Hilcorp
North Slope, LLC

May 26, 2022

Sent via Email and Postal Service

Alaska Department of Environmental Conservation Air Permits Program
Attn: Air Permit Application Intake Clerk
555 Cordova Street
Anchorage, AK 99501
dec.ag.airreports@alaska.gov

Subject: **Gathering Center #2 (Permit No. AQ0183MSS03 Revision 1)**
Revise/Rescind Title I Terms or Conditions Application

Dear Sir or Madam:

By this letter and attached application, Hilcorp North Slope, LLC (Hilcorp) seeks removal of the GTS Energy Bath Heater (tag # H-Z06111, EU ID 36) from certain conditions in Gathering Center #2 (GC-2) permit AQ0183MSS03 Revision 1 and removal of the SO_2 Best Available Control Technology (BACT) limit on EU ID 5. All the revisions are considered permit hygiene and do not change the source potential to emit (PTE). The application is submitted by email along with one original printed application.

This application is submitted under Alaska Department of Environmental Conservation (ADEC) Air Quality Control Regulations 18 AAC 50.508(6). Accordingly, this permit application contains the information required under 18 AAC 50.540(a), (b), and (k), which is presented as an attachment to this letter.

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.

If you have any questions or require additional information, please contact Natalia Lau at 907.777.8304 or Natalia.Lau@hilcorp.com.

Sincerely,

Jill Fisk

Jill Fisk
Sr. Asset Team Leader – Prudhoe Bay West
Hilcorp North Slope, LLC

cc: Greg Arthur (Hilcorp)
Sims Duggins (SLR International Corporation)

Enclosures:

Attachment A	Stationary Source Identification Form
Attachment B	Copy of Minor Permit AQ0183MSS03, Revision 1 and associated Technical Analysis Report

ATTACHMENT A

Stationary Source Identification Form

Alaska Department of Environmental Conservation
Air Quality Minor Permit Application

ATTACHMENT A
STATIONARY SOURCE IDENTIFICATION FORM

Section 1 Stationary Source Information

Name: Gathering Center 2 (GC-2)			SIC:1311
Project Name (if different): Z-Pad Related Revisions to AQ0183MSS03	Contact: Natalia Lau		
Physical Address: Section 16, Township 11N, Range 13E, Umiat Meridian	City: Prudhoe Bay Oil Field	State: AK	Zip:
	Telephone: (907) 777-8304		
	E-Mail Address: Natalia.Lau@hilcorp.com		
UTM Coordinates (m) or Latitude/Longitude:	Northing:	Easting:	Zone:
	Latitude: 70° 18’ 42” North	Longitude: 148° 51’ 35” West	

Section 2 Legal Owner

Name: SEE BOTTOM OF THIS PAGE		
Mailing Address:		
City:	State:	Zip:
Telephone #:		
E-Mail Address:		

Section 3 Operator *(if different from owner)*

Name: Hilcorp North Slope, LLC		
Mailing Address: 3800 Centerpoint Drive, Suite 1400		
City: Anchorage	State: AK	Zip: 99503
Telephone #: NA		
E-Mail Address: NA		

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

Name: CT Corporation Systems		
Mailing Address: 9360 Glacier Hwy, Suite 202		
City: Juneau	State: AK	Zip: 99801
Telephone #: (907) 586-3340		
E-Mail Address: NA		

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

Name: Accounts Payable		
Mailing Address: PO Box 61529		
City: Houston	State: TX	Zip: 77208
Telephone #: (713) 209-2400		
E-Mail Address: NA		

Section 6 Application Contact

Name: Natalia Lau			
Mailing Address: Same as Operator	City:	State:	Zip:
	Telephone: (907) 777-8304		
	E-Mail Address: Natalia.Lau@hilcorp.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)]

Legal Owners

Hilcorp North Slope, LLC
3800 Centerpoint Drive, Suite 1400
Anchorage, AK 99503

ConocoPhillips Alaska, Inc.
700 G Street (zip 99501)
P.O. Box 100360
Anchorage, AK 99510-0360

ExxonMobil Alaska Production, Inc.
3301 C Street, Suite 400 (zip 99503)
P.O. Box 196601
Anchorage, AK 99519-6601

Chevron USA, Inc.
P.O. Box 36366
Houston, TX 77236

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: AQ0183MSS03, Revision 1
Date: August 1, 2013

**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)*: AQ0183TVP01, Rev 6
AQ0183MSS03, Rev 1

☐ 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.

With this application, Hilcorp North Slope, LLC (Hilcorp) seeks removal of the GTS Energy Bath Heater (tag # H-Z06111, EU ID 36) from certain conditions in GC-2 permit AQ0183MSS03 Revision 1 and removal of the SO_2 Best Available Control Technology (BACT) limit on EU ID 5. All the revisions are considered permit hygiene and do not change the source potential to emit (PTE) since the changes are the result of the following prior permit actions.

- EU ID 36 is located on Z-Pad. Revisions related to this EU are requested because Z-Pad is no longer aggregated with GC-2 for air quality permitting, and Hilcorp recently applied for a source-specific permit for Z-Pad[1]. Z-Pad was disaggregated from the GC-2 stationary source effective January 1, 2019[2]. GC-2 permit AQ0183MSS03 Revision 1 was not revised at that time because it contained minimal pad-specific requirements, Z-Pad emissions were not large enough to require a source-specific permit, and the complexity associated with removing EU ID 36 from the SO_2 monitoring, recordkeeping, and reporting requirements found in conditions 10 through 12. This approach worked well in 2019 because Z-Pad did not have a source-specific permit. Having a source-specific permit for emissions units at Z Pad will thereby fully disaggregate the Z Pad emissions units from the GC-2 stationary source once the MR&R in Conditions 10 through 12 of the MSS03 permit sunset on March 1, 2023.

- The most recent GC-2 permitting action removed conditions associated with the Environmental Protection Agency (EPA) SO_2 BACT limit for EU ID 5, which was established in permit PSD-X81-13. This EPA SO_2 BACT limit has been superseded by a 200 parts per million by volume (ppmv) fuel gas hydrogen sulfide (H_2S) BACT limit set during a Prevention of Significant Deterioration (PSD) permitting action completed by ADEC as detailed in the Title V operating permit minor modification application submitted to the Department and EPA by BP Exploration (Alaska) Inc. on May 19, 2020.

The current GC-2 PTE incorporating these revisions is detailed in the May 19, 2020, application.

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[1] Z-Pad Power Expansion Project Air Quality Minor Permit Application, submitted to ADEC February 28, 2022

[2] As stated in the cover letter to the Title V Operating Permit (AQ0183TVP01) Minor Modification Application for Gathering Center #2, Well Pad Disaggregation, submitted to ADEC December 27, 2018, by BP Exploration (Alaska) Inc.

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 to this application

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 to this application

- The emission limitation representing that quantity of emission reduction.

Not applicable to this application

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 to this application

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 to this application

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 to this application

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 to this application

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)];

Cover Page: Remove the Z-Pad reference in the Physical Address. Z-Pad has been disaggregated from the GC-2 stationary source; therefore, this reference is no longer relevant.

Table 1: Remove the entire last row which lists well pads and footnote 2. These well pads have been disaggregated from the GC-2 stationary source; therefore, these references are no longer accurate.

Table 1: To clarify that Z-Pad has been disaggregated from the GC-2 stationary source, add a footnote to EU ID 36 that states, "*While Z-Pad has been disaggregated from the GC-2 stationary source, the GTS Energy Bath Heater located at Z-Pad (identified as EU 36) temporarily remains in this permit because it is part of the MR&R requirements in Conditions 10 through 12 which require the Permittee to demonstrate that the increase in SO_2 emissions resulting from the Hydrogen Sulfide Limit Increase Project does not reach 40 tpy. These requirements apply until March 1, 2023.*"

Condition 2.1: Revise the assessable potential to emit (PTE) to 2,828 tpy to make it consistent with the PTE documented in prior permit actions. Those actions resulted in removal of the PTE of the Z-Pad GTS Energy Bath Heater when Z-Pad was disaggregated from the GC-2 stationary source as of January 1, 2019, and the change in PTE that resulted from removing the EPA SO_2 BACT limit of 1.5 tpy applicable to EU ID 5 and replacing it with a fuel gas H_2S content limit of 200 ppmv based on the Title V operating permit minor modification application submitted to the Department and EPA on May 19, 2020.

Conditions 4, 5, and 6: Remove the references to EU ID 36. Compliance with State Emissions Standards by EU ID 36 will be a requirement of the Z-Pad minor stationary source permit (Z-Pad Power Expansion Project) to be issued.

Conditions 7.2b, 7.2c, and 7.2e(iii): Remove the references to EU ID 36. Limits and associated monitoring, recordkeeping, and reporting necessary to protect ambient air quality because of significant impacts from EU ID 36 will be established in the Z-Pad minor stationary source permit for the Z-Pad Power Expansion Project. This is not only because Z-Pad has been disaggregated from the GC-2 stationary source but also because a Z-Pad specific ambient air quality impact analysis demonstrating the limits necessary to protect air quality is included in the Z-Pad Power Expansion Project minor stationary source permit application.

Condition 9, Table 2: Remove the 1.5 tpy SO_2 emission BACT limit for EU ID 5. The EPA SO_2 BACT limit has been superseded by the fuel gas H_2S content limit of 200 ppmv based on the Title V operating permit minor modification application submitted to the Department and EPA on May 19, 2020. The suggested change is as follows:

Table 2: Turbine H_2S/SO_2 BACT Limits

Pollutant	EU	Make/Model	Equipment Tag Number	Emission Limit
~~SO_2~~	5	Sulzer 3	GTRB-02-7704B	~~1.5 tpy~~
H_2S				200 ppmv H_2S content in fuel gas (annual average)

Conditions 10 through 12: No change requested. Though these conditions include references to EU ID 36, which is no longer part of the GC-2 stationary source, they also expire March 1, 2023. Therefore, Hilcorp believes it is better to let the conditions expire rather than attempt to remove the references to EU ID 36 and copy the MR&R found in these conditions into the Z-Pad Power Expansion Project minor permit for EU ID 36, which could be confusing.

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

- Emissions;

The revisions requested result from prior permitting actions; therefore, the effect of the requested revisions have already been accounted for, and there is no change in GC-2 PTE.

- Other permit terms;

TAR: Please update text as necessary to reflect the change in ownership from BP Exploration (Alaska) Incorporated (BPXA) to Hilcorp North Slope, LLC (Hilcorp). Also, revise the TAR as necessary to document the revisions requested to the GC-2 minor stationary source permit as part of this application.

TAR Section 3.1, Table 2: PTE and Assessable Emissions should be revised as follows:

PTE and Assessable Emissions (tons per year (tpy))

Description	NO_X	CO	PM-10	SO_2	VOC	Total
Stationary source-wide PTE and Assessable Emissions	1,973	564	53	191	47	2,828

- The underlying ambient demonstration, if any;

None of the changes affect the underlying GC-2 ambient demonstration based on the following:

  - Regarding EU ID 36: Z-Pad is no longer part of the GC-2 stationary source and emissions units at Z-Pad are located too far from GC-2 to significantly contribute to GC-2 impacts. Therefore, removing EU ID 36 will not affect the GC-2 ambient demonstration. Furthermore, a Z-Pad specific ambient air quality impact analysis demonstrating the limits (as necessary) to protect air quality is included in the Z-Pad Power Expansion Project minor stationary source permit application submitted to ADEC February 28, 2022.
  - Regarding EU ID 5: As discussed on page 8 of the July 17, 2013, Modeling Review Report included as Appendix C of the TAR supporting Permit AQ0183MSS03 Revision 1, for both the short-term and annual SO_2 compliance demonstration, EU ID 5 was modeled with emissions based on a short-term gaseous fuel H_2S concentration limit of 200 ppmv (11.9 tpy). This is greater than the annual BACT limit of 1.5 tpy which is being removed. Therefore, removing the 1.5 tpy limit will not impact the underlying GC-2 ambient demonstration.

- Compliance monitoring; and

Not applicable to this application

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)]

Not applicable to this application

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 **Gathering Center 2** (Stationary Source Name) submitted to the Department on: 5/24/2022

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: Jill Fisk	Date: 5/26/22
Printed Name: Jill Fisk	Title: Sr. Asset Team Leader – Prudhoe Bay West

Section 15 Attachments

☒ Attachments Included. List attachments:

Attachment A – Stationary Source Identification Form (this form)

Attachment B - Copy of Minor Permit AQ0183MSS03, Revision 1 and associated Technical Analysis Report

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

ATTACHMENT B

A Copy of Minor Permit AQ0183MSS03, Revision 1 and Associated Technical Analysis Report

DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY CONTROL MINOR PERMIT

Minor Permit AQ0183MSS03 Revision 1 **Final – August 1 2013**

Rescinds Minor Permit AQ0183MSS03

The Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Minor Permit AQ0183MSS03 to the Permittee listed below.

Permittee:	BP Exploration (Alaska) Inc (BPXA) P.O. Box 196612 Anchorage, Alaska 99519
Owner(s):	See next page
Operator	Same as Permittee
Stationary Source:	**Gathering Center 2 (GC2)**
Location:	Latitude: 70° 18' 42" North; Longitude: 148° 51' 35" West
Physical Address:	Production Pad: Section 16, Township 11N, Range 13E, Umiat Meridian Z Pad: Section 19, Township 11N, Range 12E, Umiat Meridian
Project Name:	Hydrogen Sulfide Limit Increase Project
Permit Contact:	Alejandra Castano (907) 564-5338, Alejandra.Castano@bp.com

The permit is classified under 18 AAC 50.502(c)(3)(B)(ii) for a change in the method of operation of the stationary source that increases actual sulfur dioxide emissions by more than 10 tons per year and under 18 AAC 50.508(6) for revising the terms and conditions established in a Title I permit. This permit authorizes the Permittee to increase the fuel gas hydrogen sulfide limit and establishes other limits to protect ambient air quality. The permit satisfies the obligation of the Permittee to comply with the air quality regulations under 18 AAC 50. As required by AS 46.14.120(c) the Permittee shall comply with the terms and conditions of this permit.

