Golden Valley Electric Association
PO Box 71249, Fairbanks, AK 99707-1249 • (907) 452-1151 • www.gvea.com
Your Touchstone Energy® Cooperative

June 9, 2020

Certified Mail
Return Receipt Requested
7019 0140 0001 0139 6891

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

Subject: North Pole Power Plant – Revision to Title I Air Quality Permit No. AQ0110CPT01, Rev 1 for Permit Conditions Required by the Fairbanks $PM_{2.5}$ Serious State Implementation Plant (SIP).

Dear Permit Intake Clerk,

Golden Valley Electric Association (GVEA) is submitting the enclosed Title I revision application to request a revision to Title I Air Quality Permit No. AQ011CPT01, Rev 1 under 18 AAC 50.508(6) for the North Pole Power Plant to establish permit conditions as required in the Fairbanks $PM_{2.5}$ Serious SIP, adopted November 19, 2019 by the Alaska Department of Environmental Conservation (ADEC).

Should you have any questions or require additional information, please contact me at 907-458-4557 or NMKnight@gvea.com

Sincerely,

Naomi Morton Knight, P.E.
Environmental Officer

Enclosure

cc: C. Kimball, SLR
dec.aq.airreports@alaska.gov

Title I Air Quality Permit Application

North Pole Power Plant

Prepared for:

Golden Valley Electric Association

June 2020

Title I Air Quality Permit Application

Prepared for:
Golden Valley Electric Association
P.O Box 71249
Fairbanks, Alaska 99707

Prepared by:
SLR International Corporation
543 3rd Ave, Suite 235
Fairbanks, Alaska 99701

June 2020

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Required Elements for Minor Permit Application under 18 AAC 50.508(6)

The following table provides a summary of the required elements for a minor permit establishing for revising or rescinding permit conditions under 18 AAC 50.508(6).

Minor Permit Application Elements

Regulatory Citation	Requirement	Location
18 AAC 50.540(b)	General Information	SSID Form
18 AAC 50.540(k)(1)	Copy of Title I permit	Attachment C
18 AAC 50.540(k)(2)	Explanation of why permit term or condition should be revised or rescinded	Attachment A
18 AAC 50.540(k)(3)	Effect of revising or revoking the permit term or condition on emissions, other permit terms, and compliance monitoring	Attachments A and B
18 AAC 50.540(k)(4)	For a condition that allows an owner or operator to avoid a permit classification, the information required of an applicant for that type of permit, unless the revised condition would also allow the owner or operator to avoid the classification.	Not Applicable

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Alaska Department of Environmental Conservation
Air Quality Minor Permit Application

STATIONARY SOURCE IDENTIFICATION FORM

Section 1 Stationary Source Information

Name: North Pole Power Plant			SIC:4911
Project Name (if different): Serious PM2.5 SIP Requirements	Contact: Naomi Morton Knight, P.E.		
Physical Address: 1500 H & H Lane	City: North Pole	State: AK	Zip: 99705
	Telephone: 907-458-4557		
	E-Mail Address: NMKnight@gvea.com		
UTM Coordinates (m) or Latitude/Longitude:	Northing:	Easting:	Zone:
	Latitude: 64.73444° N	Longitude: -147-3453° W	

Section 2 Legal Owner

Name: Golden Valley Electric Association		
Mailing Address: PO Box 71249		
City: Fairbanks	State: AK	Zip: 99707
Telephone #:		
E-Mail Address:		

Section 3 Operator *(if different from owner)*

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

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

Name: Frank E. Perkins, Vice President of Power Supply		
Mailing Address: PO Box 71249		
City: Fairbanks	State: AK	Zip: 99707
Telephone #: 907-458-5780		
E-Mail Address: feperkins@gvea.com		

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

Name: Naomi Morton Knight, P.E. Environmental Officer		
Mailing Address: PO Box 71249		
City: Fairbanks	State: AK	Zip: 99707
Telephone #: 907-458-4557		
E-Mail Address: NMKnight@gvea.com		

Section 6 Application Contact

Name: Courtney Kimball			
Mailing Address: 543 3rd Avenue, Suite 235	City: Fairbanks	State: AK	Zip: 99701
	Telephone: 907-452-2280		
	E-Mail Address: ckimball@slrconsulting.com		

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: AQ0110CPT01, Revision 1 Condition No. Various
  Date: 5/3/2006

**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)*: AQ0110TVP04
AQ0110CPT01, Rev 1
9531-AA003

☐ 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.

Golden Valley Electric Association (GVEA) requests a revision to Title I Air Quality Permit No. AQ0110CPT01, Rev 1 under 18 AAC 50.508(6) for the North Pole Power Plant (NPP) stationary source to establish permit conditions as required in the Fairbanks $PM_{2.5}$ Serious State Implementation Plan (Serious SIP), adopted November 19, 2019 by the Alaska Department of Environmental Conservation (ADEC). GVEA requests that ADEC incorporate the applicable SIP limits and SIP Best Available Control Technology (BACT) limits as requested in Attachment A.

Provided below is a summary of the requested limits to be established as permit conditions. Attachment A also provides the requested monitoring, recordkeeping, and reporting requirement for the proposed limits and permit conditions.

- For emission unit (EU) IDs 1 and 2 immediately after Air Quality Stage Alert 1 and 2 are announced and for long as the air episode exists, limit the sulfur content of the fuel delivered to 1,000 parts per million by weight (ppmw), beginning no later than October 1, 2020.
- For EU IDs 1 and 2, limit the sulfur content of the fuel to 15 ppmw (ultra low sulfur diesel (ULSD)) beginning no later than October 1, 2023.
- Except during startup for EU IDs 5 and 6, limit the sulfur content of the fuel to 50 ppmw sulfur beginning no later than June 9, 2021.
- For EU ID 7, limit the sulfur content of the fuel to 0.05 percent by weight beginning no later than June 9, 2021.

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 A

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

- Emissions;
  See Attachment B
- Other permit terms;
  See Attachment B
- The underlying ambient demonstration, if any;
  Not Applicable
- 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)]

Information required under 18 AAC 50.540(k)(4) is not applicable to this permit application because the requested permit conditions do not avoid a permit classification or request revision of an existing permit condition that avoids a permit classification.

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 North Pole Power Plant (Stationary Source Name) submitted to the Department on: June 9, 2020

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: 6/9/2020
Printed Name: Frank E. Perkins	Title: Vice President of Power Supply

Section 15 Attachments

☒ Attachments Included. List attachments:
- A – Permit Revision Requests
- B – Emission Unit Inventory and Emissions Calculations
- C – Copy of Permit No. AQ0110CPT01, Revision 1

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

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Attachment A

Title I Permit Revision Request under 18 AAC 50.508(6)

Attachment A-1: Title I Permit Revision Request under 18 AAC 50.508(6)

Attachment A-2: Fuel Sulfur Content SIP Limit Effective No Later Than October 1, 2020

Attachment A-3: Fuel Sulfur Content SIP Limit Effective No Later Than October 23, 2023

Attachment A-4: Fuel Sulfur Content SIP Limit Effective No Later Than June 9, 2021

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Attachment A-1
Title I Permit Revision Request under 18 AAC 50.508(6)

An application for a minor air quality permit to establish a revision to a Title I permit under 18 Alaska Administrative Code (AAC) 50.508(6) must include the information required under 18 AAC 50.540(k). Each required element is addressed below or within this application.

Golden Valley Electric Association (GVEA) requests that Alaska Department of Environmental Conservation (ADEC) issue a separate minor permit as a revision to Permit No. AQ0110CPT01, Revision 1 to align with the SIP BACT limit requirements summarized in the Fairbanks $PM_{2.5}$ Serious SIP Vol. II:III.D.7.7 control strategies document adopted November 19, 2019. The permit conditions requested are presented in Attachment A-2 through A-4.

18 AAC 50.540(k)(1)

Per 18 AAC 50.540(k)(1), a copy of Title I Air Quality Permit No. AQ0110CPT01, Revision 1 is provided in Attachment C.

18 AAC 50.540(k)(2)

GVEA is requesting a new Title I minor permit containing conditions which incorporate the limits adopted in the SIP for EU IDs 1, 2 and 5 through 7. Provided in Attachment A-2 through A-4 are proposed permit conditions to be incorporated into the new permit for the stationary source to comply with the SIP limits and SIP BACT limit requirements summarized in the Fairbanks $PM_{2.5}$ Serious SIP Vol. II:III.D.7.7 control strategies document.

18 AAC 50.540(k)(3)

Per 18 AAC 50.540(k)(3), the effects on the stationary source's emissions due to the requested permit terms are presented in Attachment B. Attachment B provides the sulfur dioxide (SO_2) potential to emit (PTE) calculations under currently permitted requirements and the SO_2 PTE calculations which incorporate the various SIP requirements. A fuel sulfur limit of 0.05 percent by weight for EU IDs 5 and 6 is provided for naphtha under Condition 20.1 of Permit AQ0110TVP04. GVEA typically receives naphtha from Petro Star North Pole Refinery (Petro Star) under a long-term contract that limits fuel sulfur to 30 ppmw (0.003 percent sulfur by weight) under the terms of the contract. The fuel sulfur limit provided in the contract between GVEA and Petro Star was used to calculate assessable emissions for naphtha in the Title V operating permit renewal application submitted in September 2018. However, for comparison of emissions for this application the permitted limit prior to the SIP limit change has been used for existing PTE calculations.

The particulate matter less than 2.5 microns ($PM_{2.5}$) SIP emission limits for EU IDs 1, 2, 5, 6, 7, 11 and 12 and the SO_2 SIP emission limits for EU IDs 11 and 12 are consistent with existing operations and PTE calculations. Incorporating the $PM_{2.5}$ and SO_2 SIP requirements for these emissions units does not change the $PM_{2.5}$ or SO_2 potential to emit as submitted in the September 2018 Title V operating permit renewal application. The requested permit conditions do not have other effects on other permit terms, underlying ambient demonstration, or the existing compliance monitoring of the existing permit terms due to the proposed changes.

18 AAC 50.540(k)(4)

Information required under 18 AAC 50.540(k)(4) is not applicable to this permit application because the requested permit conditions do not avoid a permit classification.

Attachment A-2
New Permit Condition under 18 AAC 50.508(6)
Fuel Sulfur Content SIP Limit Effective No Later Than October 1, 2020

GVEA is requesting a new permit condition to limit the sulfur content of fuel oil received at the stationary source beginning on October 1, 2020, in accordance with the limits summarized in Vol. II: III.D.7.7 Section 7.7.8.5, Table 7.7-15 of the SIP. Since the proposed change only occurs during Air Quality Stage Alert 1 and 2 episodes, potential emissions do not change. Calculations of the stationary source's potential to emit and the allowable emissions are provided in Attachment B. GVEA will demonstrate compliance with the proposed limit through the monitoring, recordkeeping, and reporting requirements proposed below as a new permit condition.

