehyde should not be included. [Table 1 Footnote d, Subpart JJJJ]

(vii) If the owner/operator chooses to measure VOC emissions using either Method 18 of 40 CFR part 60, appendix A, or Method 320 of 40 CFR part 63, appendix A, then it has the option of correcting the measured VOC emissions to account for the potential differences in measured values between these methods and Method 25A. The results from Method 18 and Method 320 can be corrected for response factor differences using Equations 4 and 5 of 40 CFR 60.4244. The corrected VOC concentration can then be placed on a propane basis using Equation 6 of 40 CFR 60.4244.

[40 CFR 60.4244(a) through (g), Subpart JJJJ]

NSPS Subpart JJJJ Notification, Reporting, and Recordkeeping Requirements

29.6. For EU ID 1 through 10, the Permittee must meet the following notification, reporting and recordkeeping requirements.

[40 CFR 60.4245, Subpart JJJJ]

a. Owners and operators of all stationary SI ICE must keep records of the information in Conditions 29.6.a(i) through 29.6.a(iii) of this permit.

[40 CFR 60.4245(a), Subpart JJJJ]

(i) All notifications submitted to comply with NSPS Subpart JJJJ and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary SI ICE is not a certified engine, documentation that the engine meets the emission standards.

[40 CFR 60.4245(a)(1), (2) & (4), Subpart JJJJ]

b. Owners and operators of stationary SI ICE that are subject to performance testing must submit a copy of each performance test as conducted in Condition 29.5.a within 60 days after the test has been completed. Performance test reports using EPA Method 18, EPA Method 320, or ASTM D6348-03 (incorporated by reference - see 40 CFR 60.17) to measure VOC require reporting of all QA/QC data. For Method 18, report results from sections 8.4 and 11.1.1.4; for Method 320, report results from sections 8.6.2, 9.0, and 13.0; and for ASTM D6348-03 report results of all QA/QC procedures in Annexes 1-7.

[40 CFR 60.4245(d), Subpart JJJJ]

29.7. Report in accordance with Condition 62 if any of the requirements in Conditions 29.1 through 29.6 were not met.

40 CFR Part 63 National Emission Standards for Hazardous Air Pollutants (NESHAP)

NESHAP Subpart ZZZZ – Stationary RICE

30. NESHAP Subpart ZZZZ Applicability. For EU IDs 1 through 12 and 18, the Permittee shall comply with the applicable requirements of NESHAP Subpart ZZZZ for stationary reciprocating internal combustion engines (RICE) located at an area source of hazardous air pollutant (HAP) emissions.

[18 AAC 50.040(c)(23), (j)(4) & 50.326(j)]
[40 CFR 71.6(a)(1)]
[40 CFR 63.6585(c) & 63.6590(a)(2)(iii), Subpart ZZZZ]

30.1. The Permittee shall meet the requirements of 40 CFR 63 by meeting the requirements of 40 CFR Part 60 Subpart IIII (under Condition 28), for compression ignition engines (EU IDs 11, 12, and 18) or 40 CFR Part 60 Subpart JJJJ (under Condition 29), for spark ignition engines (1 through 10). No further requirements apply for EU IDs 1 through 12 and 18 under 40 CFR 63.

[40 CFR 63.6590(c)(1), Subpart ZZZZ]

40 CFR Part 61 National Emission Standards for Hazardous Air Pollutants

Subpart A – General Provisions & Subpart M – Asbestos

31. The Permittee shall comply with the requirements set forth in 40 CFR 61.145, 61.150, and 61.152 of Subpart M, and the applicable sections set forth in 40 CFR 61, Subpart A and Appendix A.

[18 AAC 50.040(b)(1) & (2)(F), & 50.326(j)]
[40 CFR 61, Subparts A & M, and Appendix A]

40 CFR Part 82 Protection of Stratospheric Ozone

32. Subpart F – Recycling and Emissions Reduction. The Permittee shall comply with the standards for recycling and emission reduction of refrigerants set forth in 40 CFR 82, Subpart F.

[18 AAC 50.040(d) & 50.326(j)]
[40 CFR 82, Subpart F]

33. Subpart G – Significant New Alternatives. The Permittee shall comply with the applicable prohibitions set out in 40 CFR 82.174 (b) through (d) (Protection of Stratospheric Ozone Subpart G – Significant New Alternatives Policy Program).