John F. Kuterbach, Manager
Air Permits Program

Legal Owners Names and Addresses

BP Exploration (Alaska) Inc.
900 East Benson Blvd (zip 99508)
P.O. Box 196612
Anchorage AK, 99519-6612

ExxonMobil Alaska Production, Inc.
3301 C Street, Suite 400 (zip 99503)
P.O. Box 196601
Anchorage, AK 99519-6601

ConocoPhillips Alaska, Inc.
700 G Street (zip 99501)
P.O. Box 100360
Anchorage, AK 99510-0360

Chevron USA, Inc.
P. O. Box 36366
Houston, TX 77236

Abbreviations/Acronyms

AAC	Alaska Administrative Code
AS	Alaska Statute
ASTM	American Society of Testing and Materials
BACT	Best Available Control Technology
BPXA	BP Exploration (Alaska) Incorporated
Department	Alaska Department of Environmental Conservation
EPA	Environmental Protection Agency
EU	Emission Unit
GC2	Gathering Center 2
ISO	International Standards Organization
HHV	Higher Heating Value
ORL	Owner Requested Limits
PSD	Prevention of Significant Deterioration
wt%	percent by weight

Units and Measures

hp	horsepower
kW	kilowatts (electric)
lb	pounds
MMBtu/hr	million British thermal units per hour
MMscf	million standard cubic feet
MMscf/day	million standard cubic feet per day
ppmv	parts per million by volume
ppmw	parts per million by weight
scf	standard cubic feet
tpy	tons per year

Pollutants

CO	Carbon Monoxide
H_2S	Hydrogen Sulfide
NOx	Oxides of Nitrogen
O_2	Oxygen
PM	Particulate Matter
SO_2	Sulfur Dioxide

Table of Contents

Section 1. Emission Unit Inventory

1. **Emission Unit (EU) Description.** Except as noted elsewhere in this permit, the information in Table 1 is for identification purposes only. The specific EU descriptions do not restrict the Permittee from replacing an EU identified in Table 1. The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement EU, including any applicable minor or construction permit requirements.

Table 1 - EU Inventory at Gathering Center #2 (GC2)

EU ID	Tag Number	Emission Unit Description	Rating / Size	Commenced Construction Date
Group I: Gas-Fired Turbines at Production Pad				
1	GTRB-02-7000	GE MS5382C Compressor	38,000 hp ISO	Modified 1999
2	GTRB-02-7001	GE MS5382C Compressor	38,000 hp ISO	Modified 1999
4	GTRB-02-7704A	Sulzer S3 Pump	7,910 hp ISO	Prior to 8/82
5	GTRB-02-7704B	Sulzer S3 Pump	7,910 hp ISO	Prior to 03/83
6	GTRB-02-7529	Ruston TB 5000 Pump	4,900 hp ISO	Prior to 12/81
7	GTRB-02-7504A	Ruston TA 2500 Pump	2,500 hp ISO	Prior to 12/81
8	GTRB-02-7504B	Ruston TA 2500 Pump	2,500 hp ISO	Prior to 12/81
Group II: Gas-Fired Heaters and Reboilers at Production Pad				
9	B-02-7000	Cleaver Brooks 200800 EG Heater (Dual Fired)	33.5 MMBtu/hr each (Heat Input, LHV)	Prior to 12/81
10	B-02-7001			Prior to 12/81
11	B-02-7002			Prior to 12/81
12	B-02-0001	Cleaver Brooks 200500 EG Boiler (Dual Fired)	20.9 MMBtu/hr each (Heat Input, LHV)	Prior to 4/77
13	B-02-0002			Prior to 4/77
14	B-02-0003	Cleaver Brooks 200500 EG Heater (Dual Fired)		Prior to 4/77
15	B-02-0004			Prior to 4/77
16	B-02-0067	BS&B TEG Reboiler	7.73 MMBtu/hr each (Heat Input, LHV)	Constructed prior to 4/1977, Modified 8/2004
17	B-02-0068	BS&B TEG Reboiler		
Group III: Liquid Fuel-Fired Equipment at Production Pad				
18	GNED-02-0001	Detroit Diesel Emergency Generator	737.6 hp each (550 kW)	Approximately 1976/77
19	GNED-02-0002			
20	GNED-01-0011			
21	PED-02-0049	Detroit Diesel Emergency Firewater Pump	280 hp each	Approx 1976/77
22	PED-02-7004			Approx 1982/83
23	GNED-02-7500	Detroit Diesel Emergency Generator	3,600 hp (2,685 kW)	Approx 1981/82
24	GTRB-02-8001	Allison 501KB Emergency Turbine Generator	5,000 hp (3,730 kW)	Approx 1983/84
37	PED-02-8001	Detroit Diesel Black Start Engine for EU 24	160 hp	Approx 1983/84
Group IV – Flares at Production Pad				
27	FL-02-0003	KALDAIR LP/HP Vertical Emergency Flares	1.18 MMscf/day (Pilot & Purge)	Approximately 1977
28	FL-02-0004			
29	FL-02-0005	KALDAIR HP Vertical Emergency Flares		
30	FL-02-0006			
31	FL-02-0007			
32	FL-02-0008	National Horizontal Burn Pit Emergency Flare		Unknown
Group V – Fixed Roof Storage Tanks > 10,000 Gallon Capacity at Production Pad[1]				

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[1] The storage tanks do not have Title I requirements but are included for completeness and consistency with the EU inventory table in GC2's Title V permit

EU ID	Tag Number	Emission Unit Description	Rating / Size	Commenced Construction Date
33	T-02-7703	Oil Skim Storage Tank	493,500 gallons	1982
34	T-02-8511	Oil Skim Storage Tank	577,122 gallons	Installed 1991
35	T-02-8512	Oil Skim Storage Tank	577,122 gallons	Installed 1991
Other				
36	H-Z06111	GTS Energy Bath Heater (Fuel Gas)	37 MMBtu/hr (heat input); HHV	6/27/2006
Well Pads H, J, M, N, Q, R, S, U, W, and Z[2]				

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[2] There are no permanent emission units located at the well pads.

Section 2. Emission Fees

2. **Assessable Emissions.** 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 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 2,892 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 Air Permits Program, ATTN: Assessable Emissions Estimate, 410 Willoughby Ave., Suite 303, 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.

Section 3. State Emission Standards[3]

4. **Visible Emissions**: The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from EUs 1, 2, 4 through 24, 27 through 32, 36, and 37 listed in Table 1 to reduce visibility through the exhaust effluent by more than 20% averaged over any six consecutive minutes.

    4.1 Monitor, record, and report as described in the operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50.

5. **Particulate Matter**: The Permittee shall not cause or allow particulate matter emitted from EUs 1, 2, 4 through 24, 27 through 32, 36, and 37 listed in Table 1 to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.

    5.1 Monitor, record, and report as described in the operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50.

6. **Sulfur Compound Emissions**: The Permittee shall not cause or allow sulfur compound emissions, expressed as sulfur dioxide (SO_2), from EUs 1, 2, 4 through 24, 27 through 32, 36, and 37 listed in Table 1 to exceed 500 parts per million (ppm) averaged over three hours.

    6.1 Monitor, record, and report as described in the operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50.

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[3] Carried over from previous construction permit action (Operating / Construction Permit AQ0183TVP01) and updated to match current regulatory language.

Section 4. Ambient Air Quality Protection Requirements

7. The Permittee shall protect the 1-hour, 3-hour, 24-hour and annual average sulfur dioxide (SO_2) Alaska Ambient Air Quality Standards and the 3-hour, 24-hour and annual average SO_2 increments by complying with Conditions 7.1 and 7.2.

7.1 **Liquid Fuel Sulfur Content**: The sulfur content of liquid fuel burned in EUs 9 through 15 and EUs 18 through 24 listed in Table 1 shall not exceed 0.11 percent by weight (wt%) at any time.

a. Monitor and record the sulfur content of the liquid fuel delivered to the stationary source as described in the operating permit issued to the stationary source under AS 46.14.130(b) and 18 AAC 50.

b. Report in the operating report described in the operating permit issued to the stationary source under AS 46.14.130(b) and 18 AAC 50 the sulfur content of the liquid fuel recorded under Condition 7.1a.

c. Report as permit deviations as described in the operating permit issued to the stationary source under AS 46.14.130(b) and 18 AAC 50 if the sulfur content of the liquid fuel recorded under Condition 7.1a exceeds 0.11 wt% at any time.

7.2 **Hydrogen Sulfide (H_2S) Content of Fuel Gas**: Limit, monitor, record, and report the H_2S content of the fuel gas burned as follows:

a. The H_2S content of the fuel gas burned in EUs 1, 2, 4, 6 through 8, EUs 9 through 15, EUs 16 and 17, and flares EU 27 through 32 listed in Table 1, shall not exceed at any time:

(i) 125 parts per million by volume (ppmv) when the sulfur content of the liquid fuel burned by any of EUs 9 through 15 or 18 through 24 is greater than 15 parts per million by weight (ppmw); and

(ii) 185 ppmv when the sulfur content of the liquid fuel burned by all of EUs 9 through 15 and 18 through 24 is 15 ppmw or less.

b. The H_2S content of the fuel gas burned in EUs 5 and 36 listed in Table 1 shall not exceed 200 ppmv at any time.

c. Measure [4]monthly and record the H_2S content of the fuel gas burned in EUs 1, 2, 4 through 8, dual fuel EUs 9 through 15, EUs 16 and 17, and flares EU 27 through 32 and EU 36 listed in Table 1 as described in the operating permit issued to the stationary source under AS 46.14.130(b) and 18 AAC 50.

d. Report in the operating report described in the operating permit issued to the stationary source under AS 46.14.130(b) and 18 AAC 50 the H_2S content of the fuel gas recorded under Condition 7.2c.

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[4] The Permittee may use a single fuel gas H_2S measurement to satisfy the requirement in Condition 7.2c for several EUs if the fuel gas burned in the EUs is common to all of the applicable EUs.

e. Report as permit deviations as described in the operating permit issued to the stationary source under AS 46.14.130(b) and 18 AAC 50 if the H_2S content of the fuel gas measured under Condition 7.2c exceeds at any time:

(i) 125 ppmv when the sulfur content of the liquid fuel burned by any of EUs 9 through 15 and 18 through 24 listed in Table 1 is greater than 15 ppmw;

(ii) 185 ppmv when the sulfur content of the liquid fuel burned by all of EUs 9 through 15 and 18 through 24 listed in Table 1 is 15 ppmw or less; or

(iii) 200 ppmv for EUs 5 or 36.

8. The Permittee shall protect the 1-hour and annual average SO_2 Alaska Ambient Air Quality Standards and the annual average SO_2 increment by complying with Condition 8.1.

8.1 **Operating Hours of Emergency Equipment**[5]: The Permittee shall operate EUs 18 through 24 listed in Table 1 for no more than 200 hours each per consecutive 12-month period.

a. Monitor and record monthly the total hours each EU listed in Condition 8.1 operated during the month and during the preceding consecutive 11 months;

b. Report in the operating report described in the operating permit issued to the stationary source under AS 46.14.130(b) and 18 AAC 50 the operating hours recorded under Condition 8.1a.

c. Report as permit deviations as described in the operating permit issued to the stationary source under AS 46.14.130(b) and 18 AAC 50 if the operating hours recorded under Condition 8.1a for any EU listed in Condition 8.1 exceed the limit in Condition 8.1.

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[5] The 200 hr/yr operating hour limits originated in Permit-to-Operate 9473-AA033. The Department's modeling review determined that the operating time limits protect ambient air quality.

Section 5. Best Available Control Technology (BACT)

9. **Turbine H_2S/SO_2 BACT Emission Limits[6]:** The Permittee shall limit emissions from EU 5 as indicated in Table 2.

Table 2: Turbine H_2S/SO_2 BACT Limits

Pollutant	EU	Make / Model	Equipment Tag Number	Emission Limit
SO_2	5	Sulzer 3	GTRB-02-7704B	1.5 tpy
H_2S				200 ppmv H_2S content in fuel gas (annual average)

9.1 Monitor, record, and report as described in the operating permit issued to the stationary source under AS 46.14.130(b) and 18 AAC 50 to demonstrate compliance with the turbine BACT limits in Table 2.

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[6] The SO_2 limits are from federal PSD Permit no. PSD-X81-13.

Section 6. *MR&R for SO_2 Emissions from Fuel Gas Combustion*

10. **Monitoring**: Beginning in 2013 and ending in 2022, the Permittee shall monitor emissions from EUs 1, 2, 4 through 17, 27 through 32, and 36 listed in Table 1, and beginning in 2014 and ending in 2023, the Permittee shall calculate calendar year SO_2 emissions from the EUs as follows:

    10.1 Monitor and record the amount of fuel gas burned in million standard cubic feet (MMscf) during each calendar month of the calendar year using a fuel gas meter calibrated to manufacturer's specifications.

    10.2 Calculate the total SO_2 emissions for each calendar month of the calendar year using the amount of fuel gas recorded in Condition 10.1, H_2S content of the fuel gas measured in Condition 7.2c, and the equation given below:

$$tons\ SO_2 = [[(MMscf) \times (ppmv\ H_2S) \div (379.6\ scf\ per\ mole)] \times (64\ lb\ SO_2\ per\ mole\ H_2S)] \div 2000$$

    10.3 By February 15th of each calendar year, calculate the total SO_2 emissions for the preceding calendar year by summing the emissions calculated in Condition 10.2 for the 12 months in the preceding calendar year.

    10.4 By February 15th of each calendar year, determine the net change in SO_2 emissions in tpy for the preceding calendar year as follows:

    Net Change in Emissions = (Emissions calculated in Condition 10.3) – 14.0 tpy

11. **Recordkeeping**: The Permittee shall maintain the following records for EUs 1, 2, 4 through 17, 27 through 32, and 36 and make them available to Department personnel on request.

    11.1 The fuel gas consumed (in MMscf) for each calendar month of the calendar year;

    11.2 The average fuel gas H_2S concentration (in ppmv) data for each calendar month of the calendar year;

    11.3 The actual total SO_2 emissions for each calendar month of the year estimated under Condition 10.2 and supporting calculations used to obtain the emission estimates;

    11.4 The actual total SO_2 emissions for each calendar year estimated under Condition 10.3 and supporting calculations used to obtain the emission estimates; and

    11.5 The net change in SO_2 emissions for each calendar year determined under Condition 10.4.

12. **Reporting:** For EUs 1, 2, 4 through 17, 27 through 32, and 36 in Table 1, the Permittee shall report as follows:

    12.1 For calendar years 2013 through 2022, report in the operating report required in the operating permit issued for the stationary source under AS 46.14.130(b) and 18 AAC 50 the following information

a. SO_2 emissions for each calendar month of the year calculated in Condition 10.2; and

b. in the final operating report for the calendar year, report the net change in SO_2 emissions calculated in Condition 10.4 for the calendar year ending with the last month of the reporting period.

12.2 By March 1st of each calendar year in years 2014 through 2023, report the following information to the Department if the net change in SO_2 emissions calculated under Condition 10.4 for the preceding year reaches or exceeds 40 tpy:

a. The annual emissions calculated in Condition 10.3 and the net change in emissions calculated in Condition 10.4; and

b. Any other information that the Permittee wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection)[7]

12.3 Report as a permit deviation in the report required in the operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50 if monitoring, recordkeeping, or reporting under Conditions 10, 11 or 12 is not completed as required.

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[7] BPXA understands that they are required to submit a PSD permit application if the net change in emissions calculated under Condition 10.4 for the preceding year reaches or exceeds 40 tpy.

Section 7. Standard Permit Conditions

13. **Compliance Requirements**: Compliance with permit terms and conditions is considered to be in compliance with those requirements that are

    13.1 included and specifically identified in the permit; or

    13.2 determined in writing in the permit to be inapplicable.

14. **Grounds for Action**: 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 the Clean Air Act (except for those terms or conditions designated in the permit as not federally enforceable), and is grounds for

    14.1 an enforcement action;

    14.2 permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280; or

    14.3 denial of an operating permit application.