1. Beginning no later than October 1, 2020, the Permittee shall limit the sulfur content of fuel oil delivered to the stationary source for EU IDs 1 and 2 to no greater than 1,000 ppmw (S1000) immediately after Air Quality Stage Alert 1 and 2 are announced and for as long as the air episode exists.

    1.1 Upon receipt of each shipment of fuel obtain a certified statement from the supplier with the following information:

    a. The sulfur content in the fuel oil (ppmw);

    b. The method of analysis; and

    c. A statement that the analysis was representative of the fuel oil delivered.

    1.2 If a certificate is not available from the supplier, analyze a representative sample of the fuel to determine the sulfur content using an appropriate method listed in 18 AAC 50.035 or another method approved in writing by the Department.

    1.3 The Permittee shall keep records of the sulfur contents of each shipment of fuel under Condition 1.1.

    1.4 Include a statement in the operating report, required by the operating permit issued to the stationary source under AS 46.14.130(b) and 18 AAC 50, affirming that the fuel delivered did not exceed the limit in Condition 1.

    1.5 Report in accordance with the Excess Emissions and Permit Deviation condition in the applicable operating permit issued for the stationary source under AS 46.14.130(b) and 18 AAC 50 whenever the sulfur content of a shipment of fuel exceeded the limit in Condition 1.

Attachment A-3
New Permit Condition under 18 AAC 50.508(6)
Fuel Sulfur Content SIP Limit Effective No Later Than October 23, 2023

GVEA is requesting a new permit condition to limit the sulfur content of liquid fuel burned in EU IDs 1 and 2 beginning on October 1, 2023, in accordance with the limits summarized in Vol. II: III.D.7.7 Section 7.7.8.5, Table 7.7-15 of the SIP. Calculations demonstrating the effect the limit will have on the stationary source's potential to emit and the allowable emissions are provided in Attachment B. GVEA will demonstrate compliance with the proposed limit through the monitoring, recordkeeping, and reporting requirements proposed below as a new permit condition.

2. No later than October 1, 2023, the Permittee shall limit the sulfur content of fuel oil combusted in EU IDs 1 and 2 to no greater than 15 ppmw (ULSD) between October 1 and March 31.

   2.1 For each shipment of fuel, keep receipts that specify fuel grade, date, and quantity of fuel received.

   2.2 Include a statement in the operating report, required by the operating permit issued to the stationary source under AS 46.14.130(b) and 18 AAC 50, affirming that EU IDs 1 and 2 only burned ULSD from October 1 through March 31 during the reporting period.

   2.3 Report in accordance with the Excess Emissions and Permit Deviation condition in the applicable operating permit issued for the stationary source under AS 46.14.130(b) and 18 AAC 50 whenever the sulfur content of the liquid fuel burned in EU IDs 1 or 2 exceeds 15 ppmw.

Attachment A-4
New Permit Condition under 18 AAC 50.508(6)
Fuel Sulfur Content SIP Limit Effective No Later Than June 9, 2021

GVEA is requesting a new permit condition to limit the sulfur content of fuel burned in EU IDs 5 and 6 beginning on or after June 9, 2021, in accordance with the limits summarized in Vol. II: III.D.7.7 Section 7.7.8.5, Table 7.7-15 of the SIP. Calculations demonstrating the effect the limit will have on the stationary source's potential to emit and the allowable emissions are provided in Attachment B. GVEA will demonstrate compliance with the proposed limit through the monitoring, recordkeeping, and reporting requirements proposed below as a new permit condition.

3. No later than June 9, 2021, limit the sulfur content of the fuel combusted in EU IDs 5 through 7 as follows.
   - 3.1 Limit the sulfur content of the fuel combusted in EU IDs 5 and 6 to no greater than 50 ppmw (light straight run turbine fuel), except during startup.
   - 3.2 Limit the sulfur content of the fuel combusted in EU ID 7 to no greater than 0.05 percent by weight.
   - 3.3 Upon receipt of each shipment of fuel obtain a certified statement from the supplier with the following information:
     - 3.3.1 The sulfur content in the fuel oil (ppmw or wt. pct.);
     - 3.3.2 The method of analysis; and
     - 3.3.3 A statement that the analysis was representative of the fuel delivered.
   - 3.4 If a certificate is not available from the supplier, analyze a representative sample of the fuel to determine the sulfur content using an appropriate method listed in 18 AAC 50.035 or another method approved in writing by the Department.
   - 3.5 The Permittee shall keep records of the sulfur contents of each shipment of fuel under Conditions 3.1 and 3.2.
   - 3.6 Report in accordance with the Excess Emissions and Permit Deviation condition in the applicable operating permit issued for the stationary source under AS 46.14.130(b) and 18 AAC 50 whenever the sulfur content of a shipment of fuel for EU IDs 5 through 7 exceeded the limits in Conditions 3.1 or 3.2.

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Attachment B

Potential to Emit SO_2 Calculations Tables

Table B-1: Air Quality Minor Permit Emissions Summary

Table B-2: Emission Unit Parameters

Table B-3: Existing Potential to Emit Calculations - Sulfur Dioxide (SO_2) Emissions

Table B-4: Potential to Emit Calculations Effective June 9, 2021 - Sulfur Dioxide (SO_2) Emissions

Table B-5: Potential to Emit Calculations Effective October 1, 2023 - Sulfur Dioxide (SO_2) Emissions

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Table B-1. Air Quality Minor Permit Emissions Summary
Golden Valley Electric Association - North Pole Power Plant

Pollutant [1]	Existing Potential to Emit (PTE) [2]	PTE beginning October 1, 2020 [3]	PTE beginning June 9, 2021 [4]	PTE beginning October 1, 2023 [5]
SO_2	2,527 tpy	2,527 tpy	2,355 tpy	1,574 tpy

Notes:

[1] The permit conditions requested in this minor permit application do not change the NO_x, CO, PM_{10}, $PM_{2.5}$, HAPs, and greenhouse gas emissions potential to emit calculations submitted in the September 2018 Title V operating permit renewal application.

[2] The detailed existing PTE calculations are provided in Table B-3.

[3] The PTE beginning October 1, 2020 will not change. The sulfur limit for EU IDs 1 and 2 that is effective beginning October 1, 2020 only goes into effect during Stage 1 and 2 episodes. Therefore, worst case emissions are equivalent to the existing configuration.

[4] The detailed PTE calculations beginning June 9, 2021 are provided in Table B-4. The PTE beginning June 9, 2021 incorporates the SO2 SIP requirements which limit the sulfur content of the fuel combusted in EU IDs 5 and 6 to 50 ppmw and in EU ID 7 to 0.05 wt. pct.

[5] The detailed PTE calculations beginning October 1, 2023 are provided in Table B-5. The PTE beginning October 1, 2023 incorporates the SO_2 SIP requirements which limit the sulfur content of the fuel combusted in EU IDs 1 and 2 to 15 ppmw (ultra low sulfur diesel (ULSD)) during the months of October through March.

Table B-2. Emission Unit Parameters
Golden Valley Electric Association - North Pole Power Plant

Emission Unit			Fuel	Electrical Output	Rating	Potential	Install
ID	Description	Make/Model	Type	Rating		Operation	Date
Significant Emission Units							
1	Simple Cycle Gas Turbine	GE Frame 7, Series 7001, Model BR	Fuel Oil	60.5 MW	672 MMBtu/hr	5,411 hr/yr [1]	1976
2	Simple Cycle Gas Turbine	GE Frame 7, Series 7001, Model BR	Fuel Oil	60.5 MW	672 MMBtu/hr	7,992 hr/yr [2]	1977
5	Combined Cycle Gas Turbine	GE LM6000PC	Jet A/Diesel #1 (startup)	43 MW	455 MMBtu/hr	1,500,000 gal/yr [3]	2005
			Naphtha/LSR			8,302 hr/yr [4]	
6	Combined Cycle Gas Turbine	GE LM6000PC	Jet A/Diesel #1 (startup)	43 MW	455 MMBtu/hr	1,500,000 gal/yr [3]	TBD
			Naphtha/LSR			8,302 hr/yr [4]	
7	Emergency Generator Engine	Mitsubishi 0A8829	No. 2 Diesel	N/A	564.6 hp	52 hr/yr [5]	2005
11	Boiler	Bryan Steam RV500	Propane	N/A	5.0 MMBtu/hr	8,760 hr/yr	2005
12	Boiler	Bryan Steam RV500	Propane	N/A	5.0 MMBtu/hr	8,760 hr/yr	
Insignificant Emission Units							
N/A	Burnham 17 A-T Boiler [6]		Heating Oil	N/A	0.222 MMBtu/hr	8,760 hr/yr	1995
3	Fuel Oil Storage Tank		Diesel	N/A	50,000 gallons	8,760 hr/yr	1995
4	Fuel Oil Storage Tank		Diesel	N/A	50,000 gallons	8,760 hr/yr	1995
N/A	Fuel Oil Storage Tank No. 1 Heater 1- Steel Vessel		Diesel	N/A	180 gallons	8,760 hr/yr	1978
N/A	Fuel Oil Storage Tank No. 1 Heater 2- Steel Vessel		Diesel	N/A	180 gallons	8,760 hr/yr	1978
N/A	Fuel Oil Storage Tank No. 2 Heater 1- Steel Vessel		Diesel	N/A	200 gallons	8,760 hr/yr	1978
N/A	Fuel Oil Storage Tank No. 2 Heater 2- Steel Vessel		Diesel	N/A	200 gallons	8,760 hr/yr	1978
N/A	Fuel Oil Storage Tank No. 1 Filter 1- Steel Vessel		Diesel	N/A	80 gallons	8,760 hr/yr	1995
N/A	Fuel Oil Storage Tank No. 1 Filter 2- Steel Vessel		Diesel	N/A	80 gallons	8,760 hr/yr	1995
N/A	Fuel Oil Storage Tank No. 2 Filter 1- Steel Vessel		Diesel	N/A	80 gallons	8,760 hr/yr	1995
N/A	Fuel Oil Storage Tank No. 2 Filter 2- Steel Vessel		Diesel	N/A	80 gallons	8,760 hr/yr	1995
N/A	Heating Oil Storage Tank		Heating Oil	N/A	1,000 gallons	8,760 hr/yr	Unknown
N/A	Fuel Oil Storage Tank Filter 1- Steel Vessel		Diesel	N/A	160 gallons	8,760 hr/yr	1995
N/A	Fuel Oil Storage Tank Filter 2-Steel Vessel		Diesel	N/A	160 gallons	8,760 hr/yr	1995
N/A	Emergency Generator Engine Tank		Diesel	N/A	2,500 gallons	8,760 hr/yr	2006
N/A	Emergency Generator Engine Day Tank		Diesel	N/A	275 gallons	8,760 hr/yr	2006

Notes:

1 EU IDs 1, 5, and 6 are limited to 1,600 tpy NO_X on a 12-month rolling basis per Condition 19 of Permit No. AQ0110TVP04. As a result, EU ID 1 can operate no more than 5,411 hours per 12-month rolling period. The potential operation of 5,411 hr/yr was determined as follows:

Potential Operation, hr/yr= (NO_X emission limit, 1,600 tpy) x (Conversion, 2,000 lb/ton) / (NO_X emission rate, 0.88 lb/MMBtu) / (Capacity, 672 MMBtu/hr)

2 EU ID 2 is limited to 7,992 hours of operation on a 12-month rolling basis per Condition 18 of Permit No. AQ0110TVP04.

3 Startup fuel for EU IDs 5 and 6 is limited to 1.5 million gallons per year under Condition 20.1 of Permit AQ0110TVP04. The use of 1.5 million gallons per year is equivalent to 458 hours per year.