[18 AAC 50.040(d) & 50.326(j)]
[40 CFR 82.174(b) through (d), Subpart G]

34. Subpart H – Halon Emission Reduction. The Permittee shall comply with the applicable prohibitions set out in 40 CFR 82.270 (b) through (f) (Protection of Stratospheric Ozone Subpart H – Halon Emission Reduction).

[18 AAC 50.040(d) & 50.326(j)]
[40 CFR 82.270(b) through (f), Subpart H]

NESHAP Applicability Determination Requirements

35. The Permittee shall determine rule applicability and designation of affected sources under National Emission Standards for Hazardous Air Pollutants (NESHAP) for Source Categories (40 CFR 63) in accordance with the procedures described in 40 CFR 63.1(b).

35.1. If an owner or operator of a stationary source who is in the relevant source category determine that the source is not subject to a relevant standard or other requirement established under 40 CFR 63, the owner or operator must keep a record as specified in 40 CFR 63.1(b).

35.2. If a source becomes affected by an applicable subpart of 40 CFR 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 CFR 63.6(c).

35.3. 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 CFR 63.9(b).

[18 AAC 50.040(c)(1), 50.040(j), & 50.326(j)]
[40 CFR 71.6(a)(3)(ii)]
[40 CFR 63.1(b), 63.5(b)(4), 63.6(c)(1), & 63.10(b)(3), Subpart A]

Section 5. General Conditions

Standard Terms and Conditions

36. 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)]

37. 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)]

38. 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)]

39. **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 through 403.

[18 AAC 50.326(j)(1), 50.400, & 50.403]
[AS 37.10.052(b), 11/04; AS 46.14.240, 6/7/03]

40. **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

40.1. potential to emit of **793 tpy**; or

40.2. 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 or 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]

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

41.1. 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 40.2. 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/.

41.2. 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.

41.3. If no estimate is submitted on or before March 31 of each year, emission fees for the next fiscal year will be based on the potential to emit set out in Condition 40.1.

[18 AAC 50.040(j)(4), 50.326(j)(1) & (3), 50.346(b)(1), 50.410, & 50.420]

42. Good Air Pollution Control Practice. The Permittee shall do the following for EU IDs 13, 14, and 17:

42.1. Perform regular maintenance considering the manufacturer's or the operator's maintenance procedures;

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

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

[18 AAC 50.326(j)(3) & 50.346(b)(5)]

43. 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)]

44. 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 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)]

45. 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 CFR 71.6(a)(3)]

45.1. **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 45.

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 45; or

(ii) the Department notifies the Permittee that it has found a violation of Condition 45.

45.2. **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 45; and

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

45.3. **Reporting**. The Permittee shall report as follows:

a. With each stationary source operating report under Condition 63, 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 62.

46. Technology-Based Emission Standard. If an unavoidable emergency, malfunction (as defined in 18 AAC 50.235(d)), or nonroutine repair (as defined in 18 AAC 50.990(64)), causes emissions in excess of a technology-based emission standard[18] listed in Condition 27, 28, 29, or 32 (refrigerants), the Permittee shall

46.1. take all reasonable steps to minimize levels of emissions that exceed the standard; and

46.2. report in accordance with Condition 62.1.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 CFR 71.6(c)(6)]

Open Burning Requirements

47. Open Burning. If the Permittee conducts open burning at this stationary source, the Permittee shall comply with the requirements of 18 AAC 50.065 as follows:

47.1. Keep written records to demonstrate that the Permittee complies with the limitations in this condition and the requirements of 18 AAC 50.065. Upon request by the Department, submit copies of the records; and

47.2. Include this condition in the annual certification required under Condition 64.

[18 AAC 50.065, 50.040(j), & 50.326(j)]
[40 CFR 71.6(a)(3)]

[18] 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 CFR 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

48. **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)]

49. **Operating Conditions.** Unless otherwise specified by an applicable requirement or test method, the Permittee shall conduct source testing

[18 AAC 50.220(b)]

49.1. at a point or points that characterize the actual discharge into the ambient air; and

49.2. 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.

50. **Reference Test Methods.** The Permittee shall use the following test methods when conducting source testing for compliance with this permit:

50.1. 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 CFR 60.

[18 AAC 50.040(a) & 50.220(c)(1)(A)]
[40 CFR 60]

50.2. 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 CFR 63.

[18 AAC 50.040(c) & 50.220(c)(1)(C)]
[40 CFR 63]

50.3. 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 and may use the form in Section 11 to record data.