15. **Non-Defense for Enforcement Action:** 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.

16. **Access**: 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:

    16.1 enter upon the premises where a source subject to this permit is located or where records required by the permit are kept;

    16.2 have access to and copy any records required by this permit;

    16.3 inspect any stationary source, equipment, practices, or operations regulated by or referenced in the permit; and

    16.4 sample or monitor substances or parameters to assure compliance with the permit or other applicable requirements.

17. **Independence of Permit Terms**: 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. **Changes in Permit**: The permit may be modified, reopened, revoked and reissued, or terminated for cause. A request by the Permittee for modification, revocation and reissuance, or termination or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

19. **Property Rights**: The permit does not convey any property rights of any sort, nor any exclusive privilege.

20. **Information Requests**: The Permittee shall furnish to the Department, within a reasonable time, any information that 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.

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

22. **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: Compl**i**ance 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 21.

23. **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.

Section 8. Permit Documentation

December 7, 2011	E-mail from Rachel Buckbee (BPXA) to Pat Dunn and Zeena Siddeek (ADEC) describing proposed permit application approach.
February 14, 2012	The Department received hard copy of the minor permit application in the Juneau office.
February 21, 2012	The Department's Permit Application Intake Clerk received BPXA's minor permit application to revise H_2S content of fuel gas burned at GC2.
February 21, 2012	Department determines application to be complete
August 3, 2012	Department publishes preliminary permit
August 31, 2012	BPXA requests extension of comment period.
September 4, 2012	The Department extends the comment period to September 14, 2012
September 14, 2012	Department receives comments on preliminary permit from BPXA.
March 8, 2013	Based on follow-up discussions between BPXA and the Department concerning GC1, GC2, GC3, and FS2, the Department removed permit conditions carried forward from EPA PSD permits that are not related to increase in H_2S content of the fuel gas.
May 22, 2013	BPXA sent an email requesting the Department to revise the heading of Condition 9, re-format Table 2, correct a referencing error, and make changes to the technical analysis report associated with the permit.
July 17, 2013	BPXA sent an email to the Department requesting the correction of typographical errors in the draft permit and the draft Technical Analysis Report the Department sent to BPXA on July 15, 2013 for review.

Attachment 1 - ADEC Notification Form[8]

Excess Emissions and Permit Deviation Reporting
State of Alaska Department of Environmental Conservation
Division of Air Quality

Gathering Center 2 (GC2)	AQ0183MSS03
Stationary Source Name	**Air Quality Permit No.**
BP Exploration (Alaska) Inc.	
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.

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[8] Revised as of September 27, 2010

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

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

☐ Opacity _______ %
☐ Fugitive Emissions
☐ Marine Vessel Opacity
☐ Venting ________ gas/scf
☐ Emission Limit Exceeded
☐ Flaring
☐ Control Equipment Down
☐ Other ________________

(f) Unavoidable Emissions:

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

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

Certify Report (Go to end of form.)

Section 2. Permit Deviations

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

☐ Emission Unit-Specific
☐ Failure to Monitor/Report
☐ General Source Test/Monitoring Requirements
☐ Recordkeeping/Reporting/Compliance Certification
☐ Standard Conditions Not Included in the Permit
☐ Other Section: ________________________ (Title of section and section number of your permit).
☐ Generally Applicable Requirements
☐ Reporting/Monitoring for Diesel Engines
☐ Recordkeeping Failure
☐ Insignificant Emission Unit
☐ Stationary Source Wide

(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
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.

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR PERMITS PROGRAM

TECHNICAL ANALYSIS REPORT

Air Quality Control Minor Permit AQ0183MSS03 Revision 1
BP Exploration (Alaska) Incorporated
Gathering Center 2

HYDROGEN SULFIDE LIMIT INCREASE PROJECT

Prepared by Kwame Agyei
Supervisor: Zeena Siddeek
Final – August 1, 2013

TABLE OF CONTENTS

ABBREVIATIONS/ACRONYMS

Acronyms

AAC	Alaska Administrative Code
AS	Alaska Statute
BACT	Best Available Control Technology
BPXA	BP Exploration (Alaska) Incorporated
CFR	Code of Federal Regulations
Department	Alaska Department of Environmental Conservation
EPA	United States Environmental Protection Agency
EU	Emission Unit
FOR	Facility Operating Report
GC2	Gathering Center 2
HHV	Higher Heating Value
ISO	International Standards Organization
MR&R	Monitoring, Recordkeeping, and Reporting
ORL	Owner Requested Limits
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
TAR	Technical Analysis Report
ULSD	Ultra Low Sulfur Diesel

Units and Measures

hp	horsepower
kW	kilowatts
lb	pound or pounds
lb/ton	pounds per ton
MMBtu/hr	million British Thermal Units per hour
MMscf	million standard cubic feet
MMscf/day	million standard cubic feet per day
ppmv	parts per million by volume
ppmw	parts per million by weight
scf	standard cubic feet
tpy	tons per year
wt%	weight percent

Pollutants

CO	Carbon Monoxide
H_2S	Hydrogen Sulfide
HAP	Hazardous Air Pollutant
NOx	Oxides of Nitrogen
PM-10	Particulate Matter with an aerodynamic diameter ≤ 10 microns
SO_2	Sulfur Dioxide
VOC	Volatile Organic Compound

1.0 Introduction

This Technical Analysis Report (TAR) provides the Alaska Department of Environmental Conservation's (Department's) basis for issuing Air Quality Control Minor Permit AQ0183MSS03 Revision 1 to BP Exploration (Alaska) Incorporated (BPXA) for their Gathering Center 2 (GC2). The Department is issuing AQ0183MSS03 Revision 1 under 18 AAC 50.502(c)(3)(B)(ii) for a change in the method of operation of an existing stationary source that increases actual sulfur dioxide (SO_2) emissions by more than 10 tons per year (tpy) and under 18 AAC 50.508(6) to revise existing Title I conditions at an existing stationary source. The Department will incorporate AQ0183MSS03 into GC2's operating permit by administrative amendment.

1.1 Stationary Source Description

BPXA is the Permittee and operator of GC2, a crude petroleum and natural gas production facility. The Standard Industrial Classification for GC2 is 1311 and the North American Industrial Classification System code is 211111. GC2 processes crude oil fluids received from various locations on the North Slope, including Well Pads H, J, M, N, Q, R, S, U, W, and Z of the Western Operating Area. GC2 can process more than 300,000 barrels of crude oil and 1.1 billion standard cubic feet of gas per day.

GC2 processes the three-phase crude oil to remove gas and water to meet the specifications for delivery to the Trans Alaska Pipeline System, dehydrates and compresses the removed gas for re-injection into reservoirs or used as fuel at GC2. GC2 processes the water to remove entrained crude oil before injection into wells. Energy required to support operations comes primarily from combustion of fuel gas produced locally at GC2.

GC2 has been operational at its current location since 1977. GC2 is a Prevention of Significant Deterioration (PSD) major source for having the potential to emit more than 250 tons per year (tpy) of carbon monoxide (CO) and nitrogen oxides (NOx). GC2 is not a hazardous air pollutants (HAPs) major source because it emits less than 10 tpy of any HAP and 25 tpy of total HAPs. BPXA currently operates GC2 under an application shield. Table 1 of Minor Permit AQ0183MSS03 presents the equipment at GC2.

1.2 Brief History of Hydrogen Sulfide (H_2S) Limit

The Department issued the initial permit-to- operate in 1975 before the PSD program began. The Department amended the permit three times in the 1970s and three times in the 1980s. The permits-to-operate did not list specific H_2S content limits but specified that the Permittee should operate the EUs as described in the respective permit applications. The Department does not have a record of all the applications but has a record of an application submitted on March 20, 1980 that described the fuel as natural gas with sulfur content of 2,000 grains per dry standard cubic feet. Another application submitted on August 18, 1981 described the fuel as natural gas with an H_2S concentration of 20 ppmv. The Department first documented an explicit fuel gas 25 ppmv H_2S limit on November 30, 1994 in Permit-to-Operate 9473-AA008. The permit did not specify an averaging period with the limit but did impose monthly fuel gas H_2S testing. The permit required BPXA to report the resulting SO_2 emissions monthly. The Department issued Permit-to-Operate 9473-AA033 a month later on December 27, 1994. Permit-to-Operate 9473-AA033 and an amendment issued on April 5, 1995 maintained these requirements.

BPXA submitted an application for a construction/operating permit on November 25, 1997. In that application and in a previous correspondence dated January 16, 1997, BPXA asked the Department to remove the H_2S limit except for EUs 3 and 5 approved under a PSD permit issued by EPA. BPXA stated none of the H_2S enforceability triggers listed in Permit-to-Operate 9473-AA033 existed for GC2 except EUs 3 and 5, nor had BPXA been required to maintain such a limit to demonstrate compliance with the ambient air quality standards or increments. BPXA also stated that for these EUs, EPA determined Best Available Control Technology (BACT) to be 20 ppmv H_2S which the Department subsequently raised to 25 ppmv[1].

The Department obliged BPXA's request by not carrying forward the H_2S limit to the Operating Permit AQ0183TVP01 issued on October 20, 2003 and only limited SO_2 emissions by Alaska State Implementation Plan[2] provisions for SO_2 for all EUs except EUs 1, 2, 3, and 5. BPXA requested the Department to carry forward the limit for EU 3 (now removed) and EU 5, because these EUs were subject to the EPA BACT limit. For EUs 1 and 2, BPXA requested the limit in conjunction with the Frame 5B to Frame 5C turbine upgrades in 1998. The 25 ppmv limit in the Operating Permit AQ0183TVP01 for EUs 1, 2, and 5 is listed as an annual average with the option to increase to 75 ppmv after conducting a modeling analysis.

2.0 Application Description

The Department received BPXA's application in the Anchorage office on February 21, 2012 requesting an increase in the H_2S limit in the fuel gas burned by EUs 1, 2, and 5. Because the Prudhoe Bay gas reservoir has soured over time, the H_2S content of the fuel gas burned at GC2 has gradually increased to the point where BPXA claims it cannot maintain continuous compliance with the 25 ppmv annual average limit in Operating /Construction Permit AQ0183TVP01 Revision 1 without curtailing production. Condition 6 limits the H_2S content of fuel gas burned in EUs 1, 2, and 5 to 25 ppmv (annual average). Condition 11 limits the H_2S content of fuel gas burned in EUs 1, 2, and 5 to 25 ppmv (with an option to increase it to 75 ppmv after the Department approves a modeling analysis). BPXA submitted the application assuming Condition 6 of AQ0183TVP01 Revision 1 is a BACT limit and Condition 11 is an ambient air quality protection limit.

The application fulfills requirements under 18 AAC 50.508(6) to revise permit conditions of a Title I permit and 18 AAC 50.502(c)(3)(B)(ii) for an actual increase in SO_2 emissions that triggers minor permit requirements.

In their comments on the preliminary permit, BPXA reiterated the Department should delete turbine EU 3 (Solar Mars turbine at W Pad), delete flares EUs 25 and 26, and correct the ratings of EUs 16 and 17 that resulted from an August 2004 upgrade.

BPXA's specific requests are:

- Delete EU 3 from the EU inventory and rescind all references to it because BPXA has permanently removed EU 3 from service;

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[1] In correspondence dated January 7, 2010, *(A Historical Perspective and Proposed Path Forward for the BPXA CPS, FS-2, GC-1, GC-2, and GC-3 Stationary Source Title V Permit Fuel Gas H_2S Limits*, Exhibit D, Page 1*)*, BPXA now asserts that EPA did not establish a fuel gas H_2S BACT limit in the PSD-X81-13 permit.

[2] The State Implementation Plan limit under 18 AAC 50.055(c) is equivalent to 4,000 ppmv H_2S.

- Revise the 25 ppmv annual average fuel gas H_2S BACT limit in Condition 6/Table 2 of AQ0183TVP01 for EU 5 to 200 ppmv (annual average);
- Revise the 25 ppmv annual average fuel gas H_2S air quality protection limit in Condition 11 of AQ0183TVP01 for EU 5 to a not-to-exceed 200 ppmv fuel gas H_2S air quality protection limit that applies at all times;
- For EUs 1 and 2, revise the annual average fuel gas H_2S owner requested limit in Condition 6 / Table 2 and the annual average fuel gas H_2S air quality protection limit in Condition 11 of AQ0183TVP01 as follows. For all other fuel gas-fired EUs (including all dual-fired units while burning gas), except EUs 5 and 36, establish new ambient air quality protection limits as follows:
    - A not-to-exceed 125 ppmv limit when the sulfur content of the liquid fuel burned by any EU at GC2 is greater than 15 parts per million by weight (ppmw); and
    - A not-to-exceed 185 ppmv limit when the sulfur content of the liquid fuel fired by all EUs at GC2 is 15 ppmw or less;
- Establish a limit for the H_2S content of the fuel gas burned in EU 36 of 200 ppmv (not to be exceeded) to protect ambient air quality[3];
- Establish a new liquid fuel sulfur content limit of 0.11 weight percent (wt%) for EUs 9 through 15 and 18 through 24 to protect the 24-hour SO_2 increment;
- Require monthly analysis to monitor the H_2S content of the fuel gas and sulfur content of the liquid fuel to show compliance with the 24-hour air quality increment standard;
- Require monitoring, recording, and reporting (MR&Rs) for SO_2 emissions from EUs 1, 2, 4 through 17, 27 through 32, and 36 as required by 40 CFR 52.21(r)(6) to demonstrate that the increase in SO_2 emissions resulting from the revisions does not reach 40 tpy; and
- Amend AQ0183TVP01 Revision 1 using the procedure specified at 18 AAC 50.542(e).

3.0 Emissions Calculations and Permit Applicability

The project does not increase emissions of any pollutant except SO_2. Appendix A presents actual SO_2 emissions. The PSD analysis did not include emissions from liquid-fired EUs because fuel gas souring has no effect upon their emissions.

Table A-1 of Appendix A presents the actual measured fuel gas H_2S concentrations for the period between 2000 through 2010. BPXA estimated the future actual H_2S content of the fuel gas as 60 ppmv. BPXA based the estimate on a statistical analysis of the fuel gas H_2S content measured from calendar year 2000 through 2010 and a 97.5 percent confidence level curve derived from the measured concentrations. The Department agrees with BPXA analysis that the future H_2S content will not exceed 60 ppmv in the next 10 years.

As allowed by the 40 CFR 52.21(b)(48)(ii), an applicant can choose any consecutive 24-month period within the 10-year period immediately preceding the project to estimate baseline actual

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[3] EU 36 is a bath heater at Z-Pad previously authorized under AQ0183MSS01. Section 2.3 of the TAR for AQ0183MSS01 says ‘BPXA conservatively assumed EU 36 will burn gas containing up to 200 ppmv H_2S. The Department believes the assumption of 200 ppmv is acceptable based on available data at GC2’. However, AQ0183MSS01 does not limit H_2S content of the fuel gas burned in EU 36.

emission (tpy). BPXA picked calendar years 2008 and 2009. BPXA calculated the baseline actual emissions (2008-2009) as 14.0 tpy and future actual emissions as 37.8 tpy. BPXA used fuel gas consumption and ppmv H_2S in Table A-3 to obtain the baseline actual and future actual emissions from mass balance.