4 Under a worst-case scenario using 1,500,000 gallons of No. 1 Diesel startup fuel during a 12-month rolling period, approximately 8,302 hours remain.

5 EU ID 7 is limited to 52 hours of operation on a 12-month rolling basis per Condition 15 of Permit No. AQ0110TVP04.

6 The Burnham 17 A-T Boiler is considered a hot water boiler as indicated in the definition of hot water heater provided in 40 CFR 63.11237, and is therefore exempt from 40 CFR 63 Subpart JJJJJJ.

Table B-3. Existing Potential to Emit Calculations - Sulfur Dioxide (SO_2) Emissions
Golden Valley Electric Association - North Pole Power Plant

Emission Unit ID	Emission Unit Description	Maximum Capacity	Fuel Type	Factor Reference	Maximum Fuel Sulfur Content	SO_2 Emission Factor	Allowable Annual Operation	Potential Emissions
Significant Emission Units								
1	Simple Cycle Gas Turbine	672 MMBtu/hr	Fuel Oil	AP-42 Table 3.1-2a	0.5 wt. pct. S	0.505 lb/MMBtu	5,411 hr/yr	918.18 tpy
2	Simple Cycle Gas Turbine	672 MMBtu/hr	Fuel Oil	AP-42 Table 3.1-2a	0.5 wt. pct. S	0.505 lb/MMBtu	7,992 hr/yr	1,356.08 tpy
5	Combined Cycle Gas Turbine	455 MMBtu/hr	Jet A/Diesel #1 (startup)	Mass Balance (startup)	0.3 wt. pct. S	0.041 lb/gal	1,500,000 gal/yr	30.60 tpy
			Naphtha/LSR	AP-42 Table 3.1-2a (non-startup)	0.05 wt. pct. S [1]	0.051 lb/MMBtu	8,302 hr/yr	95.38 tpy
6	Combined Cycle Gas Turbine	455 MMBtu/hr	Jet A/Diesel #1 (startup)	Mass Balance (startup)	0.3 wt. pct. S	0.041 lb/gal	1,500,000 gal/yr	30.60 tpy
			Naphtha/LSR	AP-42 Table 3.1-2a (non-startup)	0.05 wt. pct. S [1]	0.051 lb/MMBtu	8,302 hr/yr	95.38 tpy
7	Emergency Generator Engine	32.0 gal/hr [2]	No. 2 Diesel	Mass Balance	0.1 wt. pct. S	0.015 lb/gal	52 hr/yr	1.2E-02 tpy
11	Boiler	5.0 MMBtu/hr	Propane	Mass Balance	1.9E-07 wt. pct. S	1.6E-08 lb/gal	8,760 hr/yr	3.8E-06 tpy
12	Boiler	5.0 MMBtu/hr	Propane	Mass Balance	1.9E-07 wt. pct. S	1.6E-08 lb/gal	8,760 hr/yr	3.8E-06 tpy
							Significant Emission Units Total Assessable Potential to Emit - SO_2	**2,526.2 tpy**
Insignificant Emission Units								
N/A	Burnham 17 A-T Boiler [6]	0.222 MMBtu/hr	Heating Oil	Mass Balance	0.5 wt. pct. S	0.073 lb/gal	8,760 hr/yr	0.51 tpy
3	Fuel Oil Storage Tank	50,000 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
4	Fuel Oil Storage Tank	50,000 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 1 Heater 1- Steel Vessel	180 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 1 Heater 2- Steel Vessel	180 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 2 Heater 1- Steel Vessel	200 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 2 Heater 2- Steel Vessel	200 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 1 Filter 1- Steel Vessel	80 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 1 Filter 2- Steel Vessel	80 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 2 Filter 1- Steel Vessel	80 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 2 Filter 2- Steel Vessel	80 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Heating Oil Storage Tank	1,000 gallons	Heating Oil	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank Filter 1- Steel Vessel	160 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank Filter 2-Steel Vessel	160 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Emergency Generator Engine Tank	2,500 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Emergency Generator Engine Day Tank	275 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
							Insignificant Emission Units Total Assessable Potential to Emit - SO_2	**0.51 tpy**
							Total Assessable Potential to Emit - SO_2	**2,526.7 tpy**

Notes:

[1] A fuel sulfur limit of 0.05 percent by weight for EU IDs 5 and 6 is provided for naphtha under Condition 20.1 of Permit AQ0110TVP04. However, GVEA receives naphtha from PSI under a long-term contract that limits fuel sulfur to 30 ppmw (0.003 percent sulfur by weight) under the terms of the contract. The fuel sulfur limit provided in the contract between GVEA and PSI was used to calculate assessable emissions for naphtha in the Title V renewal application submitted in September 2018. However, for comparison of emissions for this application the permitted limit prior to the SIP limit change has been used.

[2] The engine specification datasheet indicates a maximum fuel throughput of 32 gal/hr.

Sample Calculations:

Molar mass ratio is 32 lb S/mol : 64 lb SO_2/mol

Stoichiometry: 1 mol S = 1 mol SO_2

Mass Balance Emission Factor, lb/gal = (Molar mass ratio, 2 lb SO_2:1 lb S) x (weight % S in fuel) x (density of fuel, lb/gal) / 100%

Turbine Emissions, tpy= (Emission factor, lb/MMBtu) x (Rating, MMBtu/hr) x (Operation, hr/yr) / (2,000 lb/ton)

Engine Emissions, tpy= (Emission factor, lb/gal) x (Capacity, gal/hr) x (Operation, hr/yr) / (2,000 lb/ton)

Boiler Emissions, tpy= (Emission factor, lb/gal) / (HHV, MMBtu/gal) x (Rating, MMBtu/hr) x (Operation, hr/yr) / (2,000 lb/ton)

Boiler wt. pct. S= (Sulfur compound content, 120 ppmv SO2) x (Conversion, 1.66E-7 lb SO2/scf / ppm SO2) x (F-factor, 8,710 scf/MMBtu) x (Conversion, 0.0216 MMBtu/lb) x (Conversion, mole SO2/64 lb SO2) x (Conversion, mole S/mole SO2) x (Conversion, 32 lb S/ mole S)

Engineering Data:

HHV Propane=	0.091	MMBtu/gal	(40 CFR 98 Table C-1)
HHV No. 1 Diesel=	0.139	MMBtu/gal	(40 CFR 98 Table C-1)
HHV No. 2 Diesel=	0.138	MMBtu/gal	(40 CFR 98 Table C-1)
Heat Content of Propane=	0.0216	MMBtu/lb	(https://www.engineeringtoolbox.com/heating-values-fuel-gases-d_823.html)
Jet A and No. 1 Diesel Density=	6.8	lb/gal	
No. 2 Diesel Density=	7.3	lb/gal	
Propane Density=	4.2	lb/gal	

Table B-4. Potential to Emit Calculations Effective June 9, 2021 - Sulfur Dioxide (SO_2) Emissions
Golden Valley Electric Association - North Pole Power Plant

Emission Unit ID	Emission Unit Description	Maximum Capacity	Fuel Type	Factor Reference	Maximum Fuel Sulfur Content	SO_2 Emission Factor	Allowable Annual Operation	Potential Emissions
Significant Emission Units								
1	Simple Cycle Gas Turbine	672 MMBtu/hr	Fuel Oil	AP-42 Table 3.1-2a	0.5 wt. pct. S [1]	0.505 lb/MMBtu	5,411 hr/yr	918.18 tpy
2	Simple Cycle Gas Turbine	672 MMBtu/hr	Fuel Oil	AP-42 Table 3.1-2a	0.5 wt. pct. S [1]	0.505 lb/MMBtu	7,992 hr/yr	1,356.08 tpy
5	Combined Cycle Gas Turbine	455 MMBtu/hr	Jet A/Diesel #1 (startup)	Mass Balance (startup)	0.3 wt. pct. S	0.041 lb/gal	1,500,000 gal/yr	30.60 tpy
			Naphtha/LSR	AP-42 Table 3.1-2a (non-startup)	0.005 wt. pct. S [2]	0.005 lb/MMBtu	8,302 hr/yr	9.54 tpy
6	Combined Cycle Gas Turbine	455 MMBtu/hr	Jet A/Diesel #1 (startup)	Mass Balance (startup)	0.3 wt. pct. S	0.041 lb/gal	1,500,000 gal/yr	30.60 tpy
			Naphtha/LSR	AP-42 Table 3.1-2a (non-startup)	0.005 wt. pct. S [2]	0.005 lb/MMBtu	8,302 hr/yr	9.54 tpy
7	Emergency Generator Engine	32.0 gal/hr [4]	No. 2 Diesel	Mass Balance	0.05 wt. pct. S [3]	0.007 lb/gal	52 hr/yr	6.1E-03 tpy
11	Boiler	5.0 MMBtu/hr	Propane	Mass Balance	1.9E-07 wt. pct. S	1.6E-08 lb/gal	8,760 hr/yr	3.8E-06 tpy
12	Boiler	5.0 MMBtu/hr	Propane	Mass Balance	1.9E-07 wt. pct. S	1.6E-08 lb/gal	8,760 hr/yr	3.8E-06 tpy
							Significant Emission Units Total Assessable Potential to Emit - SO_2	**2,354.5 tpy**
Insignificant Emission Units								
N/A	Burnham 17 A-T Boiler [6]	0.222 MMBtu/hr	Heating Oil	Mass Balance	0.5 wt. pct. S	0.073 lb/gal	8,760 hr/yr	0.51 tpy
3	Fuel Oil Storage Tank	50,000 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
4	Fuel Oil Storage Tank	50,000 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 1 Heater 1- Steel Vessel	180 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 1 Heater 2- Steel Vessel	180 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 2 Heater 1- Steel Vessel	200 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 2 Heater 2- Steel Vessel	200 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 1 Filter 1- Steel Vessel	80 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 1 Filter 2- Steel Vessel	80 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 2 Filter 1- Steel Vessel	80 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 2 Filter 2- Steel Vessel	80 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Heating Oil Storage Tank	1,000 gallons	Heating Oil	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank Filter 1- Steel Vessel	160 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank Filter 2-Steel Vessel	160 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Emergency Generator Engine Tank	2,500 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Emergency Generator Engine Day Tank	275 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
							Insignificant Emission Units Total Assessable Potential to Emit - SO_2	**0.51 tpy**
							Total Assessable Potential to Emit - SO_2	**2,355.1 tpy**

Notes:

[1] Limit fuel sulfur content of fuel deliveries to 1,000 ppmw on curtailment days effective no later than October 1, 2020.