[18 AAC 50.030 & 50.220(c)(1)(D)]

50.4. 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 CFR 60, Appendix A.

[18 AAC 50.040(a)(3) & 50.220(c)(1)(E)]
[40 CFR 60, Appendix A]

50.5. Source testing for emissions of PM_{10} and $PM_{2.5}$ must be conducted in accordance with the procedures specified in 40 CFR 51, Appendix M, Methods 201 or 201A and 202.

[18 AAC 50.035(b)(2) & 50.220(c)(1)(F)]
[40 CFR 51, Appendix M]

50.6. Source testing for emissions of any pollutant may be determined using an alternative method approved by the Department in accordance with 40 CFR 63 Appendix A, Method 301.

[18 AAC 50.040(c)(24) & 50.220(c)(2)]
[40 CFR 63, Appendix A, Method 301]

51. 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)]

52. Test Exemption. The Permittee is not required to comply with Conditions 54, 55, and 56 when the exhaust is observed for visible emissions by Method 9 Plan (Condition 2.3) or Smoke/No Smoke Plan (Condition 2.4).

[18 AAC 50.345(a)]

53. 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.

54. Test Plans. Except as provided in Condition 52, 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 48 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 performed without resubmitting the plan.

55. Test Notification. Except as provided in Condition 52, 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.

56. Test Reports. Except as provided in Condition 52, within 60 days after completing a source test, the Permittee shall submit two copies 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 59. 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) & (l) through (o)]

57. Particulate Matter Calculations. In source testing for compliance with the particulate matter standards in Conditions 5 and 20.2, 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

58. The Permittee shall keep all records required by this permit for at least five years after the date of collection, including:

58.1. Copies of all reports and certifications submitted pursuant to this section of the permit; and

58.2. 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), (j)(4), & 50.326(j)]
[40 CFR 60.7(f), Subpart A, 40 CFR 71.6(a)(3)(ii)(A) & (B)]

Reporting Requirements

59. **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.

59.1. 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)]

60. **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.

60.1. 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)]

61. **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 CFR 71.5(a)(2) & 71.6(a)(3)]

62. **Excess Emissions and Permit Deviation Reports**. The Permittee shall report excess emissions and permit deviations as follows

62.1. **Excess Emissions Reporting.** Except as provided in Condition 45, 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 62.1.d.

d. Report all other excess emissions not described in Conditions 62.1.a, 62.1.b, and 62.1.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 63 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.

[18 AAC 50.235(a)(2), 50.240(c), 50.326(j)(3), & 50.346(b)(2)]

62.2. **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 4.3.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 63 for permit deviations that occurred during the period covered by the report, whichever is sooner

[18 AAC 50.326(j)(3) & 50.346(b)(2)]

62.3. **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 12 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)]

63. Operating Reports. During the life of this permit[19], the Permittee shall submit to the Department an operating report in accordance with Conditions 59 and 60 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.

63.1. 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.

63.2. When excess emissions or permit deviations that occurred during the reporting period are not included with the operating report under Condition 63.1, the Permittee shall identify

a. the date of the excess emissions or permit deviation;

b. the equipment involved;

c. the permit condition affected;

d. a description of the excess emissions or permit deviation; and

[19] *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.

e. any corrective action or preventive measures taken and the date(s) of such actions.

63.3. When excess emissions or permit deviation reports have already been submitted under Condition 62 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.

63.4. The operating report must include, for the period covered by the report, a listing of emissions monitored under Conditions 2.3.e and 2.4.c, 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.

63.5. **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 50.326(j)(3) & 50.346(b)(6)]
[40 CFR 71.6(a)(3)(iii)(A)]

64. 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 60.

64.1. 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.

64.2. **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.

64.3. 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 CFR 71.6(c)(5)]

65. 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:

65.1. **Annual Inventory**. Each year by April 30, if the stationary source's potential to emit for the previous calendar year equals or exceeds:

a. 250 tons per year (tpy) of NH_3, PM_{10}, $PM_{2.5}$ or VOC; or

b. 2,500 tpy of CO, NO_X or SO_2.

65.2. **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 VOC.

b. For stationary sources located in Nonattainment Areas:

(i) 0.5 tpy of actual Pb, or

(ii) 1,000 TPY of CO or, when located in a CO nonattainment area, 100 tpy of CO; or

(iii) 100 tpy of SO_2, NH_3, PM_{10}, $PM_{2.5}$, NO_x, or VOC; or as specified in Conditions ??