The projected actual emissions increase estimated was 23.8 tons. Since the increase is greater than 50 percent of a significant emissions increase, BPXA must monitor for a period of 10 years and maintain a record of annual emissions for a period of 10 years as described in 40 CFR 52.21(r)(6) and 7.

3.1 Project SO_2 Emissions, Permit Applicability, and Assessable Emissions

Table 1 presents the permit applicability analysis for the project.

Table 1 –Permit Applicability

Description of SO_2 Emissions	Tons SO_2	Source or Reference
Baseline actual emissions from fuel gas combustion	14.0	Table A-3 of this TAR
Future actual emissions from fuel gas combustion	37.8	Table A-3 of this TAR
Emissions increase due to project	23.8	(Future-Baseline) Actual
Emission increase that requires PSD review	≥ 40	40 CFR 52.21(b)(23)(i)
Increase that requires modeling analysis	≥ 10	18 AAC 50.502(c)(B)(ii)
Is PSD review under 40 CFR 52.21 required?	No	
Is review under 18 AAC 50.502(c)(B)(ii) required?	Yes	

Table 2 presents potential-to-emit (PTE) and assessable emissions before and after the project. The Department based permit applicability in Table 1 on baseline actual to projected actual emissions and based assessable emissions in Table 2 on PTE. Therefore, assessable emissions are not related to the permit applicability.

Table 2: PTE and Assessable Emissions

Description	NO_x	CO	PM-10	SO_2	VOC	Total
Stationary source-wide PTE before project	2,001	607	55	38	38	2,739
Stationary source-wide PTE after project	2,001	607	55	191	38	2,892
Assessable Emissions	2,001	607	55	191	38	2,892

Table Notes
PTE after change obtained from Table G of Permit AQ0183TVP02 Statement of Basis.
SO_2 PTE before change obtained from Table A of AQ0183TVP01 Statement of Basis.
PTE excludes emissions from Nonroad Equipment.

3.2 Department Findings

The Department finds that:

1. GC2 is classified as a PSD major stationary source under 40 CFR 52.21(b)(1)(i) because it has the potential to emit more than 250 tpy of one or more pollutants. GC2 has the potential to emit more than 250 tpy of NOx and CO.
2. BPXA's application is classified under 18 AAC 50.508(6) because BPXA is requesting to revise existing Title I permit conditions.

3. BPXA’s application is classified under 18 AAC 50.502(c)(3)(B)(ii) because the actual projected SO_2 emissions increase at an existing stationary source exceeds 10 tpy.
4. Condition 6/Table 2 of AQ0183TVP01 Revision 1 describes the current 25 ppmv annual average H_2S limit for gas burned in EU 5 as BACT. Therefore, BPXA must submit a BACT analysis to revise the H_2S BACT limit for EU 5 from 25 ppmv (annual average) to 200 ppmv (annual average).
5. Condition 11 of AQ0183TVP01 Revision 1 describes the 25 ppmv annual average H_2S limit for fuel gas burned in EUs 1, 2, and 5 as an ambient air quality protection limit. Therefore, BPXA must submit a modeling analysis to support the request to increase the H_2S limit for fuel gas burned in EUs 1, 2, and 5 from 25 ppmv annual average to a not-to-exceed 125/185 ppmv depending on the sulfur content of the liquid fuel burned by liquid fuel-fired EUs.
6. Since the actual baseline SO_2 emissions for GC2 are 14 tpy from all fuel gas-burning EUs at GC2, future actual emissions from all fuel gas-burning EUs must be less than 54 tons per calendar year to not trigger PSD permit requirements.
7. Well Pads H, J, M, N, Q, R, S, U, W, and Z are part of GC2.

4.0 Permit Conditions

4.1 Minor Permit Content Under 18 AAC 50.544(a)

As described in 18 AAC 50.544(a)(1), each minor permit issued under 18 AAC 50.542 must identify the stationary source, the project, the Permittee, and contact information. The permit cover page identifies the stationary source, the project, Permittee and contact information.

As required under 18 AAC 50.544(a)(2), Section 2 of the minor permit contains fee requirements of 18 AAC 50.400 – 18 AAC 50.499. AQ0183MSS03 includes assessable emission fees.

As required under 18 AAC 50.544(a)(5), the minor permit contains standard permit conditions listed under 18 AAC 50.345(c) through (o) as applicable. These requirements are in Section 7 of the permit.

As required under 18 AAC 50.544(a)(6), Section 4 of AQ0183MSS03 contains conditions to protect ambient air quality. The Modeling Report in Appendix D details the Department’s review of BPXA’s modeling analysis and the permit conditions needed to protect the SO_2 ambient air quality standards and maximum allowable increases (increments).

As required under 18 AAC 50.544(a)(7) the permit contains the requirements under 40 CFR Part 71 as adopted by reference in 18 AAC 50.040(j) and 18 AAC 50.326 to accommodate an owner request to add the conditions of a minor permit to a Title V permit by administrative amendment. The revision to the H_2S limit in Condition 11 and Condition 6/Table 2 of Operating/Construction Permit AQ0183TVP01 does not revise the monthly monitoring requirements related to the fuel gas H_2S limits. However, there is additional monitoring for compliance with the liquid fuel sulfur content limit established in this permit action.

4.2 Permit Requirements for a Permit Under 18 AAC 50.508(6)

AQ0183MSS03 revises the existing fuel gas H_2S BACT limit from 25 ppmv annual average to 200 ppmv annual average.

In assessing the BACT revision request, the Department followed U.S. EPA guidance memo dated November 19, 1987[4] for revising the BACT limits. Specifically the memo states that prior to any revision to an existing BACT limit:

a. Source should investigate and report all available options to reduce emissions to a lower if not permitted level. BPXA has done all they can to reduce emissions to comply with the limits in the permit including curtailing production; and

b. If sufficient emission reduction down to the permitted level cannot be reasonably achieved, revising the limit may be warranted. BPXA has curtailed production to comply with their permit limits. The Department agrees that curtailing production is not a reasonable means to meet the limits.

c. The EPA guidance memo requires that the revision must also address all other PSD requirements including a new BACT analysis.

4.2.1 MR&R Requirements for SO_2 Emissions from Fuel Gas Combustion

BPXA projected the H_2S content of the fuel gas burned at GC2 will not exceed 60 ppmv within the next 10 years based on the past 10 years of recordkeeping. Using this 60 ppmv upper estimate and the quantity of fuel gas burned at GC2, BPXA projects the increase in SO_2 emissions at GC2 within the next 10 years will be less than the significant emissions increase of 40 tpy SO_2 under 40 CFR 52.21(b)(23)(i). Therefore, BPXA has demonstrated that the contemporaneous emissions increase resulting from fuel gas souring at GC2 does not trigger PSD review. This “baseline actual to projected actual applicability test” is allowed under the PSD rules as stated in 40 CFR 52.21(a)(2)(iv)(c) for projects that only involve existing emission units.

Since the projected 24 tpy SO_2 emissions increase is greater than 50 percent of the significant emission rate threshold of 40 tpy in 40 CFR 52.21(b)(23)(i), 40 CFR 52.21(r)(6) requires the Permittee to monitor, record, and report SO_2 emissions from the project to demonstrate that the actual emission increases will be less than 40 tpy. The Department has included monitoring, recordkeeping, and reporting (MR&R) requirements for tracking SO_2 emissions during the 10-year contemporaneous period to confirm that the actual increase in SO_2 emissions at FS2 will be less than 40 tpy during the 10-year contemporaneous period after the permit application was submitted (i.e., the project baseline).

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[4] November 19, 1987 Request for Determination on Best Available Control Technology (BACT) by Gary McCutchen and Micheal Trutna.

The Department is requiring BPXA to calculate the SO_2 emissions using the following equation:

$$E = [[(MMscf) \times (ppmv\ H_2S) \div (379.6\ scf\ per\ mole)] \times (64\ lb\ SO_2\ per\ mole\ H_2S)] \div 2{,}000$$

Where:

E = tons SO_2 emitted per year;
MMscf = million standard cubic feet (scf) of fuel gas burned during the year;
ppmv H_2S = H_2S content of the fuel (in parts per million by volume);
64 lb SO_2 per mole H_2S = molecular weight of SO_2
379.6 scf per mole = volume of one mole of an ideal gas at 60°F and 1 atmosphere.
2000 lb = 1 ton

4.2.2 SO_2 BACT Analysis

BPXA submitted a SO_2 BACT analysis for the H_2S content of the fuel gas burned in EU 5 because they are requesting to revise an existing BACT limit. The Department reviewed BPXA's SO_2 BACT analysis for EU 5. The Department agreed with BPXA's conclusion that BACT for EU 5 is 200 ppmv annual average H_2S content of the fuel gas based on the available fuel gas quality.

The lowest cost per ton for controlling SO_2 emissions from EU 5 exceeds $45,000. The Department agrees with BPXA that the control technologies are not cost effective for GC2. Table 3 presents the calculation of cost effectiveness for controlling SO_2 emissions for the control technologies identified. Appendix B presents the Department's review of the SO_2 BACT analysis for EU 5.

Table 3: Technically Feasible Control Technology Summary

Control Technology	Annualized Cost		Control Efficiency	Tons Removed	Removal Cost ($/ton	
	BPXA	Department			BPXA	Department
Liquid Redox (LO-CAT)	766,198	599,744	99	13.2	58,045	45,435
H_2S Solid Scavenger	864,103	812,258	95	12.6	68,580	64,465
H_2S Liquid Scavenger	639,850	625,136	95	12.6	50,782	49,614

Table Notes:

1. Tons removed is based on the projected uncontrolled emission rate of 13.3 tpy for EU 5 (at 200 ppmv fuel gas H_2S content) given in Table 2-1 of Attachment III of application and the control efficiency of the technology.
2. Annualized costs of the Department taken from Table B-3 through Table B-5 of the BACT analysis, Appendix B.

5.0 Permit Administration

BPXA is currently operating GC2 under expired Construction/Operating Permit AQ0183TVP01 and a permit application shield after applying for operating permit renewal. GC2 does not have any other active Title I permits issued by the Department. Construction/ Operating Permit AQ0183TVP01 incorporated all of the Title I conditions.

Minor Permit AQ0183MSS03 establishes additional monitoring requirements for liquid fuel sulfur. BPXA requested administrative revision of Title V Permit AQ0183TVP01 to incorporate Minor Permit AQ0183MSS03.

Appendix A: Gas Consumption, H_2S Content, and SO_2 Emissions

Table A-1: H_2S Content of Fuel Gas at GC2 (ppmv)

Year	Maximum Average Concentration				
	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual Average
2000					18.5
2001					22.0
2002					20.8
2003			20	15	15.0
2004	25				20.0
2005					21.7
2006					20.6
2007					25.4
2008	20.0	20.0	17.3	26.0	20.7
2009	33.3	26.3	21.3	27.7	26.6
2010	25.4	24.6	24.0	24.0	26.5
Future					60

Table: Notes:
Annual Average Concentration from 2000 through 2010 obtained from Table I-c-4 of GC2 application
Future Annual Average Concentration (60 ppmv) obtained from Figure I-c-1 of GC2 application
Quarterly ppmv obtained from available Facility Operating Reports BPXA submitted to Department.

Table A-2: Fuel Gas Consumption at GC2 (Million Standard Cubic Feet)

Equipment	2004	2005	2006	2007	2008	2009	2010
Turbines	6,373	6,404	6,093	5,842	6,495	6,017	6,240
Heaters	637	615	680	610	662	803	888
Flares	411	425	301	291	311	299	299
Total	7,421	7,445	7,074	6,743	7,468	7,118	7,427

Table Notes: The Department obtained fuel gas consumption from Table 1-c-5 of Attachment I of application.

Table A-3: Actual Fuel Gas Consumption and SO_2 Emissions at GC2

Year or Period	MMscf of Fuel Gas	ppmv H_2S in Fuel Gas	tpy SO_2 Emitted	tpy SO_2 Increase
2008	7,468	20.7	13.0	
2009	7,118	25.0 (permit limit)	15.0	
Baseline Actual			14.0	
Future Actual	7,468	60.0	37.8	23.8

Table Notes:
BPXA assumed future actual MMscf assumed as the 2008 (highest) consumption during the previous seven years
25 ppmv H_2S content for 2009 is the limit allowed by existing permit.
BPXA assumed a future actual H_2S content of 60 ppmv.
Increase in SO_2 emissions is 23.8 tpy and therefore project does not require PSD review.
tpy SO_2 = {[(MMscf) × (ppmv) ÷ (379.6 scf per mole)] × (64 lb SO_2 per mole H_2S) } ÷ (2,000 lb per ton)

Appendix B: SO_2 BACT Analysis for Emission Unit 5 at GC2

Section 1: Background

Fuel gas souring is occurring across the North Slope because of waterflood operations used in enhanced oil recovery. Souring results from bacteria which reduce the sulfate in the injected water into H_2S. As the water cuts in, the fluids produced from the wells increases, and more H_2S flashes off into the gas phase. The higher H_2S concentrations in the fuel gas result in higher SO_2 emissions from the combustion of the fuel gas. The Department estimates that SO_2 emissions from the combustion of the fuel gas at GC2 will increase from 14 tons per year (tpy) to about 38 tpy over the next 10 years (between 2012 and 2022). The Department considers the existing fuel gas H_2S limit in Condition 6/Table 2 of Title V Permit AQ0183TVP01 that applies to EU 5 as a Best Available Control Technology (BACT) limit. Therefore, BP Exploration Alaska (BPXA) submitted a BACT analysis to support their request to increase the H_2S content of the fuel gas burned in EU 5 from 25 ppmv annual average to 200 ppmv annual average.

Section 2: Standards and Steps for Making BACT Determinations

40 CFR 52.21(b)(12) and 40 CFR 51.166(b)(12) define BACT. The Department requires a BACT analysis to revise an existing BACT for any pollutant or for an emissions increase associated with a modification or change in the method of operation as defined in 40 CFR 52.21 and 40 CFR 51.166 that exceeds the PSD threshold. The goal is to identify BACT for SO_2 emissions, establish limits that represent BACT, and assess the level of monitoring, recordkeeping, and reporting necessary to ensure BPXA applies BACT at GC2 for the combustion of fuel gas in EU 5. The Department reviewed BPXA's BACT analysis for GC2's EU 5 in accordance with the top-down approach, as explained in detail below:

Step 1: Identify All Potentially Available Control Options

The Department identifies available control options for the emission unit and the pollutant under consideration. This includes technologies used throughout the world or emission reductions through the application of available control techniques, changes in process design, and operational limitations. To assist in identifying available controls, the Department reviewed available controls listed on the Reasonably Available Control Technology, BACT, and Lowest Achievable Emission Rate Clearinghouse (RBLC). The RBLC is a United States Environmental Protection Agency database where permitting agencies nationwide post imposed BACT for PSD sources. It is usually the first stop for BACT research.