[2] Limit fuel sulfur content to 50 ppmw (except during startup) effective no later than June 9, 2021.

[3] Limit fuel sulfur content to 0.05 weight percent sulfur effective no later than June 9, 2021.

[4] The engine specification datasheet indicates a maximum fuel throughput of 32 gal/hr.

Sample Calculations:

Molar mass ratio is 32 lb S/mol : 64 lb SO_2/mol

Stoichiometry: 1 mol S = 1 mol SO_2

Mass Balance Emission Factor, lb/gal = (Molar mass ratio, 2 lb SO_2:1 lb S) x (weight % S in fuel) x (density of fuel, lb/gal) / 100%

Turbine Emissions, tpy= (Emission factor, lb/MMBtu) x (Rating, MMBtu/hr) x (Operation, hr/yr) / (2,000 lb/ton)

Engine Emissions, tpy= (Emission factor, lb/gal) x (Capacity, gal/hr) x (Operation, hr/yr) / (2,000 lb/ton)

Boiler Emissions, tpy= (Emission factor, lb/gal) / (HHV, MMBtu/gal) x (Rating, MMBtu/hr) x (Operation, hr/yr) / (2,000 lb/ton)

Boiler wt. pct. S= (Sulfur compound content, 120 ppmv SO_2) x (Conversion, 1.66E-7 lb SO_2/scf / ppm SO_2) x (F-factor, 8,710 scf/MMBtu) x (Conversion, 0.0216 MMBtu/lb) x (Conversion, mole SO_2/64 lb SO_2) x (Conversion, mole S/mole SO_2) x (Conversion, 32 lb S/ mole S)

Engineering Data:

HHV Propane=	0.091	MMBtu/gal	(40 CFR 98 Table C-1)
HHV No. 1 Diesel=	0.139	MMBtu/gal	(40 CFR 98 Table C-1)
HHV No. 2 Diesel=	0.138	MMBtu/gal	(40 CFR 98 Table C-1)
Heat Content of Propane=	0.0216	MMBtu/lb	(https://www.engineeringtoolbox.com/heating-values-fuel-gases-d_823.html)
Jet A and No. 1 Diesel Density=	6.8	lb/gal	
No. 2 Diesel Density=	7.3	lb/gal	
Propane Density=	4.2	lb/gal	

Table B-5. Potential to Emit Calculations Effective October 1, 2023 - Sulfur Dioxide (SO_2) Emissions
Golden Valley Electric Association - North Pole Power Plant

Emission Unit ID	Emission Unit Description	Maximum Capacity	Fuel Type	Factor Reference	Maximum Fuel Sulfur Content	SO_2 Emission Factor	Allowable Annual Operation	Potential Emissions
Significant Emission Units								
1	Simple Cycle Gas Turbine	672 MMBtu/hr	April 1 - Sept 31	AP-42 Table 3.1-2a	0.5 wt. pct. S [1]	0.505 lb/MMBtu	4,392 hr/yr	745.23 tpy
			Oct 1 - March 31	AP-42 Table 3.1-2a	0.0015 wt. pct. S [2]	0.002 lb/MMBtu	1,019 hr/yr	0.52 tpy
2	Simple Cycle Gas Turbine	672 MMBtu/hr	April 1 - Sept 31	AP-42 Table 3.1-2a	0.5 wt. pct. S [1]	0.505 lb/MMBtu	4,392 hr/yr	745.23 tpy
			Oct 1 - March 31	AP-42 Table 3.1-2a	0.0015 wt. pct. S [2]	0.002 lb/MMBtu	3,600 hr/yr	1.83 tpy
5	Combined Cycle Gas Turbine	455 MMBtu/hr	Jet A/Diesel #1 (startup)	Mass Balance (startup)	0.3 wt. pct. S	0.041 lb/gal	1,500,000 gal/yr	30.60 tpy
			Naphtha/LSR	AP-42 Table 3.1-2a (non-startup)	0.005 wt. pct. S	0.005 lb/MMBtu	8,302 hr/yr	9.54 tpy
6	Combined Cycle Gas Turbine	455 MMBtu/hr	Jet A/Diesel #1 (startup)	Mass Balance (startup)	0.3 wt. pct. S	0.041 lb/gal	1,500,000 gal/yr	30.60 tpy
			Naphtha/LSR	AP-42 Table 3.1-2a (non-startup)	0.005 wt. pct. S	0.005 lb/MMBtu	8,302 hr/yr	9.54 tpy
7	Emergency Generator Engine	32.0 gal/hr [3]	No. 2 Diesel	Mass Balance	0.05 wt. pct. S	0.007 lb/gal	52 hr/yr	6.1E-03 tpy
11	Boiler	5.0 MMBtu/hr	Propane	Mass Balance	1.9E-07 wt. pct. S	1.6E-08 lb/gal	8,760 hr/yr	3.8E-06 tpy
12	Boiler	5.0 MMBtu/hr	Propane	Mass Balance	1.9E-07 wt. pct. S	1.6E-08 lb/gal	8,760 hr/yr	3.8E-06 tpy
					Significant Emission Units Total Assessable Potential to Emit - SO_2			**1,573.1 tpy**
Insignificant Emission Units								
N/A	Burnham 17 A-T Boiler [6]	0.222 MMBtu/hr	Heating Oil	Mass Balance	0.5 wt. pct. S	0.073 lb/gal	8,760 hr/yr	0.51 tpy
3	Fuel Oil Storage Tank	50,000 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
4	Fuel Oil Storage Tank	50,000 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 1 Heater 1- Steel Vessel	180 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 1 Heater 2- Steel Vessel	180 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 2 Heater 1- Steel Vessel	200 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 2 Heater 2- Steel Vessel	200 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 1 Filter 1- Steel Vessel	80 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 1 Filter 2- Steel Vessel	80 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 2 Filter 1- Steel Vessel	80 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank No. 2 Filter 2- Steel Vessel	80 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Heating Oil Storage Tank	1,000 gallons	Heating Oil	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank Filter 1- Steel Vessel	160 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank Filter 2-Steel Vessel	160 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Emergency Generator Engine Tank	2,500 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Emergency Generator Engine Day Tank	275 gallons	Diesel	Mass Balance	N/A	N/A	8,760 hr/yr	0 tpy
					Insignificant Emission Units Total Assessable Potential to Emit - SO_2			**0.51 tpy**
							Total Assessable Potential to Emit - SO_2	**1,573.6 tpy**

Notes:

[1] Limit fuel sulfur content of fuel deliveries to 1,000 ppmw on curtailment days effective no later than October 1, 2020.

[2] Limit fuel sulfur content to 15 ppmw (October 1 - March 31) effective no later than October 1, 2023. Worst case emissions are calculated.

[3] The engine specification datasheet indicates a maximum fuel throughput of 32 gal/hr.

Sample Calculations:

Molar mass ratio is 32 lb S/mol : 64 lb SO_2/mol

Stoichiometry: 1 mol S = 1 mol SO_2

Mass Balance Emission Factor, lb/gal = (Molar mass ratio, 2 lb SO_2:1 lb S) x (weight % S in fuel) x (density of fuel, lb/gal) / 100%

Turbine Emissions, tpy= (Emission factor, lb/MMBtu) x (Rating, MMBtu/hr) x (Operation, hr/yr) / (2,000 lb/ton)

Engine Emissions, tpy= (Emission factor, lb/gal) x (Capacity, gal/hr) x (Operation, hr/yr) / (2,000 lb/ton)

Boiler Emissions, tpy= (Emission factor, lb/gal) / (HHV, MMBtu/gal) x (Rating, MMBtu/hr) x (Operation, hr/yr) / (2,000 lb/ton)

Boiler wt. pct. S= (Sulfur compound content, 120 ppmv SO_2) x (Conversion, 1.66E-7 lb SO_2/scf / ppm SO_2) x (F-factor, 8,710 scf/MMBtu) x (Conversion, 0.0216 MMBtu/lb) x (Conversion, mole SO_2/64 lb SO_2) x (Conversion, mole S/mole SO_2) x (Conversion, 32 lb S/ mole S)

Engineering Data:

HHV Propane=	0.091	MMBtu/gal	(40 CFR 98 Table C-1)
HHV No. 1 Diesel=	0.139	MMBtu/gal	(40 CFR 98 Table C-1)
HHV No. 2 Diesel=	0.138	MMBtu/gal	(40 CFR 98 Table C-1)
Heat Content of Propane=	0.0216	MMBtu/lb	(https://www.engineeringtoolbox.com/heating-values-fuel-gases-d_823.html)
Jet A and No. 1 Diesel Density=	6.8	lb/gal	
No. 2 Diesel Density=	7.3	lb/gal	
Propane Density=	4.2	lb/gal	

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Attachment C

Copy of Title I Permit No. AQ0110CPT01, Revision 1

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DEPARTMENT OF ENVIRONMENTAL CONSERVATION

AIR QUALITY CONTROL CONSTRUCTION PERMIT

Permit No. AQ0110CPT01, Revision 1 Final – March 3, 2006
Revises and replaces Permit No. 110CP01

The Department of Environmental Conservation, under the authority of AS 46.14 and 18 AAC 50, issues a construction permit to the permittee, **Golden Valley Electric Association, Inc** for the **North Pole Expansion Project** at the **North Pole Power Plant** in North Pole, Alaska. The permit authorizes two new distillate-fired gas turbines, each with unfired heat recovery steam generators (HRSG), and one common steam turbine generator. In addition, the permit authorizes installation of auxiliary equipment which includes one internal combustion (IC) engine powered emergency generator, and one IC engine powered firewater booster pump as part of the **project** using Combined-Cycle Technology.