(iv) 70 tpy of SO_2, NH_3, $PM_{2.5}$, NO_x, or VOC in $PM_{2.5}$ serious nonattainment; or

(v) 70 tpy of PM_{10} in PM_{10} serious nonattainment areas; or

(vi) 50 tpy of 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.

65.3. For reporting under Condition 65.2, the Permittee shall report the annual emissions and the required data elements under Condition 65.4 every third year for the previous calendar year as scheduled by the EPA.[20]

65.4. For each emissions unit and the stationary source, include in the report the required data elements[21] 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.

65.5. 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 CFR 51.15, 51.30(a)(1) & (b)(1), & Appendix A to 40 CFR 51 Subpart A]

66. NSPS and NESHAP Reports. The Permittee shall comply with the following:

66.1. **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 63 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.

66.2. **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) & 50.326(j)(4)]
[40 CFR 60.13, 63.10(d) & (f) and 40 CFR 71.6(c)(6)]

[20] The calendar years for which reports are required are based on the triennial reporting schedule in 40 CFR 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.).

[21] The required data elements to be reported to the EPA are outlined in 40 CFR 51.15 and Tables 2a and 2b to Appendix A of 40 CFR 51 Subpart A.

Section 8. Permit Changes and Renewal

67. Permit Applications and Submittals. The Permittee shall comply with the following requirements for submitting application information to the EPA:

67.1. 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;

67.2. 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.

67.3. 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

67.4. 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 CFR 71.10(d)(1)]

68. 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 CFR 71.6(a)(8)]

69. 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 CFR Part 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:

69.1. Each such change shall meet all applicable requirements and shall not violate any existing permit term or condition;

69.2. 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) through (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;

69.3. The change shall not qualify for the shield under 40 CFR 71.6(f);

69.4. 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)]
[40 CFR 71.6(a)(12)]

70. Operational Flexibility. The Permittee may make Section 502(b)(10)[22] 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):

70.1. The Permittee shall provide EPA and the Department with a notification no less than 7 days in advance of the proposed change.

70.2. For each such change, the written notification required above 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.

70.3. The permit shield described in 40 CFR 71.6(f) shall not apply to any change made pursuant to Condition 70.

[18 AAC 50.040(j)(4) & 50.326(j)]
[40 CFR 71.6(a)(13)]

71. Permit Renewal. To renew this permit, the Permittee shall submit to the Department[23] an application under 18 AAC 50.326 no sooner than **August 2, 2025** and no later than **August 2, 2026**. 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 CFR 71.7(b) and 71.5(a)(1)(iii).

[18 AAC 50.040(j)(3), 50.326(c)(2) & (j)(2)]
[40 CFR 71.5(a)(1)(iii) & 71.7(b) & (c)(1)(ii)]

[22] As defined in 40 CFR 71.2, 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.

[23] 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

72. Compliance with permit terms and conditions is considered to be compliance with those requirements that are

72.1. included and specifically identified in the permit; or

72.2. determined in writing in the permit to be inapplicable.

[18 AAC 50.326(j)(3) & 50.345(a) & (b)]

73. 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;

b. permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280; or

c. denial of an operating permit renewal application.

[18 AAC 50.040(j), 50.326(j) and 50.345(a) & (c)]

74. 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) & 50.326(j)]
[40 CFR 71.6(c)(3) & 71.5(c)(8)(iii)(A)]

75. 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) and 50.345(a) & (d)]

76. 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

76.1. enter upon the premises where a source subject to the permit is located or where records required by the permit are kept;

76.2. have access to and copy any records required by the permit;

76.3. inspect any stationary source, equipment, practices, or operations regulated by or referenced in the permit; and

76.4. sample or monitor substances or parameters to assure compliance with the permit or other applicable requirements.

[18 AAC 50.326(j)(3) and 50.345(a) & (h)]

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.

77. Nothing in this permit shall alter or affect the following:

77.1. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section; or

77.2. 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 50.326(j)]
[40 CFR 71.6(f)(3)(i) & (ii)]

78. Table B 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 B 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 50.326(j)]
[40 CFR 71.6(f)(1)(ii)]

Table B - Permit Shields Granted

EU ID	Non-Applicable Requirements	Reason for Non-Applicability
Stationary source-wide	40 CFR 68 Subpart C	Stationary source does not use aqueous ammonia with a concentration of 20% or greater.