Step 2 Eliminate Technically Infeasible Control Options

The Department evaluates the technical feasibility of each control option in relation to each emission unit subject to BACT. Based on sound documentation and demonstration, the Department then eliminates control options deemed technically infeasible due to physical, chemical, and engineering difficulties.

Step 3 Rank Remaining Control Technologies by Control Effectiveness

The Department ranks the remaining control options in order of control effectiveness with the most effective at the top. The applicant also presents detailed information about the control efficiency, emission rate, emission reduction, cost, environmental, and energy impacts for each option. An applicant that selects the most effective option does not need to provide detailed information for less effective options. If cost is not an issue, a cost analysis is not required.

Step 4 Evaluate the Most Effective Controls and Document the Results

The Department considers energy, environmental, and economic impacts to decide the final level of control. The applicant must present an objective evaluation of both the beneficial and adverse energy, environmental, and economic impacts. An applicant proposing to use the most effective option is not required to provide the detailed information for the less effective options.

Step 5 Select BACT

The Department selects the most effective control option not eliminated in Step 4 as BACT for the pollutant and emission unit under review and lists the final BACT requirements determined for each emission unit in this step. A BACT analysis is source-specific and should take into account energy, environmental, and economic impacts. Available control technologies may achieve emission reductions through the application of available technologies, changes in process design, and operational limitations.

The Department reviewed BPXA's BACT analysis and made a determination based on the:
(a) BACT analysis information submitted by BPXA in their application;
(b) Information from vendors, suppliers, and sub-contractors; and
(c) RBLC

The SO_2 BACT determination for combustion of fuel gas in EU 5 follows in Section 3.

Section 3: BACT Determination for SO_2 for Fuel Gas Combustion in EU 5

BPXA is requesting a BACT limit of 200 ppmv H_2S content for the fuel gas burned in EU 5. BPXA estimated the uncontrolled SO_2 emissions for the combustion of fuel gas containing 200 ppmv H_2S in EU 5 as 13.3 tpy.

BPXA provided examples of fuel gas burning equipment that are similar to EU 5 in Appendix B of BPXA's BACT analysis. Controls identified in the RBLC are the use of low sulfur fuel, pipeline quality natural gas, or good combustion practices. The RBLC did not specify add on controls as BACT for projects and permits listed. BPXA analyzed control options used to remove H_2S from the fuel gas before combustion and add-on controls used to remove SO_2 from the exhaust.

The following presents Department's review of BPXA's BACT analysis for the available SO_2 control options using the systematic top-down approach described previously. The steps discuss available control technologies the Department identified as of April 5, 2012.

3.1: Step 1: Identify All Control Technologies

BPXA identified seven technologies for removing H_2S from the fuel gas or removing SO_2 from the exhaust gases. The Department identified *Biocide Injection* and *Oxidation Process (Xergy Advanced Catalytic Technology*) in addition to those BPXA identified.

3.1.1: Add-on Flue Gas Desulfurization (FGD)

FGD is used for removing SO_2 from the exhaust. There are two types of FGD – wet and dry. In wet FGD, the flue gas is passed through packed towers, scrubbers, or spray chambers, which contain an alkaline slurry of water and lime, limestone, or some other alkaline sorbent. The scrubbing liquid is usually sodium hydroxide. The SO_2 in the flue gas reacts with the alkaline compounds to form sulfate particulates. Upon evaporation of the water, the particulates are collected in particulate control devices such as baghouses and electrostatic precipitators. In dry FGD systems, the flue gas reacts directly with lime to form solid calcium sulfate. The solid sulfates are collected in baghouses or electric precipitators.

FGD is typically used for high sulfur fuels such as coal or fuel oil. The SO_2 concentrations in the flue gas after combusting such fuels range from 250 to 10,000 ppmv. SO_2 removal efficiencies for typical wet FGDs exceed 90 percent.

The RBLC database does not contain applications of FGD systems as BACT for fuel gas-fired equipment. Add-on FGD systems are not technically feasible for controlling SO_2 emissions from EU 5 due to the relatively low concentration of SO_2 in the exhaust when burning fuel gas that contains no more than 200 ppmv H_2S.

3.1.2: Oil Reservoir Treatment Controls (Biocide Injection)

Application of biocides into an oil field can reduce the activity of the sulfate reducing bacteria and lower the H_2S content of the fuel gas. To be effective, biocides are introduced as high dose slugs over an extended interval of time. The ultimate effectiveness of biocide injection on H_2S content in fuel gas from the North Slope is unknown. Therefore, biocide injection is not technically feasible for controlling H_2S content of the fuel gas burned.

3.1.3: Liquid Redox (LO-CAT)

The liquid-redox process employs an aqueous based solution typically containing metal ions capable of transferring electrons in redox reactions. Gas Technology Products offers a commercial application called LO-CAT process. LO-CAT uses an environmentally safe dual-chelated iron catalyst to convert H_2S in the fuel gas to elemental sulfur.

The technology uses a countercurrent liquid-gas absorption tower. The fuel gas travels up the absorption tower and encounters the LO-CAT liquid solution flowing downward. Saturated sweet gas exits the top of the tower. The liquid solution then travels to a reaction vessel in which air is bubbled through the liquid and the H_2S is converted into water and solid sulfur. This suspension is filtered to remove the solid sulfur and returned to service in the countercurrent liquid-gas absorption tower. The sulfur is sent to a landfill for disposal.

To maintain the activity of the liquid catalyst solution, the LO-CAT system requires high purity water to replenish the patented LO-CAT liquid. GC2 would require a reverse osmosis unit to convert seawater to high purity water. Furthermore, the clean gas from the LO-CAT process requires drying before combustion in the equipment to prevent condensation of liquids in valves.

The LO-CAT process can achieve 99 percent or greater H_2S removal efficiencies in many different applications and industries. These applications range from a few standard cubic feet per minute to several million standard cubic feet per day. The sour gas entering the LO-CAT system may contain anywhere from 100 ppmv to 100 percent H_2S. The LO-CAT system is technically feasible for controlling SO_2 emissions at GC2.

3.1.4: H_2S Scavenging (SulfaTreat and Sulfa-Rite)

The process uses either solid or liquid scavengers with non-regenerable reaction systems. The most common systems are SulfaTreat and Sulfa-Rite. They both use an iron oxide scavenger. The fuel gas goes through a vessel containing the solid scavenger. The scavenger selectively captures the H_2S and chemically changes it to iron pyrite, a safe and stable compound. Optimum performance requires the fuel gas to be 60-80 percent saturated before entering the vessel.

The most common liquid scavenger is amine-aldehyde condensate offered as a water-based solution. The optimum liquid scavenger is methyl-triazine. A static mixer or a long pipe injects scavenger liquid directly into the gas stream. The efficiency of the system depends on the degree of mixing and is therefore sensitive to flow fluctuations.

After the catalyst converts the H_2S to iron pyrite, the clean gas requires cooling and drying. The clean gas contains water, carbon dioxide (CO_2), and low levels of H_2S, which requires stainless steel for corrosion protection. Once full of iron pyrite, the absorption system is removed from the catalyst bed as a spent wet material, dried and hauled off for waste disposal. The remaining water in the clean gas must be removed using a continuous re-generable desiccant system.

Generally, a H_2S scavenging system use a two bed re-generable desiccant system with one bed in the fuel gas drying stage and the other bed in the re-generation stage. The desiccant absorbs water from the fuel gas in the drying stage. The dry fuel gas is routed to the equipment. In the re-generation stage, an electric heater heats the clean dry fuel gas. The clean gas then passes over the desiccant bed containing the absorbed water molecules.

H_2S scavenging process is technically feasible for controlling SO_2 emissions at GC2.

3.1.5: Thiopaq / Shell-Paques Technologies

These are biotechnological processes for removing H_2S from gaseous streams by absorption into a mild alkaline solution followed by the oxidation of the absorbed sulfide to elemental sulfur by naturally occurring microorganisms. Thiopaq is specifically designed for low pressure (near atmospheric) biogas streams. It is a bio-catalyzed caustic scrubber process and operates at ambient temperatures and pressures. It does not require expensive catalysts and chemicals. The spent caustic solution is re-generated in the bioreactor. The H_2S removal can be as high as 99 percent.

The amount of water in the fuel gas or the dew point is a very critical for the process and safety. In an arctic environment, lines can freeze, causing safety hazards and production downtime. Thiopaq uses water in the treatment system, so in addition to producing water for the Thiopaq technology, the fuel gas stream requires re-conditioning to meet the arctic -50°F dew point requirement. The Thiopaq process is not suitable for arctic environments and for high-pressure fuel gas. Therefore, Thiopaq is not technically feasible for use at GC2.

The Shell-Paques process is very similar to the Thiopaq process except that it can accommodate low-high pressure fuel inlet gas streams (2 to 1,300 pounds per square inch gauge). A major difference is that the Shell-Paques process uses a flash vessel. In this process, a gas stream containing H_2S contacts an aqueous soda solution containing thiobacillus bacteria in an absorber. The soda absorbs the H_2S and goes through a flash vessel to remove dissolved hydrocarbon gases entrained in the spent scrubber solution. From the flash vessel, the solution is routed to an aerated atmospheric tank where the bacteria biologically convert the H_2S to elemental sulfur. The sulfur slurry may be disposed of or processed into sulfur cakes. Regenerated solvent from the bioreactor is pumped back to the scrubber for reuse.

In a previous BACT analysis, BPXA contacted NATCO, the licensed vendor for Shell-Paques as part of the BACT analysis associated with increasing the H_2S levels for BPXA's Central Gas Facility. NATCO said the technology was not suitable for Central Gas Facility since the ratio of CO_2 to H_2S and CO_2 partial pressure was too high. BPXA does not expect the concentration of H_2S in the fuel gas at GC2 to exceed 200 ppmv. The 300 ppmv H_2S content of the fuel gas at Central Gas Facility is higher than the expected 200 ppmv H_2S content of the fuel gas at GC2. Therefore, the ratio of CO_2 to H_2S and CO_2 partial pressure will even be higher at GC2.

BPXA determined Shell-Pacques is not feasible based on previous BPXA BACT determinations for similar plants and re-affirmed that Shell-Pacques is not feasible at GC2 during the preliminary permit comment process. The Department agrees with the determination.

3.1.6: Adsorption Process (Amine Treatment)

The adsorption process uses an amine solution to remove H_2S from the sour gas. The sour gas goes through a packed tower containing an amine solution that absorbs the H_2S. A reboiler heats the H_2S-laden amine is heated and routes it to a still column to regenerate the amine. The process also generates an acid gas containing H_2S. The acid gases must be disposed off or routed to a H_2S scavenging system, LO-CAT, or Thiopaq process for sulfur recovery. The adsorption process can achieve a H_2S removal efficiency of 96 percent or greater and reduce H_2S concentration in the fuel gas to 4-10 ppmv.

Common amine solutions used are monoethanoliamine and diethanolamine. Other amines are available and may be blended to enhance performance in specialized applications. The amine solutions absorb other sulfur compounds from the fuel gas. Since the method of control is a 2-step process that involves adsorption followed by H_2S scavenging or the LO-CAT, which the Department determined as not cost-effective, the Department discarded it as not cost-effective. BPXA also determined the adsorption process is not feasible or cost effective at GC2.

3.1.7: Oxidation Process (Xergy Advanced Catalytic Technology)

The Xergy Advanced Catalytic Technology is a dry gas phase direct oxidation of H_2S to elemental sulfur and water. The process operates like a catalytic reactor in a traditional large-scale sulfur recovery plant (Clause process). The fuel gas is heated to reaction temperature after which air is added just before the mixture enters the fixed bed catalytic reactor. The oxidation occurs as follows:

$$2\ H_2S + O_2 \rightarrow 2\ S + 2\ H_2O$$

An unwanted side reaction that oxidizes the H_2S to SO_2 and H_2O can also occur. Maintaining temperature and oxygen content within certain limits control the unwanted side reaction.

In this process, elemental sulfur stays in the vapor phase. A condenser recovers the sulfur, producing a Claus quality (bright yellow) molten sulfur. The process can be applied at pressures ranging from five to 1,000 pounds per square inch gauge.

As part of the BACT analysis for the Central Gas Facility, Xergy informed BPXA that Xergy has not applied the technology to large applications due to high costs associated with fabricating the required customized equipment. The Xergy process has significant safety concerns because it requires introducing oxygen upstream of the catalyst for proper operation. To avoid explosion of the fuel gas stream, the introduction of the oxygen must be precisely controlled. Therefore, Xergy technology is not feasible for EU 5 at GC2.

During the current BACT process BPXA was not able to contact XERGY either by e-mail or phone. Therefore, BPXA did not consider it as an available technology in their BACT review for the GC2 application. There is also reason to believe that this technology is no longer commercially available.

3.1.8: H_2S Seawater Scrubbing

In this process, fuel gas and seawater pass through a tower in which the fuel gas scrubs oxygen from the seawater and the seawater scrubs H_2S from the fuel gas. In the process of de-aerating the seawater, the seawater strips the fuel gas of H_2S. This technology is potentially a feasible method of reducing H_2S in the inlet fuel gas where seawater is readily available. BPXA reviewed this technology as potential BACT based on a similar May 2004 BACT analysis conducted by ConocoPhillips Alaska, Inc. for the Kuparuk Seawater Treatment Plant. In the process of de-aerating the seawater, the fuel gas becomes saturated with seawater. This produced extensive corrosion problems in the piping and burners at Kuparuk Seawater Treatment Plant. A drying system must remove all the water in the fuel gas prior to combustion.

Seawater scrubbing is not technically feasible for controlling SO_2 emissions at GC2 because of corrosion problems and prohibitive costs associated with treatment of seawater.

3.1.9: Good Practices

Fuel sulfur limits have formed the basis of the Department's previous BACT determinations for SO_2 from fuel gas-fired equipment. Therefore, the Department considered it as an option. Limiting the H_2S content of the fuel gas can limit the SO_2 emissions effectively.

3.2: Step 2: Eliminate Technically Infeasible Control Option

Table B-1 summarizes the options for controlling SO_2 emissions from fuel gas combustion.

Table B-1: Control Options for SO_2 Emissions and their Feasibility at GC2

Control Option	Section Discussed	Feasible	Main Reason
Add-on Flue Gas Desulfurization	3.1.1	No	ppmv H_2S in gas is not high enough
Oil Reservoir Biocide Treatment	3.1.2	No	Effectiveness at GC2 unknown
Liquid Redox (LO-CAT)	3.1.3	Yes	Suits characteristics at GC2
H_2S Scavenging	3.1.4	Yes	Suits characteristics at GC2
Thiopaq	3.1.5	No	Line freezing problems in arctic, etc
Shell-Paques Technologies	3.1.5	No	Fuel Gas CO_2 / H_2S ratio too high
Adsorption Process (Amine Treatment)	3.1.6	No	Requires follow-up LO-CAT, etc
Oxidation Process (Xergy ACT)	3.1.7	No	Safety concerns, GC2 too large
H_2S Seawater Scrubbing	3.1.8	No	Corrosion problems
Limit Sulfur in Fuel / Good Practices	3.1.9	Yes	Sulfur emissions low enough to satisfy ambient air quality standards

3.3: Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Table B-2 lists and ranks the remaining technically feasible control technologies in order of effectiveness.