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

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

John F. Kuterbach, Manager
Air Permits Program

Table of Contents

List of Abbreviations Used in this Permit

AAC	Alaska Administrative Code
ADEC	Alaska Department of Environmental Conservation
AS	Alaska Statutes
ASTM	American Society of Testing and Materials
CFR	Code of Federal Regulations
COMS	Continuous Opacity Monitoring System
dscf	Dry standard cubic foot
EPA	US Environmental Protection Agency
gr./dscf	grain per dry standard cubic feet (1 pound = 7000 grains)
GPH	gallons per hour
HAPS	Hazardous Air Pollutants [hazardous air contaminants as defined in AS 46.14.990(14)]
HRSG	Heat Recovery Steam Generators
ID	Source Identification Number
MACT	Maximum Achievable Control Technology
Mlb	thousand pounds
NESHAPs	Federal National Emission Standards for Hazardous Air Pollutants [as defined in 40 CFR 61]
NSPS	Federal New Source Performance Standards [as defined in 40 CFR 60]
PPM	Parts per million
PS	Performance specification
PSD	Prevention of Significant Deterioration
RM	Reference Method
SIC	Standard Industrial Classification
SO_2	Sulfur dioxide
TPH	Tons per hour
TPY	Tons per year
VOC	volatile organic compound [as defined in 18 AAC 50.990(103)]
Wt%	weight percent

Section 1. Identification

Names and Addresses

Permittee:	Golden Valley Electric Association, Inc. P.O. Box 71249 Fairbanks, AK 99707-1249
Facility:	**North Pole Power Plant**
Location:	64° 44′ 04″ N latitude; 147° 20′ 43″W longitude
Physical Address:	H&H Lane North Pole, AK
Owner:	Golden Valley Electric Association, Inc. P.O. Box 71249 Fairbanks, AK 99707-1249
Operator:	Golden Valley Electric Association, Inc. P.O. Box 71249 Fairbanks, AK 99707-1249
Permittee's Responsible Official:	Ms. Kate Lamal, GVEA, Vice President Power Supply
Designated Agent:	Ms. Kate Lamal, GVEA, Vice President Power Supply Golden Valley Electric Association, Inc. P.O. Box 71249 Fairbanks, AK 99707-1249
Facility and Building Contact:	Mr. Alexander Gajdos Golden Valley Electric Association, Inc. H&H Lane, North Pole, AK (907) 488-9264 or (907) 488-9265 or (907) 451-5624
Fee Contact:	Mr. Henrik Wessel Golden Valley Electric Association, Inc. P.O Box 71249, Fairbanks, AK 99707-1249 Phone: (907) 451 – 5627 e-mail: hw@gvea.com
Facility Process Description	Electric Services. Engaged in the generation, transmission, and/or distribution of electric energy for sale.
SIC Code of the Facility:	4911

Section 2. Permit Continuity

Condition 1. Except as revised or rescinded herein or as superseded by an Air Quality Permit issued under AS 46.14.170, the permittee shall comply with terms and Conditions of Air Quality Control Operating Permit No. 110TVP01.

Condition 2. If permit terms and conditions listed in this permit conflict with those of Operating Permit No. 110TVP01, the permittee shall comply with terms and conditions listed herein.

Section 3. Emission Information and Classification

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

a. Particulate Matter (PM-10), Sulfur Oxides (SO_X), Nitrogen Oxides (NO_X), Carbon Monoxide (CO), and Volatile Organic Compounds (VOC).

Facility Classifications as described under 18 AAC 50.300(b) through (g), modifications as described under 18 AAC 50.300(h), or owner requested limit classification under 18 AAC 50.305(a)(1) through (4):

a. The North Pole Power Plant Combined-Cycle project requires construction permit provisions requested by the owner or operator under 18 AAC 50.305(a)(3) and (a)(4).

b. North Pole Power Plant is classified as a Prevention of Significant Deterioration (PSD) Major Facility as defined; 18 AAC 50.300(c)(1) because it has the potential to emit more than 250 tons per year of a regulated air contaminant in an area classified as attainment or unclassifiable. The plant will be classified as PSD Major as defined in 18 AAC 50.300(c)(2)(A) because it has the potential to emit more than 100 tons per year of a regulated air contaminant in an area designated attainment or unclassifiable and will become a fossil-fuel-fired steam electric plant of more than 250 MMBtu/hr.

c. This project is classified as a modification requiring a construction permit under 18 AAC 50.300(h)(2) because it has potential to increase actual emissions of an air contaminant for which an ambient air quality standard is established.

d. The permittee has requested limits to avoid the project's classification as a PSD significant modification under 18 AAC 50.300(h)(3) as provided by 18 AAC 50.305(a)(4).

Section 4. Source Inventory and Description

Sources listed in Table 1 have specific monitoring, recordkeeping, or reporting conditions in this permit. Source descriptions and ratings are given for identification purposes only. The total facility equipment inventory can be seen in North Pole Power Plant's Title V Permit No. AQ0110TVP01. The numbering in Table 1 is consistent with the Operating Permit No. AQ0110TVP01.

Table 1. Source Inventory

ID	Source Name	Year Installed	Rating/Size
5*	GT#3, General Electric Gas Turbine Generators, model LM6000PC (with water injection for NO_X control and CO oxidation catalyst)	2005	455 MMBtu/hr (HHV) 43 MW (Nominal)
6*	GT#4, General Electric Gas Turbine Generators, model LM6000PC (with water injection for NO_X control and CO oxidation catalyst)	2006	455 MMBtu/hr (HHV) 43 MW (Nominal)
7	IC Engine, Emergency Generator	2005	400 kW
11	Bryan Steam RV500 Heater with Gordon-Piatt R10.2-G-50	2004	4.5 MMBtu/hr
12	Bryan Steam RV500 Heater with Gordon-Piatt R10.2-G-50	2004	4.5 MMBtu/hr

*Source ID 1, 672 MMBtu/hr (60.5 MW) GE Frame 7, Series 7001, Fuel Oil-fired Model BR regenerative gas turbine, found in Operating Permit 110TVP01, will offset emissions from Source IDs 5 and 6.

Condition 3. This Permit authorizes the new sources installation as listed in Table 1.

Condition 4. For Sources IDs 7, 11, and 12, the permittee shall submit within 30 days after installation, a copy of the vendor specification sheets listing the duty rating, fuel type, fuel consumption, serial number and fuel control settings.

Section 5. Ambient Air Quality

Condition 5. Use only diesel fuel with a total sulfur content of no more than 0.1 % by weight in Source ID 7

5.1 Obtain a statement or receipt from the fuel supplier for each fuel shipment, certifying the fuel sulfur content.

5.2 Report in the Excess Emission and Permit Deviation Report as required by Section 10 of Operating Permit No. 110TVP01 whenever the sulfur content of the fuel exceeds the 0.1 percent

5.3 Record the total sulfur content of the diesel fuel required under Condition 5.1.

Condition 6. Limit the individual hours of operation for Source ID 7 to 52 hours per year calculated on a 12-month rolling average period.

6.1 Monitor and record the cumulative total monthly hours of operation for Source ID 7. Calculate and record the cumulative 12-month rolling total hours of operation for the unit.

6.2 Report in the Operating Report as required by Section 11 of the Operating Permit No. 110TVP01 the cumulative monthly and 12- month rolling total hours of operation for Source ID 7.

Condition 7. Use only gas fuel (propane) for Source IDs 11 and 12 with a total sulfur content of no more than 120 ppm by volume.

7.1 Obtain a statement or receipt from the fuel supplier for each gas fuel shipment, certifying the gas fuel sulfur concentration in ppm by volume. If a certificate is not available from the supplier, then analyze a representative sample of the fuel shipment to determine the sulfur content using 40 CF.R 60, Appendix A Method 11 or an alternative method approved by the department.

7.2 Report in the Excess Emission and Permit Deviation Report condition required by Section 10 of Operating Permit No. 110TVP01 whenever the sulfur content exceeds the 120 ppm concentration by volume.

7.3 Record the sulfur content of the gas fuel required under Condition 7.1

Section 6. State Emission Standards

Industrial Processes and Fuel Burning Equipment

Visible Emissions

Condition 8. The permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from Source IDs 5, 6, 7, 11, and 12 listed in Table 1 to reduce visibility through the exhaust effluent by any of the following:

a. greater than 20 percent for more than three minutes in any one hour[1],

[18 AAC 50.055(a)(1), 1/18/97, 40 CFR 52.70, 11/18/97]

b. greater than 20 percent averaged over any six consecutive minutes.

[18 AAC 50.055(a)(1), 18 AAC 50.346(c), 05/03/002]
[18 AAC 50.320(a)(2), 1/18/97]

8.2 Monitor, record, and report visible emissions for Source IDs 5, 6, 7, 11 and 12 in accordance with Conditions 49-51 in Operating Permit No. 110TVP01. Conduct an initial visible emission reading after start of operations of Source IDs 5, 6, 7, 8, 11 and 12 within 30 days after initial startup of each unit.

[18 AAC 50.040(a)(2), 7/1/99]
[18 AAC 50.055(a)(1), 1/18/97]
[18 AAC 50.320(a)(2)(A-E), 1/18/97]

Particulate Matter

Condition 9. The permittee shall not cause or allow particulate matter emitted from Source IDs 5, 6, and 7 to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours. Monitor, record, and report according to Conditions 52-55 of the Operating Permit No. 110TVP01.

[18 AAC 50.055(b)(1), 1/18/97]
[18 AAC 50.350(d), 6/21/98]
[18 AAC 50.320(a)(2), 1/18/97]

Sulfur Compound Emissions

Condition 10. The permittee shall not cause or allow sulfur compound emissions, expressed as SO_2, to exceed 500 PPM averaged over three hours.

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[1] For purposes of this permit, the "more than three minutes in any one hour" criterion in this Condition will no longer be effective when U.S.EPA. incorporates the Air Quality Control (18 AAC 50) regulation package effective 5/3/02 into the Alaska State Implementation Plan.

Ice Fog Standard

Condition 11. The department will, in its discretion, require a person who proposes to build or operate an industrial process, fuel-burning equipment, or incinerator in an area of potential ice fog to obtain a permit and to reduce water emissions. Monitor, record, and report ice fog conditions in accordance with Condition 14.4b(ii)

[18 AAC 50.080, 1/18/97]

Insignificant Emission Sources

Condition 12. Section 7 of Operating Permit No. 110TVP01 contains the requirements the Permittee must identify under 18 AAC 50.335(q)(2) as applicable to insignificant sources at the facility. This section also specifies the testing, monitoring, reporting, and recordkeeping for insignificant sources that the Department finds necessary to ensure compliance with the applicable requirements. Insignificant sources are not exempted from any air quality control requirement or federally enforceable requirement.