[18 AAC 50.326(j)][40 CFR 71.6(f)(1)(ii)]

Section 11. Visible Emissions Form

VISIBLE EMISSION OBSERVATION FORM

This form is designed to be used in conjunction with EPA Method 9, "Visual Determination of the Opacity of Emissions form Stationary Sources." Temporal changes in emission color, plume water droplet content, background color, sky conditions, observer position, etc. should be noted in the comments section adjacent to each minute of readings. Any information not dealt with elsewhere on the form should be noted under additional information. Following are brief descriptions of the type of information that needs to be entered on the form. For a more detailed discussion of each part of the form, refer to "Instructions for Use of Visible Emission Observation Form." (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

Emission Unit Location

City | State | Zip

Phone # (Key Contact) | Stationary Source ID Number

Process Equipment | Operating Mode

Control Equipment | Operating Mode

Describe Emission Point/Location

Height above ground level | Height relative to observer | Clinometer Reading

Distance From Observer (Start / End) | Direction From Observer (Start / End)

Describe Emissions & Color (Start / End)

Visible Water Vapor Present? No Yes | If yes, determine approximate distance from the stack exit to w here the plume w as read

Point in Plume at Which Opacity Was Determined

Describe Plume Background (Start / End) | Background Color (Start / End)

Sky Conditions: (Start / End)

Wind Speed (Start / End) | Wind Direction From (Start / End)

Ambient Temperature | Wet Bulb Temp | RH percent

SOURCE LAYOUT SKETCH: 1 Stack or Point Being Read 2 Wind Direction From 3 Observer Location 4 Sun Location 5 North Arrow 6 Other Stacks

Observation Date | Start Time | End Time

Min \ Sec	0	15	30	45	Comments
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					

Range of Opacity

Minimum | Maximum

I have received a copy of these opacity observations

Print Name:

Signature:

Title | Date

Print Observer's Name

Observer's Signature | Date

Observer's Affiliation:

Certifying Organization

Certified By: | Date

Data Reduction:

Duration of Observation Period (minutes):	Duration Required by Permit (minutes):
Number of Observations:	Highest Six –Minute Average Opacity (%):
Number of Observations exceeding 20%:	
In compliance with six-minute opacity limit? (Yes or No)	Highest 18-Consecutive –Minute Average Opacity (%)(engines and turbines only)

Average Opacity Summary:

Set Number	Time			Opacity		Comments
	Start	End		Sum	Average	

Section 12. Notification Form

Eklutna Generation Station	AQ1086TVP02
Stationary Source (Facility) Name	**Air Quality Permit Number**
Matanuska Electric Association, Inc.	
Company Name	**Date**

When did you discover the Excess Emissions/Permit Deviation?

Date: ______ / ______ / _________ Time: ______ :/ ______

When did the event/deviation occur?

Begin Date: _____ / _____ / ________ Time: ______ : _______ (please use 24-hr clock)

End Date _____ / _____ / ________ Time: ______ : _______ (please use 24-hr clock)

What was the duration of the event/deviation? ____ : _____ (hrs:min) or ______ days

(total # of hrs, min, or days, if intermittent then include only the duration of the actual emissions/deviation)

Reason for Notification: (please check only 1 box and go to the corresponding section)

☐ Excess Emissions – Complete Section 1 and Certify

Note: All "excess emissions" are also "permit deviations." However, use only Section 1 for events that involve excess emissions

☐ Deviation from Permit Condition – Complete Section 2 and Certify

Note: Use only Section 2 for permit deviations that do not involve excess emissions.

☐ Deviation from COBC[24], CO[25], or Settlement Agreement - Complete Section 2 and Certify

[24] Compliance Order By Consent

[25] 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 ☐ Schedule Maintenance/Equipment Adjustment

☐ 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 Involved**:

Identify the emissions unit 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):

- ☐ Opacity ______ %
- ☐ Venting ________ gas/scf
- ☐ Control Equipment Down
- ☐ Fugitive Emissions
- ☐ Emission Limit Exceeded
- ☐ Other ______________
- ☐ Marine Vessel Opacity
- ☐ Flaring

____

(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 Unit Involved**:

Identify the emissions unit involved in the event, using the same identification number and name as in the permit. List the corresponding permit conditions 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 59.)*

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 59).

[18 AAC 50.346(b)(3)]

Attachment E

Electronic Files