Table B-2: Technically Feasible SO_2 Control Options

Control Technology	Control Efficiency (%)
Liquid Redox (LO-CAT®)	99
H_2S Scavenging (Solid or Liquid)	95
Good Practices	-

3.4: Step 4: Evaluate the Most Effective Controls and Document Results

The Department evaluated cost effectiveness of the control options starting with the most effective controls based on the removal efficiency of the control method. BPXA proposes to revise the H_2S content of the fuel gas burned in EU 5 at GC2 from 25 ppmv to 200 ppmv annual average and emit up to 13.3 tpy SO_2 emissions from EU 5.

Liquid Redox (LO-CAT)

The Department estimates the cost per ton as $45,435 and considers it excessive. Therefore, LO-CAT is not BACT for SO_2 control for EU 5 at GC2. Table B-3 presents the costs and estimated cost effectiveness of LO-CAT.

Table B-3: LO-CAT Costs and Estimated Cost Effectiveness for Control SO_2 Emissions in EU 5

Description of Item and Costs	**BPXA ($)**	**Department ($)**
CAPITAL COSTS		
Equipment Costs		
Basic Equipment and Auxiliaries	257,261	257,261
Instrument and Controls	33,701	33,701
Module Materials	303,568	303,568
Spare Parts	5,145	5,145
Freight	69,460	69,460
Taxes (3 percent of above, excluding freight)	17,990	17,990
Total Equipment Cost (A)	*687,125*	*687,125*
Anchorage Construction Costs		
Erection and Handling	82,323	82,323
Instrumentation	10,290	10,290
Electrical	15,436	15,436
Piping	41,162	41,162
Insulation	2,573	2,573
Painting	2,573	2,573
Total Anchorage Construction Costs (B)	*154,356*	*154,356*
North Slope Construction Costs		
Foundations and Supports	2,573	2,573
Erection and Handling	15,436	15,436
Instrumentation	515	515
Electrical	2,573	2,573

Description of Item and Costs	**BPXA ($)**	**Department ($)**
Piping	7,718	7,718
Insulation	772	772
Painting	515	515
Total North Slope Construction Costs (C)	*30,100*	*30,100*
Total Direct Costs, D (D = A + B + C)	*871,581*	*871,581*
Indirect Costs		
Engineering and Procurement	48,880	48,880
Unit Operator Costs (UOC)	109,961	109,961
Start-up (Included with UOC)	0	0
Performance Test (1.5% of Equipment Costs)	10,307	10,307
License Fee (Vendor Data)	593,000	Included with A
Total Indirect Costs, E	*762,148*	169,148
Total Direct Costs + Indirect Costs, F (F = D + E)	1,633,729	1,040,729
Contingency Costs (30 percent of F), G	*490,119*	*312,219*
Total Capital Costs, H (H = F + G)	*2,123,848*	*1,352,948*
OPERATING COSTS		
Direct Annual Costs		
Operating Labor (730 hours @ $114 per hour)	83,220	83,220
Supervisory Labor (15 percent of operating labor)	12,483	12,483
Maintenance Labor (803 hours @ $114 per hour)	91,542	91,542
Parts and Materials (assumed as 100% of Maintenance)	91,542	91,542
Electricity (8 kW for 8,760 hr/yr @ $0.1 per kWh)	7,008	7,008
Chemicals	1,825	1,825
Desiccant	91,189	91,189
Total Annualized Direct Costs	*378,809*	*378,809*
Indirect Annual Costs		
Overhead Costs included in Operating & Supervisory Labor	----	----
Property Tax (1 percent of Total Capital Costs)	21,238	13,529
Insurance (1 percent of Total Capital Costs)	21,238	13,529
General Administration (2 percent of Total Capital Costs)	42,477	27,059
Capital Recovery (Cost Recovery F * Total Capital Costs)	302,436	166,818
Total Annualized Indirect Costs	*387,389*	*220,935*
Total Annualized Direct and Indirect Operating Costs	*766,198*	*599,744*
Cost Effectiveness for Removing 13.2 tons per year SO_2	**58,045**	**45,435**

Table Notes:
The LO-CAT system assumed to remove 99% of the 13.3 tpy potential SO_2 Emissions
BPXA based 14.24% Cost Recovery Factor based on 7 percent interest and 10-year equipment life
Department based 12.33% Cost Recovery Factor on 4 percent interest and 10-year equipment life

H_2S Scavenging

The Department reviewed the cost estimates for a H_2S scavenging BPXA presented in their BACT analysis included in their application. The Department determined the cost effectiveness for solid scavenging as $64,465 per ton and for liquid scavenging as $49,614 per ton. The cost of removal for the H_2S scavenging system is prohibitive. The Department determined it is not BACT for SO_2 control at GC2.

Table B-4: Solid Scavenger Costs and Cost Effectiveness for Control SO_2 Emissions in EU 5

Description of Item and Costs	**BPXA ($)**	**Department ($)**
CAPITAL COSTS		
Equipment Costs		
Basic Equipment and Auxiliaries	529,423	529,423
Instrument and Controls	69,354	69,354
Module Materials	624,719	624,719
Spare Parts	10,588	10,588
Freight	90,002	90,002
Taxes (3 percent of above, excluding freight)	37,023	37,023
Total Equipment Cost (A)	*1,361,109*	*1,361,109*
Anchorage Construction Costs		
Erection and Handling	169,415	169,415
Instrumentation	21,177	21,177
Electrical	31,765	31,765
Piping	84,708	84,708
Insulation	5,294	5,294
Painting	5,294	5,294
Total Anchorage Construction Costs (B)	*317,654*	*317,654*
North Slope Construction Costs		
Foundations and Supports	5,294	5,294
Erection and Handling	31,765	31,765
Instrumentation	1,059	1,059
Electrical	5,294	5,294
Piping	15,883	15,883
Insulation	1,588	1,588
Painting	1,059	1,059
Total North Slope Construction Costs (C)	*61,942*	*61,942*
Total Direct Costs, D (D = A + B + C)	*1,740,706*	*1,740,706*
Indirect Costs		
Engineering and Procurement	100,590	100,590
Unit Operator Costs (UOC)	226,292	226,292
Start-up	Included with UOC	Included with UOC
Performance Test (1.5% of Equipment Costs)	20,417	20,417
License Fee (Vendor Data)		
Total Indirect Costs, E	*347,299*	*347,299*

Description of Item and Costs	**BPXA ($)**	**Department ($)**
Total Direct Costs + Indirect Costs, F (F = D + E)	2,088,005	2,088,005
Contingency Costs (30 percent of F), G	*626,401*	*626,401*
Total Capital Costs, H (H = F + G)	*2,714,406*	*2,714,406*
OPERATING COSTS		
Direct Annual Costs		
Operating Labor (365 hours @ $114 per hour)	41,610	41,610
Supervisory Labor (15 percent of operating labor)	6,242	6,242
Maintenance Labor (402 hours @ $114 per hour)	45,828	45,828
Parts and Materials (assumed as 100% of Maintenance)	45,828	45,828
Chemicals (SulfaTreat XLP)	48,811	48,811
Media Replacement Labor	49,488	49,488
Media Disposal	40,000	40,000
Desiccant	91,189	91,189
Total Annualized Direct Costs	*368,996*	*368,996*
Indirect Annual Costs		
Overhead Costs included in Operating & Supervisory Labor	0	0
Property Tax (1 percent of Total Capital Costs)	27,144	27,144
Insurance (1 percent of Total Capital Costs)	27,144	27,144
General Administration (2 percent of Total Capital Costs)	54,288	54,288
Capital Recovery (Cost Recovery F * Total Capital Costs)	386,531	334,686
Total Annualized Indirect Costs	*495,107*	*443,262*
Total Annualized Direct and Indirect Operating Costs	*864,103*	*812,258*
Cost Effectiveness for Removing 12.6 tons per year SO_2	**68,580**	**64,465**

Table Notes:
BPXA used a 14.24% Cost Recovery Factor based on 7 percent interest and 10-year equipment life
The Department used a 12.33% Cost Recovery Factor based on 4 percent interest and 10-year equipment life
The H_2S Scavenging system assumed to remove 95% of the 13.3 tpy potential SO_2 Emissions

Table B-5: Liquid Scavenger Costs and Cost Effectiveness for Control SO_2 Emissions in EU 5

Description of Item and Costs	**BPXA ($)**	**Department ($)**
CAPITAL COSTS		
Equipment Costs		
Basic Equipment and Auxiliaries	150,208	150,208
Instrument and Controls	19,677	19,677
Module Materials	177,245	177,245
Spare Parts	3,004	3,004
Freight	25,685	25,685
Taxes (3 percent of above, excluding freight)	10,504	10,504
Total Equipment Cost (A)	*386,323*	*386,323*
Anchorage Construction Costs		

Description of Item and Costs	**BPXA ($)**	**Department ($)**
Erection and Handling	48,066	48,066
Instrumentation	6,008	6,008
Electrical	9,012	9,012
Piping	24,033	24,033
Insulation	1,502	1,502
Painting	1,502	1,502
Total Anchorage Construction Costs (B)	*90,123*	*90,123*
North Slope Construction Costs		
Foundations and Supports	1,502	1,502
Erection and Handling	9,012	9,012
Instrumentation	300	300
Electrical	1,502	1,502
Piping	4,506	4,506
Insulation	451	451
Painting	300	300
Total North Slope Construction Costs (C)	*17,573*	*17,573*
Total Direct Costs, D (D = A + B + C)	*494,019*	*494,019*
Indirect Costs		
Engineering and Procurement	28,539	28,539
Unit Operator Costs (UOC)	64,223	64,223
Start-up (Included with UOC)	0	0
Performance Test (1.5% of Equipment Costs)	5,795	5,795
License Fee (Vendor Data)	---	---
Total Indirect Costs, E	*98,557*	*98,557*
Total Direct Costs + Indirect Costs, F (F = D + E)	592,576	592,576
Contingency Costs (30 percent of F), G	*177,774*	*177,774*
Total Capital Costs, H (H = F + G)	*770,350*	*770,350*
OPERATING COSTS		
Direct Annual Costs		
Operating Labor (365 hours @ $114 per hour)	41,610	41,610
Supervisory Labor (15 percent of operating labor)	6,242	6,242
Maintenance Labor (402 hours @ $114 per hour)	45,828	45,828
Parts and Materials (assumed as 100% of Maintenance)	45,828	45,828
Chemicals (Scavenger @ $736 per day))	268,640	268,640
Desiccant	91,189	91,189
Total Annualized Direct Costs	*499,337*	*499,337*
Indirect Annual Costs		
Overhead Costs included in Operating & Supervisory Labor	0	0
Property Tax (1 percent of Total Capital Costs)	7,704	7,704
Insurance (1 percent of Total Capital Costs)	7,704	7,704

Description of Item and Costs	**BPXA ($)**	**Department ($)**
General Administration (2 percent of Total Capital Costs)	15,407	15,407
Capital Recovery (Cost Recovery F * Total Capital Costs)	109,698	94,984
Total Annualized Indirect Costs	*140,513*	*125,799*
Total Annualized Direct and Indirect Operating Costs	*639,850*	*625,136*
Cost Effectiveness for Removing 12.6 tpy SO2	50,782	49,614

Table Notes:
BPXA used a 14.24% Cost Recovery Factor based on 7 percent interest and 10-year equipment life
The Department used a 12.33% Cost Recovery Factor based on 7 percent interest and 10-year equipment life
The H_2S Scavenging system assumed to remove 95% of the 13.3 tpy potential SO_2 Emissions

Limit Sulfur in Fuel Gas

Limiting SO_2 emissions by requiring fuel gas fired equipment to burn fuel gas with H_2S content low enough to satisfy state emission standards for sulfur compounds is a simple but effective method the Department uses to control SO_2 emissions at several facilities. The annualized cost associated with tracking the fuel content of the fuel gas delivered is negligible. Therefore, a restriction that limits H_2S content of the fuel gas burned to a level that satisfies the state emissions standards is the best option among the control methods discussed in Section 3.2.

3.5: Step 5: Select BACT

The Department researched the RBLC database for similar equipment burning fuel gas. Limiting the H_2S or sulfur content in the fuel gas burned is the control method for the fuel gas burning equipment in the database. The limits were expressed in various forms such as ppmv H_2S, grains of sulfur per cubic foot, or pounds of SO_2 per output power or input energy.

The lowest cost of add-on controls per ton of SO_2 removed is unreasonably high. Therefore, the Department agrees with BPXA that BACT for control of the SO_2 emissions for combustion of fuel gas in EU 5 at GC2 is good practices with no add-on control, based on an annual average 200 ppmv H_2S content of the fuel gas.

Appendix C: Modeling Review Report

Modeling Review Report

State of Alaska
Department of Environmental Conservation
Division of Air Quality

Date: *July 17, 2013*

Project: *BPXA Gathering Center #2 Hydrogen Sulfide (H_2S) Limit Increase*

File No.: *AQ0183MSS03 Revision 1*

Note: This modeling review report supersedes the October 11, 2012 version issued in support of the original Minor Permit AQ0183MSS03. The Department corrected editorial mistakes and provided clarification on select topics, per BPXA request. The Department did not reopen its modeling review, or make any substantive changes. The actual analysis and Department conclusions remain unchanged from those described in the October 11, 2012 version of this modeling review report.

This report summarizes the Department's findings regarding the ambient analysis submitted by BP Exploration (Alaska) Inc. (BPXA) for the revision of fuel gas H_2S limits at Gathering Center #2 (GC2). BPXA submitted this analysis in support of their February 2012 minor permit application (AQ0183MSS03). While the application only triggers minor permit classifications under Article 5 of 18 AAC 50, BPXA provided the ambient demonstrations required under the Prevention of Significant Deterioration (PSD) program in Article 3 of 18 AAC 50. The reasons for these ambient demonstrations are described in the Background section of this report.

The Department finds that BPXA's application adequately complies with the source impact analysis required under 40 CFR 52.21(k), the pre-construction monitoring analysis required under 40 CFR 52.21(m)(1), and the additional impact analysis required under 40 CFR 52.21(o). BPXA's ambient air analysis adequately shows that operating their emission units within the requested constraints will not cause or contribute to a violation of the 1-hour, 3-hour, 24-hour or annual Alaska Ambient Air Quality Standards (AAAQS) for sulfur dioxide (SO_2) provided in 18 AAC 50.010 or the 3-hour, 24-hour or annual maximum allowable increases (increments) for SO_2 provided in 18 AAC 50.020. Particulate matter with an aerodynamic diameter of less than 2.5 microns (PM-2.5) modeling was not required for the reasons described in this report.

BACKGROUND

Project Location and Area Classification

GC2 is located in the Greater Prudhoe Bay Oilfield on Alaska's North Slope. The area is unclassified in regards to compliance with the AAAQS. For purposes of increment compliance, GC2 is located within a Class II area of the Northern Alaska Intrastate Air Quality Control Region. The nearest Class I area, Denali National Park, is located approximately 750 km to the south.