Section 7. Federal Emission Standards

Comply with the requirements of 40 CFR 60, New Source Performance Standards (NSPS) as they apply to affected facilities specified below. Notify and report as set out below and as specified in Condition 22.

General Provisions Subject to NSPS Subpart A

Condition 13. **40 CFR 60, Subpart A, General Provisions.** For Source IDs 5 and 6. In accordance with 40 CFR 60, Subpart A and 18 AAC 50.040, for each construction, modification, or reconstruction of affected facilities and sources regulated under 40 CFR 60

13.1 Notify the department and EPA:

a. No later than 30 days after construction or reconstruction commencement in accordance with 40 CFR 60.7(a)(1);

b. No more than 15 days after startup in accordance with 40 CFR 60.7(a)(3);

c. 60 days prior or as soon as practicable before modifying facilities that would be subject to NSPS as set out in 40 CFR 60.7(a)(4);

d. No less than 30 days prior to conducting a demonstration of continuous monitoring system performance as set out in 40 CFR 60.7(a)(5);

e. No less than 60 days prior to commencement of reconstruction or replacement of a facility, as defined in 40 CFR 60, notify the department and EPA with information as set out in 40 CFR 60.15(d).

[18 AAC 50.320(a)(2)(A-E), 1/18/97]
[18 AAC 50.040(a)(1), 1/18/97]

13.2 Maintain records of occurrence and duration of startup, shutdown, or malfunction of an affected facility, control equipment, or monitoring equipment as set out in 40 CFR 60.7(b). Submit continuous monitoring system performance reports as set out in 40 CFR 60.7(c) and (d). Maintain a file of measurements as set out in 40 CFR 60.7(e).

[18 AAC 50.320(a)(2)(A-E), 1/18/97]
[18 AAC 50.040(a)(1), 1/18/97]

13.3 Within 60 days after each source achieves maximum production rate, but no later than 180 days after initial start-up and at such other times as may be required by the EPA under Section 114 of the U.S. Clean Air Act, conduct performance tests as follows:

a. Notify the department and EPA at least 30 days in advance of any performance test and opacity observation as set out in 40 CFR 60.8(d) and 60.11(e)(1);

b. Conduct performance tests and data reduction as set out in 40 CFR 60.8(b) and (f);

c. Provide the department copies of EPA administrator approvals for alternative performance testing;

d. Provide sampling ports and safe sampling platform(s), safe access to platform(s), and utilities, and conduct testing as set out under 40 CFR 60.8(c) and (e); and

e. Furnish the department and EPA a written report of the performance test and opacity observation results as set out in 40 CFR 60.8(a) and 60.11(e)(2) through (5).

[18 AAC 50.320(a)(2)(A-E), 1/18/97]
[18 AAC 50.040(a)(1), 1/18/97]

13.4 **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 affected facilities including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the department that may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance records, and inspections of affected facilities.

[18 AAC 50.320(a)(2)(A-E), 1/18/97]
[18 AAC 50.040(a)(1), 1/18/97]

13.5 The permittee is prohibited from concealing a violation of any applicable NSPS standard as set out in 40 CFR 60.12.

[18 AAC 50.320(a)(2)(A-E), 1/18/97]
[18 AAC 50.040(a)(1), 1/18/97]

13.6 Performance tests shall be conducted and data reduced in accordance with test methods and procedures contained in the applicable NSPS subpart; unless the department and EPA approve the use of an equivalent method or approve the use of an alternative method which has been determined adequate for indicating compliance with the NSPS standard:

a. Ensure all systems and devices used to monitor and record the NO_X and oxygen emissions are installed, calibrated, and operational no later than 60 days after startup and as set out in 40 CFR 60.13(b) prior to conducting a performance test under 40 CFR 60.8;

b. Ensure all systems and devices used to monitor and record the NO_X and oxygen emissions meet the minimum frequency of operation requirements set out in 40 CFR 60.13(e), and are kept in continuous operation, except for system breakdowns, repairs, calibration checks, and zero/span adjustments;

c. Ensure all systems and devices used to monitor and record the NO_X and oxygen emissions obtain representative measurement of emissions or process parameters as set out in 40 CFR 60.13(f);

d. Ensure all systems and devices used to monitor and record the NO_X and oxygen emissions are able to reduce all data to 3-hour average nitrogen oxide concentration measurements; and

e. Provide the department a copy of each EPA alternative monitoring approval or relative accuracy test audit (RATA) approval issued under 40 CFR 60.13(i) or (j) within 30 days of receipt.

[18 AAC 50.320(a)(2)(A-E), 1/18/97]
{18 AAC 50.040(a)(1), 1/18/97}

13.7 For the purpose of submitting compliance certifications or establishing whether or not the permittee has violated or is in violation of any standard cited in this part, nothing in this part shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether the NSPS-affected sources would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

Stationary Gas Turbines Subject to NSPS Subpart GG

Condition 14. **40 CFR 60, Subpart GG.** The requirements of Condition 14 apply only to Turbine Source IDs 5 and 6: 43 MW GE, Model LM 6000 combustion turbine burning gas turbine fuels, 0-GT and 1-GT (naphtha/LSR and Jet A), with a heat input rating of no greater than 455 MMBtu/hr (HHV) input.[2]

14.1 Applicability and designation of affected facilities, 40 CFR 60.330. Affected sources are stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 MMBtu/hr) based on lower heating value as described in 40 CFR 60.330(a) and (b).

[2] Permit conditions that may have been modified to indicate the permittee's expected operation following EPA approvals for alternative schedules and performance testing but does not relieve the permittee from the actual requirements listed in Subpart GG.

14.2 Standard for nitrogen oxides, 40 CFR 60.332(a)(1). Comply with the NO_X emission limitation as listed in 40 CFR 60.332(a)(1). The limit is STD = 0.0075(14.4)/Y + F; where STD is the allowable NO_X emissions (percent by volume) at 15% O_2, at ISO conditions. Y is the manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour), or actual heat rate based on lower heating value of fuel measured at actual peak load during performance test, and F is the emission allowance for fuel-bound nitrogen, no credit for fuel bound nitrogen is being used. Based on the manufacturer's rated heat rate of 7.42 kJ/Watt-hour, the standard for Source IDs 5 or 6 is 146 ppmv at 15% O_2 and ISO conditions.

a. Manufacturers may develop custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the EPA before the initial performance test required by Condition 13.3b.

b. If using water to control NO_X emission, the turbine unit is exempt from the NO_X limitation in Condition 14.2 when the owner or operator of the unit discontinues water injection because the ice fog is a traffic hazard.

14.3 Standard for sulfur dioxide, 40 CFR 60.333. Comply with the sulfur dioxide exhaust concentration for new source performance listed in 40 CFR 60.333(a) or (b) of 150 ppm by volume at 15 percent oxygen and on a dry basis or 0.8% fuel sulfur content by weight, respectively.

14.4 Monitoring of operations, 40 CFR 60.334.

a. Comply with 40 CFR 60.334(b) to monitor the nitrogen and sulfur content of the distillate fuel. Determine and record distillate fuel nitrogen and sulfur content daily. Owner, operators, or fuel vendors may develop custom schedules to test fuel as specified in 40 CFR 60.334(b)(2) substantiated with data and approved by the EPA before using the custom schedule.

b. Include with excess emission and monitoring system reports submitted under 40 CFR 60.7(c), information as listed in:

(i) 40 CFR 60.334(c)(2)—any daily period for which fuel sulfur content fired in the turbine exceeds 0.8% by weight; and

(ii) 40 CFR 60.334(c)(3)—Report in writing to the department and EPA during calendar quarters for which the owner or operator deems that ice fog is a traffic hazard. Report for each period the ambient conditions existing during that period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated. Postmark the quarterly report by the 30^{th} day following the end of each calendar quarter.

14.5 Test methods and procedures, 40 CFR 60.335.

a. To compute the nitrogen oxide emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 percent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

b. When conducting performance tests for nitrogen oxide emissions as required in 40 CFR 60.335(b) and (c), or alternative test methods in accordance with 40 CFR 60.335(f):

(i) Compute the NO_X emission rate for each run using the equation listed in 60.335(c)(1).

(ii) Use the continuous emission monitoring (CEM) system to measure compliance with the NO_X emission standard at:

30%, 50%, 75%, and 100% of peak load, or

at four points in the normal operating range of each turbine, including the minimum load in the range, and peak load.

(iii) Use Method 20 to determine NO_X and O_2 concentrations. Use a span value of 300-ppm nitrogen oxide and 21 percent oxygen. Determine NO_X emissions at each of the four load conditions tested.

(iv) Use the continuous NO_X and O_2 emission monitoring system required by Condition 14.4 and Condition 19 to ensure compliance with the NO_X standard set out in Condition 14.2. Correct the measured NO_X concentration to 15% O_2 exhaust concentration based on the equations in 40 CFR 60 Appendix A, Method 20. Continuously monitor and record compliance with the turbine NO_X concentration limit set out in Condition 14.2 based upon 3-hour average nitrogen oxide concentration measurement.

c. Determine compliance with the sulfur content standard using methodology as described in 40 CFR 60.335(d); unless the department and EPA approves the use of an equivalent method or approves the use of an alternative method which has been determined adequate for indicating compliance with the standard.

(i) Use the sulfur analysis methods incorporated by reference in ASTM D 2880-71, 78, or 96.

(ii) Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the Federal Administrator's approval.

d. The permittee may propose an alternative ambient correction factor to the equation in 40 CFR 60.335(c)(1), in accordance with 40 CFR 60.335(f)(1), to adjust the nitrogen oxide emission level measured by the performance test as provided in 40 CFR 60.8. Substantiate the alternative with data and obtain Federal Administrator approval before using the alternative. Submit a copy of the approved correction factor to the department within 30 days after the EPA approval. Keep a copy of each EPA issued alternative monitoring method with the permit at the facility.

[18 AAC 50.040(a), 1/18/97] {Federal Citation 40 C.F.R. 60.11(d)}

Volatile Organic Liquid Storage Vessels (Tanks) Subject to NSPS Subpart Kb

Condition 15. <rescinded>

Section 8. Owner Requested Limits to Avoid Classification as a PSD Major Modification

Nitrogen Oxides, Carbon Monoxide and Sulfur Dioxides Requirements. The permittee shall avoid classification as a Prevention of Significant Deterioration major modification under 18 AAC 50.300(h)(3)(B)(ii) for NO_X; 18 AAC 50.300(h)(3)(B)(i) for CO; 18 AAC 50.300(h)(3)(B)(iii) for SO_2 as follows:

Condition 16. Limit NO_X Emissions expressed as NO_2.

16.1 Source ID 2 (GT#2), limits found in the Operating Permit No. 110TVP01 issued August 27, 2002, remains at 7,992 hours on a continuous, 12-month rolling period. Additional limits of operation for Source IDs 1, 5 and 6 are as follows:

a. Limit the cumulative annual NO_X emissions to 1600 tons/year (tpy) using a 12-month rolling averaging period for Source IDs 1, 5 and 6, initialized upon startup of Source ID 5.

b. On initial startup of Source ID 5, limit and initialize annual NO_X emissions from Source ID 1 (GT#1). Source ID 1 emissions reductions offset the emissions increases from Source IDs 5 and 6 to maintain compliance with Condition 16.1a.

c. Limit continuous emission of NO_X to comply with Condition 16.1a by installing and operating water injection on Source IDs 5 and 6 except during ice-fog events as provided in Condition 14.2b.

d. Permittee will notify the department as directed in Section 10 of Operating Permit No. 110TVP01 if Source ID 2 (GT#2) will be out of service more than 30 days due to a failure, or a breakdown. In such an event, the permittee will commission Source ID 1 (GT#1) in lieu of Source ID 2 for the outage period. Source ID 1 emissions during the outage period will not be counted toward the Source ID 1's 12-month rolling averaging NO_X limit. Permittee will notify the department when Source ID 2 resumes operation and Source ID 1 returns to operation under the rolling annual NO_X emission cap.

e. Report Source ID 1 hours of operation as Source ID 2 hours of operation when substituting for Source ID 2 hours of operation in the Operating Report. When substituted for Source ID 2 hours of operation Source ID 1 emissions are not counted against the Source ID 1 NO_X limit as set out in Condition 16.1a.

16.2 Continuous NO_X Emissions Monitoring and Recordkeeping

a. Install, calibrate, certify, operate, and maintain in accordance with Condition 13.6 and Condition 20, extractive continuous NO_X and oxygen emission monitoring systems (CEMS) on Source IDs 1, 5, and 6. Source ID 1 is approved to have an alternative calibration drift and relative accuracy tests in accordance with Condition 21. Install a NO_X and oxygen CEMS sampling probe in each turbine exhaust stack on Source IDs 5 and 6. Continuously monitor and record Source IDs 1, 5, and 6 for compliance with Condition 16.1a based upon 3-hour block average nitrogen oxides and oxygen concentration measurements, convert to emission rates as set out in Condition 16.2d.

b. Either continuously monitor and record

(i) The quantity of distillate fuel burned in each of Source IDs 1, 5 and 6.

Or

(ii) Estimate for each day, the operating time, fuel consumption from any of Source IDs 1, 5 and 6 by multiplying the operating time by the design fuel consumption rate of that source.

c. For CEMS, determine or provide vendor data documenting the gross calorific value of each fuel burned.

d. Calculate the daily-average NO_X emission rate, expressed as NO_2, for Source IDs 1, 5 and 6 exhaust stack(s) based on the methodology set out in 40 CFR 60, Appendix A, Method 20, Part 7.5.1 as follows:

$$E = [C_d F_d 20.9]/[20.9 - O_{2dry}] \qquad \text{Eqn. 20-6}$$

Where:

E = NO_X Emission Rate in ng/J (lb/MMBtu)
C_d = Concentration of dry NO_X in ng/scm (lb/scf)
F_d = Fuel Factor of applicable fuel based on a dry basis, scm/J (scf/MMBtu) from Appendix A, Method 19
O_2 = Percent Oxygen on a dry basis, %

The pollutant concentration must be in ng/scm (lb/scf) and the fuel factor (F) must be in scm/J (scf/million Btu). If the pollutant concentration (C) is not in the appropriate units, use Method 19, Table 19-1 in Section 17.0 to make the proper conversion. The fuel factor is the ratio of the gas volume of the products of combustion to the heat content of the fuel. The dry fuel factor (F_d) includes all components of combustion less water. Use fuel factors for the fuel as provided for in

40 CFR 60, Appendix A, Method 19, Table 19-2 or calculate the fuel F-factor using the procedures listed in 40 CFR 60 Appendix A, Method 19, Part 12.3.2.1, Eqn. 19-13.

e. Calculate and record the total NO_X emissions, expressed as NO_2, for Source IDs 1, 5, and 6 for each monthly total and 12-month rolling averaging period by summing the total daily-average NO_X emissions from each of the turbines.

16.3 Alternative NO_X Emissions Monitoring and Recordkeeping

a. For each of Source IDs 1, 5, and 6, the permittee may develop and submit for department approval a parametric monitoring program with quality assurance procedures to predict NO_X emissions when CEMS is out-of-service or emission data are out-of-bounds with quality assurance procedures. If electing to submit the program for approval, provide a copy of all assumptions, process, emission, and ambient data analyzed in support of the program and statistical analysis for relationships between parameters and emission rates.

b. For any of Source IDs 1, 5 and 6, when the CEMS is out of service or emission data are out-of-bounds with quality assurance procedures, use the following approaches to estimate NO_X emissions. Monitor the source's operating hours when CEMS is out of service/out-of-bounds. Estimate NO_X emissions using the hours of operation and design emission rate as follows and count the estimated NO_X emissions as part of Condition 16.2 d-e:

(i) For any of Source IDs 1, 5, or 6, the permittee may use a department approved predictive monitoring relationship as set out in Condition 16.3a by monitoring relevant process, ambient parameters and operating hours and calculating emission rates; or

(ii) For Source IDs 5 or 6, assume a NO_X design emission rate of 114 lb/hr for operations when the water to fuel injection ratio equal to or greater than 1.0. If the maximum hourly emission rate for Source ID 5 or 6 during the most recent 30 operating days exceeds 114 lb/hr then use the maximum hourly emission rate during the most recent 30 operating days for which calibration monitoring records were collected; or the permittee may use the fuel consumption and the water to fuel ratio data collected in Condition 14.4 to determine the NO_X concentration in accordance with Condition 14.5;

(iii) For Source IDs 5 and 6 assume an unabated NO_X design emission rate of 685 lb/hr when water to fuel injection ratio is less than 1.0.

(iv) For Source ID 1, assume a NO_X design emission rate of 824 lb/hr. If the maximum emission rate for Source ID 1 during the most recent 30 days exceeds 824 lb/hour then use the maximum hourly emission rate during the most recent 30 operating days for which calibrated monitoring records were collected.

c. For Source ID 1 record the time, date and duration that Source ID 1 operates in lieu of Source ID 2 during an outage as described in Condition16.1d.

16.4 Reporting--Report in the Operating Report as required by Section 10 of the Operating Permit No. 110TVP01.

a. the monthly total NO_X emissions and 12-month rolling average of NO_X emissions from each exhaust stack of Source IDs 1, 5, and 6.

b. the time, date, and duration for which Source ID 1 operated in lieu of Source ID 2 during an outage described in Condition 16.1d.

Condition 17. Limit Sulfur Dioxide Emissions, expressed as SO_2

17.1 Limit the sulfur fuels as follows:

a. Limit the sulfur content in gas turbine fuel 0-GT (naphtha or LSR) burned in Sources IDs 5 and 6 to no more than 0.05 percent by weight.

b. Limit the sulfur content in gas turbine fuel 1-GT (JetA) used for startup in Source IDs 5 and 6 to no more than 0.30 percent by weight; and

c. Limit the volume of gas turbine fuel 1-GT consumed in Source IDs 5 and 6 to no more than 1.5 million gallons per year.

17.2 Follow fuel sulfur measurement and certification procedures contained in Condition 6 of the Operating Permit No. 110TVP01. Monitor and record the fuel consumption of Source IDs 5 and 6 to assure compliance with Condition 17.1c

[18 AAC 50.055(c), 1/18/97]
[18 AAC 50.320(a)(2)(A-E), 1/18/97]

17.3 Keep records of the statements of certification, and all test results and calculations required under Conditions 17.1a-17.1c. Attach copies of the records with the Operating Report required by Section 10 in Operating Permit No. 110TVP01.

Condition 18. Limit Carbon Monoxide Emissions, expressed as CO

18.1 Limits on Source ID 2 (GT#2) limits in Operating Permit No. 110TVP01 remains at 7,992 hours on a continuous, 12- month rolling period. Additional limits of operation for Source IDs 1, 5 and 6 are as follows:

a. Limit the annual CO emissions for Source IDs 1, 5 and 6 to 115 tons/year (tpy) using a 12-month rolling averaging period. Initialized upon startup of Source ID 5.

b. Limit the combined CO emissions in the exhaust of Source IDs 5 and 6 to no greater than 98 tons per 12-month rolling averaging period, initialized upon startup of Source ID 5.

c. Limit continuous CO emissions on Source IDs 5 and 6 by installing an oxidation catalyst on each turbine's exhaust outlet upstream of the exhaust stack network.

d. Permittee will notify the department as directed in Section 11 of the Operating Permit No. 110TVP01 if Source ID 2 (GT#2) will be out of service more than 30 days due to a failure, or a breakdown. In such an event, the permittee will commission Source ID 1 (GT#1) in lieu of Source ID 2 for the outage period. Source ID 1 emissions during the outage period will not be counted toward the Source ID 1's 12-month rolling averaging CO limit. Permittee will notify the department when Source ID 2 resumes operation and Source ID 1 returns to operation under the rolling annual CO emission cap.

e. Report Source ID 1 hours of operation as Source ID 2 hours of operation when substituting for Source ID 2 hours of operation in the Operating Report. When substituted for Source ID 2 hours of operation Source ID 1 emissions are not counted against the Source ID 1 CO limit as set out in Condition 18.1a and 18.1b.