Source/Project Description

GC2 is an existing PSD major source. BPXA is presently operating GC2 under Construction/Operating Permit AQ0183TVP01.

Fuel gas at GC2 has experienced a gradual increase in H_2S content over time due to the H_2S souring of the Prudhoe Bay gas reservoir. As a consequence, the consecutive 12-month average is now approaching the 25 ppmv limits included in permit AQ0183TVP01on Emission Unit (EU) IDs 1, 2, and 5 (Tag Nos. GTRB-02-7000, GTRB-02-7001, and GTRB-02-7704B, respectively). BPXA is requesting the 25 ppmv consecutive 12-month average fuel gas H_2S Best Available Control Technology (BACT) limit in Table 2 under Condition 6 of permit AQ0183TVP01 be rescinded and replaced with a fuel gas H_2S BACT limit of 200 ppmv. BPXA further requests that the 25 ppmv annual average fuel gas H_2S ambient air quality protection limit in Condition 11 of permit AQ0183TVP01 be rescinded and replaced with a fuel gas H_2S limit of 125 ppmv or 185 ppmv dependent upon a corresponding liquid fuel sulfur content.

Ambient Demonstration Requirements

BPXA's application triggers minor permit review under 18 AAC 50.502(c)(3) for SO_2. Per 18 AAC 50.540(c)(2)(A), applicants subject to 18 AAC 50.502(c)(3) must provide an ambient AAAQS analysis for each pollutant for which a permit is required under 18 AAC 50.502(c)(3). BPXA's application also triggers minor permit review under 18 AAC 50.508(6). Per 18 AAC 50.540(k)(3), applicants subject to 18 AAC 50.508(6) must include in their application the effects of revising permit terms and conditions on the underlying ambient demonstration. Therefore, BPXA submitted an AAAQS analysis for SO_2 under 18 AAC 50.540(c)(2)(A) as well as revising the ambient demonstrations previously submitted under the PSD program.

Per 18 AAC 50.306, PSD applicants must essentially comply with the federal PSD requirements in 40 CFR 52.21. The ambient requirements include:

- A "Source Impact Analysis" (aka an ambient AAAQS and increment analysis) for the PSD-triggered pollutants – per 40 CFR 52.21(k),
- An "Air Quality Analysis" (aka preconstruction monitoring data) for the PSD-triggered pollutants – per 40 CFR 52.21(m);
- An "Additional Impact Analyses" – per 40 CFR 52.21(o); and
- A Class I impact analysis (for sources which may affect a Class I area) – per 40 CFR 52.21(p).

In the case of the GC2 Fuel Gas H_2S project, BPXA needed to update their Source Impact Analysis, Air Quality Analysis and Additional Impact Analyses per the November 1987 U.S Environmental Protection Agency (EPA) guidance memorandum *Request for Determination on Best Available Control Technology (BACT) Issues - Ogden Martin Tulsa Municipal Waste Incinerator Facility*. This guidance contains language stating that "…*if a revision to the permit is determined to be appropriate [in order to modify a BACT],the revision must also address all other PSD requirements which may be affected by an allowable increase in permitted…emissions (e.g., protection of the standards and increments, additional impacts, monitoring)*". The 40 CFR 52.21(p) requirement for a Class I impact analysis is not applicable given the substantive distance to the nearest Class I area.

SO_2 emissions are a precursor for PM-2.5. However, a PM-2.5 AAAQS demonstration is not required in this particular case for the following reasons:

1) There is no PM-2.5 permit or modeling trigger in the Department's minor permit program due to precursor emissions; and
2) PM-2.5 was not considered in the original PSD decision and therefore, it is not a consideration under 18 AAC 50.540(k)(3)(C).

The Department further notes that the EPA has not yet provided sufficient tools and guidance to predict the PM-2.5 impacts due to the secondary formation of PM-2.5.

Application Submittal

The Department received BPXA's minor permit application on February 21, 2012. AECOM Environment (AECOM) prepared the minor permit application, including the ambient assessment, on behalf of BPXA. The assessment was reviewed on behalf of the Department by AMEC Environment & Infrastructure, Inc. (AMEC).

AMBIENT AIR POLLUTANT DATA

40 CFR 52.21(m)(1) requires PSD applicants to submit ambient air monitoring data describing the air quality in the vicinity of the project, unless the existing concentration or the project impact is less than the monitoring threshold provided in 40 CFR 52.21(i)(5). The requirement only pertains to the pollutants subject to PSD review. If monitoring is required, the data are to be collected prior to construction. Hence, these data are referred as "pre-construction monitoring" data. Ambient "background" data may also be needed to supplement the estimated ambient impact from the proposed project. BPXA's approach for meeting data needs for pre-construction monitoring requirements and background concentrations is discussed below.

Pre-Construction Monitoring

BPXA collected SO_2 data at the Prudhoe Bay Unit (PBU) Central Compressor Plant (CCP) ambient monitoring station during the 2010 calendar year. The CCP monitoring station is within 10 km of GC2 and located east of GC2 in an area of maximum SO_2 concentrations from large existing sources. The 2010 SO_2 data collected at the CCP monitoring station was accepted and approved by the Department as PSD-quality ambient data and is the most recent data available. The Department therefore accepts the use of the SO_2 data collected at CCP to satisfy the requirements of pre-construction monitoring. The maximum, first-high measured values are shown in Table 1. The Department is reporting the concentrations on a mass basis (micrograms per cubic meter, or $\mu g/m^3$), which is the convention used in modeling, rather than a volumetric basis (parts per million by volume, or ppmv), which is typically used in monitoring reports. The first-high value provides a conservative estimate of the value that could be reported within the form of the ambient standard. The AAAQS is also provided. All of the measured concentrations are well below the AAAQS.

Table 1 – Pre-Construction Monitoring Assessment

Air Pollutant	Avg. Period	Monitored Value* ($\mu g/m^3$)	AAAQS ($\mu g/m^3$)	% of AAAQS
SO_2	Annual	5.2	80	7%
	24-hour	20.9	365	6%
	3-hour	26.1	1300	2%
	1-hour	27.8	196	14%

* Monitored values represent the maximum, first-high value

Background Concentrations

In addition to the pre-construction monitoring requirements for PSD pollutants, ambient "background" data may also be needed to supplement the ambient impact analysis. The background concentration represents impacts from sources not included in the modeling analysis. Typical examples include natural, area-wide, and long-range transport sources.

The background concentration must be evaluated on a case-by-case basis for each ambient analysis. Once the background concentration is determined, it is added to the modeled concentration to estimate the total ambient concentration. Hence, background concentrations are typically needed for all air pollutants included in an AAAQS compliance demonstration, regardless of whether or not PSD pre-construction monitoring is required.

BPXA used 1-hour, 3-hour, 24-hour, and annual concentrations of SO_2 measured at their PBU Drill A Pad (A Pad) monitoring station, located approximately 6.4 kilometers southeast of GC2, during calendar years 2006 through 2010 to represent background concentrations. Some of the concentrations likely include impacts from temporary drilling and well support operations that occurred on the pad during the monitoring effort; this is why some of the values are larger than what BPXA measured at CCP. The A Pad data is therefore a conservative estimate of the background concentration that occurs at GC2. The SO_2 data collected at A Pad for each of these monitoring years was previously accepted and approved as PSD-quality by the Department. Background concentrations, as derived by BPXA, are presented in Table 2. The method used to derive the background concentration for each averaging period are stated in the footnotes for Table 2 and represent the most conservative value for each of the averaging periods listed. The method used to derive the 1-hour SO_2 background concentration is a deviation from the most recent EPA guidance provided in the March 24, 2011 memorandum, "Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards" and the March 1, 2011 memorandum, "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard." These memoranda specify that the 1-hour SO_2 background concentration may be computed based on the 99th-percentile of the annual distribution of daily maximum 1-hour values averaged across the most recent three years of monitored data, irrespective of the meteorological data period used in the dispersion modeling. Though BPXA based their 1-hour SO_2 background concentration on the most recent five years of data, the concentration derived by BPXA is more conservative than a comparable value based on the most recent three years due to significantly higher monitored values of SO_2 in 2006 and 2007. Therefore, the Department accepts the background SO_2 concentrations derived by BPXA presented in Table 2.

Table 2 – Background Concentrations

Air Pollutant	Avg. Period	Background Concentration[1] (μg/m^3)
SO_2	Annual[2]	4.1
	24-hour[3]	37
	3-hour[3]	43
	1-hour[4]	25

[1] Based on measurements taken at A Pad during calendar years 2006 through 2010
[2] Highest annual average concentration across all years analyzed.
[3] Maximum block average concentration across all years analyzed.
[4] The 99th-percentile of the annual distribution of daily maximum 1-hour values averaged across all years analyzed.

SOURCE IMPACT ANALYSIS

BPXA used computer analysis (modeling) to predict the ambient SO_2 air quality impacts. AECOM conducted the modeling analyses on behalf of BPXA. The Department's findings regarding BPXA's analyses are provided below.

Approach

BPXA proposed three separate GC2 operating scenarios. Based on previous modeling conducted for GC2, BPXA assumed that impacts from project emissions will exceed the modeling significance levels (SILs) listed in Table 5 of 18 AAC 50.215(d). Therefore, impacts were assumed to be significant, and a significant impact analysis was not conducted. To demonstrate compliance with the AAAQS and PSD Class II increments, BPXA conducted a cumulative impact analysis and a PSD increment analysis for SO_2. In addition, BPXA conducted a culpability analysis to demonstrate that limits established as a result of this analysis should not require short-term monitoring, recordkeeping and reporting (MR&R).

Cumulative Impact Analysis
Compliance with the AAAQS was determined based on the total estimated air quality concentration, which is the sum of the following:

- Modeled ambient impacts resulting from all GC2 emission units modeled at the proposed allowable emission rates for each of the three operating scenarios considered;
- Modeled ambient impacts from offsite sources; and
- Background concentrations from non-modeled sources.

BPXA included off-site sources likely to cause a significant concentration gradient in the vicinity of the GC2 sources under consideration. Off-site sources included in the cumulative impact analysis for GC2 included major stationary sources located within the PBU, Northstar Unit, Duck Island Unit (DIU), Kuparuk River Unit (KRU), Milne Point Unit (MPU), and Deadhorse. BPXA's approach for modeling off-site sources is described in Attachment IV of their application which includes a complete inventory of off-site sources modeled. The results of the cumulative impact analysis are presented in Table 5.

In addition to the requested permit revisions on H_2S limits at GC2, BPXA is simultaneously requesting similar revisions to H_2S limits at Gathering Center #1 (GC1), Gather Center #3 (GC3), and Flow Station #2 (FS2). Each of these sites is included as an off-site source in each of the GC2 operating scenarios. The modeling protocol included in Attachment IV of the application indicates SO_2 emissions for GC1, GC3, and FS2 would be modeled using anticipated worst-case SO_2 potential to emit following fuel gas H_2S increases.

In summary, BPXA's modeling approach for the SO_2 cumulative impact analysis is acceptable.

Increment Analysis

The SO_2 baseline date for the Northern Alaska Intrastate Air Quality Control Region is June 1, 1979. There are both baseline and increment consuming emission units at GC2. For this analysis, emission units with an unknown installation date were assumed to consume SO_2 increment. All off-site emission units were assumed to be 100% SO_2 increment consuming.

BPXA's approach for modeling the SO_2 increment consumption is described in Attachment IV of their application. The results of the increment analysis are presented in Table 6. In summary, BPXA's approach for modeling the SO_2 increment is acceptable.

Model Selection

There are a number of air dispersion models available to applicants and regulators. The EPA lists these models in their *Guideline on Air Quality Models* (Guideline), which the Department has adopted by reference in 18 AAC 50.040(f). BPXA used EPA's AERMOD Modeling System (AERMOD) for the ambient analyses. AERMOD is an appropriate modeling system for this application.

The AERMOD Modeling System consists of three components: AERMAP (used to process terrain data and develop elevations for the receptor grid/emission units), AERMET (used to process the meteorological data), and the AERMOD dispersion model (used to estimate the ambient concentrations). BPXA used the version of AERMET (version 11059) and AERMOD (version 11103) current at the time of the submission. Due to the characteristic flat terrain in and around the PBU and lack of any significant terrain features, AERMAP was not required for this modeling analysis.

EPA has subsequently released AERMOD version 12060. The Department generally does not make applicants update their permit applications if there is a subsequent model change. The Department nevertheless evaluated the potential effects of the changes and found them to be innocuous. Therefore, BPXA's use of AERMOD version 11103 is acceptable.

Meteorological Data

AERMOD requires hourly meteorological data to estimate plume dispersion. According to the Guideline, a *minimum* of one-year of site-specific data, or five years of representative National Weather Service (NWS) data should be used. When modeling with site-specific data, the Guideline states that additional years (up to five) should be used when available to account for year-to-year variation in meteorological conditions.

BPXA used five years of site-specific data collected at the PBU A Pad from 2006 through 2010. The 2006 through 2010 meteorological data sets were accepted and approved by the Department as PSD-quality with the exception failing to meet the quarterly data capture requirements for the 2-meter, 10-meter, temperature difference, and solar radiation measurements, in varying combinations, in the 2006, 2007, and 2008 data sets. As a result, the Department prescribed an approach for filling these data gaps using cloud cover and temperature data collected at the Deadhorse National Weather Service (NWS) station. The procedures for data substitution are adequately described in Attachment IV of the application. The Department notes that data substitution was not required for the 2009 and 2010 meteorological data. The Department has reviewed the A Pad raw and processed meteorological data files for the 2006 through 2010 period, as well as the interim files created while performing the data substitution for 2006 through 2008 using NWS data collected at Deadhorse. The Department accepts the processed 2006 through 2010 meteorological data files prepared for use with AERMOD.

AERMET requires the area surrounding the meteorological tower to be characterized in regards to the following three surface characteristics: noon-time albedo, Bowen ratio, and surface roughness length. EPA has provided additional guidance regarding the selection and processing of these values in their *AERMOD Implementation Guide*.

BPXA derived their domain specific surface parameters using the tundra values previously approved by the Department for North Slope sources. Individual parameter values are assigned by month in order to adjust the surface characteristics according to each season. The Department agrees with BPXA's methodologies which observe guidance provided by both EPA and the Department in calculating surface parameters. The accepted values are illustrated in Table 3.

Table 3 – Approved AERMET Surface Parameters for PBU A Pad

Surface Parameter	Winter Value	Summer Value
Albedo	0.8	0.18
Bowen Ratio	1.5	0.80
Surface Roughness Length	0.004	0.02

For purposes of the A Pad AERMET surface parameters, summer is defined as June through September, and winter is defined as October through May.

EPA generally allows applicants to use modeled concentrations that are consistent with the form of the standard or increment if at least one year of representative site-specific, or five years of representative NWS data are used. When these criteria are not met, then applicants must use the highest modeled concentration. In all cases, applicants must compare the highest modeled concentration to the deterministic annual average standards/increments, SILs, and all pre-construction monitoring thresholds.