18.2 Continuous CO Emissions Monitoring and Recordkeeping

a. Install, calibrate, certify, operate, and maintain in accordance with Condition 13.6 and Condition 20, an extractive continuous CO CEMS. Source ID 1 is approved to have an alternative calibration drift and relative accuracy tests in accordance with Condition 21. Install a CO CEMS sampling probe in each turbine stack on Source IDs 1, 5, and 6. Continuously monitor and record Source IDs 1, 5, and 6 for compliance with Condition 18 based upon 3-hour block average CO measurements and oxygen measurements from Condition 18.1 (a-b), converted to emission rates as set out in Condition 18.2d.

b. Monitor as provided for in Conditions 16.2b and 16.2c

c. Monitor performance of oxidation catalyst to maintain compliance with Condition 18.1 (a-b). Perform necessary maintenance or replacement of catalyst following vendor guidelines to ensure compliance with the CO limits.

d. Calculate the daily-average CO emission rate, for Source IDs 1, 5 and 6 exhaust stack(s) based on the methodology set out in 40 CFR 60, Appendix A, Method 20, Part 7.5.1 as follows:

$$E = [C_d F_d 20.9]/[20.9 - O_{2dry}] \qquad \text{Eqn. 20-6}$$

Where:

E = CO Emission Rate in ng/J (lb/MMBtu)
C_d = Concentration of dry CO in ng/scm (lb/scf)
F_d = Fuel Factor of applicable fuel based on a dry basis, scm/J (scf/MMBtu) from Appendix A, Method 19
O_2 = Percent Oxygen on a dry basis, %

The pollutant concentration must be in ng/scm (lb/scf) and the fuel factor (F) must be in scm/J (scf/million Btu). If the pollutant concentration (C) is not in the appropriate units, use Method 19, Table 19-1 in Section 17.0 to make the proper conversion. The fuel factor is the ratio of the gas volume of the products of combustion to the heat content of the fuel. The dry fuel factor (F_d) includes all components of combustion less water. Use fuel factors for the fuel as provided for in 40 CFR 60, Appendix A, Method 19, Table 19-2 or calculate the fuel F-factor using the procedures listed in 40 CFR 60 Appendix A, Method 19, Part 12.3.2.1, Eqn. 19-13.

e. Calculate and record the total CO emissions, for Source IDs 1, 5, and 6 for each monthly total and 12-month rolling averaging period by summing the total daily-average CO emissions from each of the turbines.

18.3 Alternative CO Emissions Monitoring and Recordkeeping

a. For each of Source IDs 1, 5, and 6, the permittee may develop and submit for department approval a parametric monitoring program to predict CO emissions when CEMS are out-of-service or emission data are out-of-bounds with quality assurance procedures. If electing to submit the program for approval, provide a copy of all assumptions, process, emission, and ambient data analyzed in support of the program and statistical analysis for relationships between parameters and emissions.

b. For any of Source IDs 1, 5, and 6, when the CEMS is out of service or emission data are out-of-bounds with quality assurance procedures, use the following approaches to estimate CO emissions. Monitor the source's operating hours when the CEMS is out of service/out-of-bounds. Estimate CO emissions using the hours of operation and design emission rate as follows and count the estimated CO emissions as part of Condition 18.2 c-d:

(i) For any of Source IDs 1, 5, or 6, the permittee may use a department approved predictive monitoring relationship as set out in Condition 18.3a by monitoring relevant process, operating hours, and ambient parameters and calculating emissions; or

(ii) For each Source ID 5 and 6, assume a CO design emission rate of 11 lb/hr. If the maximum hourly emission rate during the most recent 30 operating days exceeds the 11 lb/hr then use the maximum hourly emission rate during the most recent 30 operating days for which calibrated monitoring records were collected; or the permittee may use the fuel consumption and the water to fuel ratio data collected in Condition 14.4 to determine the CO concentration in accordance with Condition 14.5; and

(iii) For Source ID 1, assume a CO design emission rate of 13.3 lb/hour when burning HAGO fuel. Or, if the maximum hourly monitored CO emission rate for Source ID 1 exceeds 13.3 lb/hr during the most recent 30 operating days, for which calibrated monitoring records were collected exceeds the design emission rate, then use that maximum hourly monitored emission rate.

c. For Source ID 1 record the time, date and duration that Source ID 1 operates in lieu of Source ID 2 during an outage described in Condition 16.1d.

18.4 Report in the Operating Report as required by Section 10 of Operating Permit No. 110TVP01, the monthly total CO emissions 12-month rolling average CO emissions from each exhaust stack of Source IDs 1, 5 and 6.

Section 9. General Source Testing and Monitoring Requirements

Condition 19. **Reference Test Methods.** The permittee shall use the following as reference test methods when conducting source testing for compliance with this permit:

19.1 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 50.220(b) & (c), 1/18/97]
[18 AAC 50.320(a)(2)(A-C), 1/18/97]

19.2 Source testing for the reduction in visibility through the exhaust effluent must be conducted in accordance with the procedures set out in Section 13 of the Operating Permit No. 110TVP01.

[18 AAC 50.220(b) & (c), 1/18/97]
[18 AAC 50.320(a)(2)(A-C), 1/18/97]

19.3 Source testing for emissions of particulate matter, nitrogen compounds, carbon monoxide, and volatile organic compounds must be conducted in accordance with the methods and procedures specified 40 CFR 60, Appendix A.

[18 AAC 50.220(b) & (c), 1/18/97]
[18 AAC 50.320(a)(2)(A-C), 1/18/97]

19.4 Source testing for emissions of PM-10 must be conducted in accordance with the procedures specified in 40 CFR 51, Appendix M.

[18 AAC 50.220(b) & (c), 1/18/97]
[18 AAC 50.320(a)(2)(A-C), 1/18/97]

19.5 Source testing for emissions of any contaminant may be determined using an alternative method approved by the department in accordance with Method 301 in Appendix A to 40 CFR 63.

[18 AAC 50.220(b) & (c), 1/18/97]
[18 AAC 50.320(a)(2)(A-C), 1/18/97]
[18 AAC 50.320(a)(2), 1/18/97]
[18 AAC 50.335(g), 1/18/97]

Condition 20. Install; calibrate; conduct applicable continuous monitoring system performance tests listed in 40 CFR 60, Appendix B, and certify test results; operate; and maintain air contaminant emissions and process monitoring equipment on the sources as described herein and in documents provided by the permittee, listed in Section 12. For Source IDs 1 and 5 submit monitoring equipment siting, operation, and maintenance plans for approval by the department 60 days prior to startup of Source IDs 5. For Source ID 6, submit monitoring equipment siting, operation, and maintenance plans for approval by the department 60 days prior to startup of Source ID 6.

For continuous emission monitoring systems comply with each applicable monitoring system requirement, as listed in 40 CFR 60.13, 60.19, the applicable subpart of 40 CFR 60 as incorporated by reference in Section 7 of this permit; 40 CFR 60, Appendix F, *Quality Assurance Procedures*; and the *EPA Quality Assurance Handbook For Air Pollution Measurements*, EPA/600 R-94/038b, effective July 1, 1997. Attach to the Facility Operating Report required in Section 10 of the Operating Permit 110TVP01, a copy of each continuous emission monitoring system data assessment report for Quality Assurance Procedures conducted in accordance with 40 CFR 60, Appendix F and the approved continuous emissions monitoring system plan approved by the department.

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

Condition 21. The permittee may request approval of an alternative test plan for Source ID 1 in accordance with 40 CFR 60, Appendix B Performance Specification 2, Section 16.0 *Alternative Procedures*, to define the frequency of testing for calibration drift and relative accuracy for times when Source ID 1 is out of service. As approved, Source ID 1 is a limited use peaking unit, turbine generator. GVEA does not have to do conduct daily CEM calibration drift tests and relative accuracy tests when Source ID 1 is not in operation. If Source ID 1 is in operation at any time during the calendar quarter, the permittee shall resume daily CEM calibration drift tests and perform a relative accuracy test on the CEM prior to unit operations. Ensure that all components of the CEMS on Source ID 1 are functioning properly before proceeding to the alternative calibration drift and relative accuracy testing procedure. Submit an alternative test plan procedure to the department 60 days prior to startup of Source ID 5 and prior to commissioning of the CEMS on Source ID 1. Included with the alternative test plan procedure detailed quality control and quality assurance procedures for emissions measurement on Source ID 1 when in service. Include the necessary actions to ensure a reliable startup of the emissions measurement systems when Source ID 1 is re-commissioned.

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

Section 10. General Recordkeeping, Reporting, and Compliance Certification Requirements

Condition 22. **NSPS and NESHAP Reports.** The permittee shall submit to the department copies of reports required by Section 6 of this permit as they apply to the facility as follows:

22.1 Attach a copy of each NSPS report submitted to the U.S. Environmental Protection Agency (EPA) Region 10 to the Operating Report required by Section 10 of the Operating Permit 110TVP01.

22.2 Notify the department of any EPA granted waivers of NSPS emission standards, recordkeeping, monitoring, performance testing, or reporting requirements within 30 days after receipt.

[18 AAC 50.040, 1/18/97]
[Federal Citation 40 CFR 60 & 40 CFR 61, 7/1/97]

Section 11. Standard Conditions Not Otherwise Included in the Permit

Condition 23. The permittee must comply with Condition 38 through 40 , Section 10, " *General Recordkeeping, Reporting, and Compliance Certification requirements*" and Condition 41 through 47 found in Section 11 "*Standard Conditions Not Otherwise Included in the Permit*" of the Operating Permit No. 110TVP01.

Section 12. Permit Documentation

May 8, 1995	Air Quality Construction Permit No. 9531-AA003 issued to North Pole Power Plant (NPPP)
August 9, 2002	Golden Valley Electric Assoc. (GVEA) submits Air Quality Construction Permit Application for NPPP Combined-Cycle Project
August 14, 2002	ADEC application incompleteness email to Kate Lamal, Vice President Power Systems, Golden Valley Electric Assoc., Inc., request for additional information.
August 27, 2002	EPA completes their review of the GVEA North Pole Power Plant Title V Operating Permit 110TVP01.
August 28, 2002	GVEA response to ADEC August 14, 2002 request for additional information from Kate Lamal, Vice President Power Systems, Golden Valley Electric Assoc., Inc.
November 29,2002	GVEA submits to ADEC the Certification of the additional information supplied by GVEA for the NPPP Combined Cycle Project.
December 24, 2002	The preliminary Construction Permit and the revised Operating Permit were issued for Public Comment.
January 7, 2003	A Public Hearing was held at the North Pole City Council Chambers.
January 28, 2003	Williams Alaska Petroleum, Inc. comments on GVEA's preliminary Air Quality Construction Permit No.110 CP 01 and Air Quality Operating Permit No. 110 CP 01 Revision1.
January 31, 2003	GVEA comments on preliminary Air Quality Construction Permit No.110 CP 01 and Air Quality Operating Permit No. 110 TVP 01 Revision: 1.
April 25, 2003	GVEA submitted to ADEC the request to revise the preliminary Air Quality Permit No. 110 CP 01 and Air Quality Operating Permit No. 110 TVP 01 Revision: 1.
May 10, 2005	Letter from Henrik Wessel (GVEA) to Bill Walker (ADEC) requesting revisions to Permit No. 110CP01. (Incomplete application)
November 14, 2005	May 10, 2005 Application Supplement.