The Department allowed BPXA to compare the high second-high (H2H) concentration to the short-term deterministic AAAQS/increments since they used site-specific data. The Department allowed BPXA to compare the five year average of the high fourth-high (H4H) of the annual distribution of the maximum daily one hour concentrations to the 1-hour SO_2 standard. The H4H is a surrogate for the 99th percentile, which is what the standard is based on.

Emission Unit Inventory

BPXA modeled the emission units listed in permit AQ0183TVP01. Emission units within GC2 include gas and liquid fired turbines for power generation and gas compression, internal combustion engines for emergency power generation and fire water pumping, large process heaters and boilers, and flares. The unit locations are shown in Figure 2-3 and Figure 2-4 of Attachment IV of their permit application.

Emission Rates

The assumed emission rates and stack parameters have significant roles in an ambient demonstration. Therefore, the Department checks these parameters very carefully. The Department found the modeled emission rates to be consistent with the emissions information provided throughout the application.

SO_2 Emissions

SO_2 emissions are directly related to the amount of sulfur in the fuel. The sulfur in fuel gas is in the form of H_2S. The sulfur in liquid fuel (e.g., diesel) is in the form of elemental sulfur. BPXA's emission units consist of both liquid and gas fired units. BPXA proposed and modeled three operating scenarios that represent different fuel gas H_2S content and corresponding liquid fuel sulfur content, in addition to varying the type of fuel burned in dual fuel-fired units. Each of the three operating scenarios is described below and summarized in Table 4. The Department treated all H_2S and fuel sulfur contents as not-to-exceed values in order to protect the short-term and annual average standards and increments.

The first scenario, identified by BPXA as "Regular Sulfur Liquid Fuel," represents a 125 ppmv fuel gas H_2S content for all fuel gas-fired and dual fuel-fired emission units at GC2 with the exception of EU IDs 5 and 36 which were modeled at 200 ppmv fuel gas H_2S. For this scenario the liquid fuel sulfur content is limited to 0.11 wt% for all liquid fuel-fired emission units at GC2.

The second scenario, "Ultra Low Sulfur Liquid Fuel," represents an increase in the H_2S content to 185 ppmv for all fuel gas-fired and dual fuel-fired emission units at GC2 with the exception of EU IDs 5 and 36 which were modeled at 200 ppmv fuel gas H_2S. For this scenario the liquid fuel sulfur content is limited to 0.0015 wt%, also known as Ultra Low Sulfur Diesel (ULSD), for all liquid fuel-fired emission units at GC2.

Scenario three, “Dual Fuel Fired Heaters,” represents a 125 ppmv fuel gas H_2S content for all fuel gas-fired emission units at GC2 with the exception of EU IDs 5 and 36 which were modeled at 200 ppmv fuel gas H_2S. In addition, the seven dual fuel-fired emission units (EU IDs 9, 10, 11, 12, 13, 14, and 15) were modeled burning liquid fuel. The liquid fuel sulfur content was limited to 0.11 wt% for all liquid fuel-fired and dual fuel-fired emission units at GC2.

EUs 18 through 24 at GC2 are emergency units that BPXA operates on an intermittent basis for testing and maintenance. BPXA modeled these EUs assuming continuous operations. Average hourly emission rates were used to demonstrate compliance with the 1-hour probabilistic SO_2 AAAQS, consistent with EPA’s recommendations as presented in the March 1, 2011 clarification memorandum referenced previously in this report. BPXA used maximum emission rates to demonstrate compliance with the 3-hour and 24-hour deterministic SO_2 AAAQS.

Table 4 – GC2 Operating Scenarios

Scenario	**Fuel Gas H_2S Content[*] (ppmv)**	**Liquid Fuel Sulfur Content (wt%)**	**Fuel Type (Dual Fuel-Fired Units)**
Regular Sulfur Liquid Fuel	125	0.11	Fuel Gas
Ultra Low Sulfur Liquid Fuel	185	0.0015	Fuel Gas
Dual Fuel-Fired Heaters	125	0.11	Liquid Fuel

[*] EU IDs 5 and 36 were modeled at 200 ppmv fuel gas H_2S for each of the GC2 operating scenarios.

Stack Parameters

The assumed stack parameters (stack height, stack diameter, exit velocity and exhaust temperature) have significant roles in an ambient demonstration. Therefore, the Department checks these parameters very carefully. The Department found the modeled stack parameters to be consistent with the vendor information or expectations for similarly sized EUs.

Horizontal/Capped Stacks

The presence of non-vertical stacks or stacks with rain caps requires special handling in an AERMOD analysis. The proper approach for characterizing a horizontal/capped stack is described in EPA’s *AERMOD Implementation Guide*. For capped and horizontal stacks subject to building downwash, the user should input the actual stack diameter and exit temperature, but set the exit velocity to a nominally low value (0.001 m/s). If the capped/horizontal stack is *not* subject to downwash, then the 0.001 m/s exit velocity should be used along with an artificially large diameter (set to maintain the actual exhaust flow rate). Minor adjustments to the stack height may also be warranted.

EPA has developed a non-default option in AERMOD that will revise the stack characteristics as warranted for stacks that are identified as capped or horizontal. EPA Region 10 granted the Department permission to use this option in general in October 2007.[1] BPXA used this non-default option to characterize their capped/horizontal stacks.

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[1] E-mail from Herman Wong (EPA R10) to Alan Schuler (ADEC); *RE: Capped/Horizontal Stack Issue*; October 2, 2007.

Ambient Air Boundary

For purposes of air quality modeling, “ambient air” means outside air to which the public has access. Ambient air typically excludes that portion of the atmosphere within a stationary source’s boundary. BPXA used the gravel pad edge as the ambient air boundary. This is an appropriate boundary for North Slope sources.

Receptor Grid

BPXA used Cartesian receptor grids of varying resolution centered on GC2 as follows:

- 25-meter resolution along the edge of the gravel pad (ambient air boundary);
- 25-meter resolution within 100 meters of the ambient air boundary;
- 100-meter resolution extending 1 kilometer in each cardinal direction from the facility; and
- 250-meter resolution to a distance of 2 kilometers in each cardinal direction from the facility.

Due to the characteristic flat terrain in around the PBU, all receptor elevations and hill heights were set to zero (0.0) meters. BPXA’s receptor grids are acceptable.

Downwash

Downwash refers to conditions where nearby structures influence plume dispersion. Downwash can occur when a stack height is less than a height derived by a procedure called “Good Engineering Practice,” as defined in 18 AAC 50.990(42). The modeling of downwash-related impacts requires the inclusion of dimensions from nearby buildings.

EPA has established specific algorithms for determining which buildings must be included in the analysis and for determining the profile dimensions that would influence the plume from a given stack. EPA has incorporated these algorithms into the “Building Profile Input Program” (BPIP) computer program. BPXA used EPA’s PRIME version of BPIP (BPIPPRM, version 04274) to determine the building profiles needed by AERMOD. This is an appropriate version of BPIP.

RESULTS AND DISCUSSION

The maximum SO_2 AAAQS impacts for each operating scenario summarized in Table 4 are shown in Table 5. The background concentrations, total impacts and ambient standards are also shown.

Table 5 – Maximum SO_2 AAAQS Impacts by Operating Scenario

Operating Scenario	Avg. Period	Maximum Modeled Conc (µg/m^3)	Bkgd Conc (µg/m^3)	TOTAL IMPACT: Max conc plus bkgd (µg/m^3)	Ambient Standard (µg/m^3)
Regular Sulfur Liquid Fuel[1]	1-hr	70	25	95	196
	3-hr	82	43	125	1,300
	24-hr	56	37	93	365
	Annual	5.5	4.1	9.6	80
Ultra Low Sulfur Liquid Fuel[2]	1-hr	81	25	106	196
	3-hr	87	43	130	1,300
	24-hr	46	37	83	365
	Annual	7.4	4.1	11.5	80
Dual Fuel-Fired Heaters[3]	1-hr	70	25	95	196
	3-hr	221	43	264	1,300
	24-hr	117	37	154	365
	Annual	6.3	4.1	10.4	80

[1] 125 ppmv Fuel Gas H_2S (except EU IDs 5 and 36 modeled at 200 ppmv fuel gas H_2S) and 0.11 wt% Liquid Fuel Sulfur (dual fuel-fired heaters burning fuel gas)

[2] 185 ppmv Fuel Gas H_2S (except EU IDs 5 and 36 modeled at 200 ppmv fuel gas H_2S) and 0.0015 wt% Liquid Fuel Sulfur (dual fuel-fired heaters burning fuel gas)

[3] 125 ppmv Fuel Gas H_2S (except EU IDs 5 and 36 modeled at 200 ppmv fuel gas H_2S) and 0.11 wt% Liquid Fuel Sulfur (dual fuel-fired heaters burning liquid fuel)

The maximum SO_2 increment impacts are shown in Table 6, along with the Class II increments. All of the maximum impacts are less than the applicable Class II increments.

Table 6 – Maximum SO_2 Increment Impacts by Operating Scenario

Operating Scenario	Avg. Period	Maximum Modeled Conc (μg/m^3)	Class II Increment Standard (μg/m^3)
Regular Sulfur Liquid Fuel[1]	3-hr	81	512
	24-hr	41	91
	Annual	5.5	20
Ultra Low Sulfur Liquid Fuel[2]	3-hr	87	512
	24-hr	46	91
	Annual	7.4	20
Dual Fuel-Fired Heaters[3]	3-hr	171	512
	24-hr	71	91
	Annual	3.7	20

[1] 125 ppmv Fuel Gas H_2S (except EU IDs 5 and 36 modeled at 200 ppmv fuel gas H_2S) and 0.11 wt% Liquid Fuel Sulfur (dual fuel-fired heaters burning fuel gas)

[2] 185 ppmv Fuel Gas H2S (except EU IDs 5 and 36 modeled at 200 ppmv fuel gas H_2S) and 0.0015 wt% Liquid Fuel Sulfur (dual fuel-fired heaters burning fuel gas)

[3] 125 ppmv Fuel Gas H_2S (except EU IDs 5 and 36 modeled at 200 ppmv fuel gas H_2S) and 0.11 wt% Liquid Fuel Sulfur (dual fuel-fired heaters burning liquid fuel)

EPA allows applicants to compare the impact to the form of the standard. All of the standards shown in Tables 5 and 6 are deterministic except for the 1-hour SO_2 AAAQS.

BPXA compared the highest overall H2H impact of each modeled year to the short term deterministic standards and the highest overall impact of each modeled year to the annual deterministic standards. BPXA also compared the five year average of the H4H of the daily maximum one hour concentrations to the 1-hour SO_2 standard. BPXA's approach is consistent with EPA guidance and is therefore acceptable.

ADDITIONAL IMPACT ANALYSES

Per 40 CFR 52.21(o), PSD applicants must assess the impact from the proposed project and associated growth on visibility, soils, and vegetation. BPXA provided the additional impact analysis in Section 4.0 of Attachment IV of their application. The Department's findings are reported below.

Visibility Impacts

The typical tool for assessing the potential visibility impact from North Slope sources is EPA's VISCREEN model. According to EPA's *Workbook for Plume Visual Impact Screening and Analysis (Revised)*, the pollutants of concern in a VISCREEN analysis are particulates and nitrogen oxides. SO_2 emissions are not included in the assessment. Therefore, this permit action should not affect the visibility of BPXA's exhaust plumes.

Vegetation Impacts

BPXA compared the modeled impacts to the 3-hour SO_2 secondary air quality standard and an annual sensitivity threshold for lichens. The secondary air quality standards are set to protect public welfare, which includes protection against vegetative damage. As previously shown in Table 5, the maximum SO_2 impact is well below the 3-hour standard. Therefore, the general vegetation should be protected.

Lichens are more sensitive to air pollutants than vascular plants since they lack roots and derive all growth requirements from the atmosphere. Some lichen species are adversely affected when the annual average SO_2 concentration ranges between 13 to 26 $\mu g/m^3$.[2] While it is not known whether lichens in the Prudhoe Bay area have this same sensitivity, these values provide a surrogate measure of the potential sensitivity threshold.

The maximum annual average SO_2 impact (11.5 $\mu g/m^3$) does not exceed the 13 $\mu g/m^3$ sensitivity threshold. Therefore, the local lichens should not be adversely impacted by the proposed increase in SO_2 emissions.

Soil Impacts

BPXA correctly noted that there is little information available regarding the effects of air pollutants on soils. They also noted that protecting the vegetative cover helps protect the soil. Since the air quality impacts are below the applicable vegetation thresholds, the soil should likewise be protected. BPXA's conclusions are reasonable.

Secondary Impacts

40 CFR 52.21(o)(2) requires PSD applicants to assess the impacts from general commercial, residential, industrial and other growth associated with the source or modification. This project only involves an increase in emissions resulting from increasing the fuel gas H_2S concentration and does not involve physical modification to the stationary sources or a change in source throughput. Therefore, BPXA does not expect growth will occur due to the project. The Department accepts BPXA's assessment.

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[2] *Air Quality Monitoring on the Tongass National Forest* (USDA – Forest Service; September 1994).

CONCLUSION

The Department reviewed BPXA's modeling analysis for the GC2 Fuel Gas H_2S Limit Revision, subject to the full rigor of PSD review as discussed at the beginning of this document, and concluded the following:

1. BPXA's application and supplemental information adequately complies with the source impact analysis required under 40 CFR 52.21(k) ***Source Impact Analysis***. BPXA has adequately demonstrated that the SO_2 emissions associated with operating the stationary source within the requested operating limits will not cause or contribute to a violation of the 1-hour, 3-hour, 24-hour and annual average SO_2 AAAQS provided in 18 AAC 50.010 or the SO_2 3-hour, 24-hour, and annual average SO_2 maximum allowable increases (increments) provided in 18 AAC 50.020. BPXA's modeling analysis also fully complies with the showing requirements of 18 AAC 50.540(c)(2) and 18 AAC 50.540(k)(3).
2. BPXA appropriately used the models and methods required under 40 CFR 52.21(l) ***Air Quality Models***.
3. BPXA adequately complies with the pre-application air quality analysis required under 40 CFR 52.21(m)(1) ***Preapplication Analysis***.
4. BPXA's application adequately complies with the additional visibility, soils, vegetation and secondary impact analysis required under 40 CFR 52.21(o) ***Additional Impact Analysis***.
5. BPXA's application adequately complies with the applicable minor permit application requirements in 18 AAC 50.540(c)(2) and 18 AAC 50.508(6).

The Department has developed conditions in Minor Permit AQ0183MSS03 Revision 1 to ensure BPXA complies with the ambient air quality standards and increments. These conditions are summarized below:

1. To protect the 1-hour, 3-hour, 24-hour and annual average SO_2 AAAQS and the 3-hour, 24-hour, and annual average SO_2 increments the Permittee must comply with the gas fuel H_2S and liquid fuel sulfur limits listed in Table 4.

2. To protect the 1-hour[3] and annual average SO_2 AAAQS and the annual average increment the Permittee must comply with the existing 200 hour per year limit on EU IDs 18 through 24.

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[3] An annual limit to protect the 1-hour probabilistic standard is imposed in accordance with the 1 March, 2011 EPA clarification memorandum. It is referenced in the *SO_2 Emissions* section that details short-term emissions averaging.