ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR PERMITS PROGRAM

TECHNICAL ANALYSIS REPORT

Air Quality Control Minor Permit AQ0182MSS02
BP Exploration (Alaska) Incorporated
Gathering Center #1

HYDROGEN SULFIDE LIMIT INCREASE PROJECT

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Preliminary – August 3, 2012

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ABBREVIATIONS/ACRONYMS

Acronyms

AAC	Alaska Administrative Code
Department	Alaska Department of Environmental Conservation
BACT	Best Available Control Technology
BPXA	BP Exploration (Alaska) Incorporated
CFR	Code of Federal Regulations
EPA	Environmental Protection Agency
EU	Emission Unit
GC1	Gathering Center Number 1
ISO	International Standards Organization
LHV	Lower Heating Value
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	pounds
lb/ton	pound 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
NOx	Oxides of Nitrogen
PM-10	Particulate Matter with a nominal 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 AQ0182MSS02 to BP Exploration (Alaska) Incorporated (BPXA) for their Greater Prudhoe Bay Gathering Center #1 (GC1). The Department is issuing AQ0182MSS02 under 18 AAC 50.508(6) to revise conditions established in a Title I permit. The Department will incorporate AQ0182MSS02 into GC1's operating permit by administrative amendment.

1.1 Stationary Source Description

BPXA is the Permittee, owner, and operator of GC1, a crude petroleum and natural gas production facility. The Standard Industrial Classification for GC1 is 1311 and the North American Industrial Classification System code is 211111. GC1 has operated at its current location since 1978. GC1 processes crude oil fluids received from various locations on the North Slope, including Well Pads D, E, F, G, K, Y, and P of the Western Operating Area. GC1 can process more than 300,000 barrels of crude oil and 2.5 billion standard cubic feet of gas per day.

GC1 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 GC1. GC1 processes the water to remove entrained crude oil before injection into wells. Energy required for the Central Power station and to support operations comes primarily from combustion of produced fuel gas.

GC1 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). GC1 is not a hazardous air pollutants (HAPs) major source because it emits less than 10 tpy of any HAP or 25 tpy of total HAPs. BPXA currently operates GC1 under an application shied. Table A-1 of Appendix A presents the equipment at GC1.

1.2 Brief Hydrogen Sulfide (H_2S) Limit History

The Department and United States Environmental Protection Agency (EPA) have issued numerous permits for GC1 and had several discussions with BPXA on H_2S content in fuel gas burned at GC1. BPXA has worked with EPA to clarify and revise permit conditions in the PSD permits issued by EPA. EPA and BPXA copied the Department on all correspondence regarding the revisions. The revisions led to an overall decrease in emissions on a ton per year (tpy) basis, except SO_2. The Department issued Permit-to-Operate 9673-AA010 for GC1 on August 17, 1981. The permit revised the tpy SO_2 Best Available Control Technology (BACT) limit established in the EPA PSD permit and increased the H_2S content of the fuel gas burned from 20 ppmv to 25 ppmv. The Department carried forward the H_2S BACT limit in Permit-to-Operate 9673-AA010 into Permit-to-Operate 9673-AA003 issued on January 16, 1997 and AQ0182TVP01 issued in 2003.

Permit-to-Operate 9673-AA003 contained an air quality protection condition that limited the H_2S content of fuel gas burned in EUs 6, 7, and 8 to 25 ppmv annual average with an option to increase it to 125 ppmv after conducting a modeling analysis. The condition required BPXA to monitor the H_2S content of the fuel gas burned in the EUs monthly. The Department incorporated the condition into AQ0182TVP01 Revision 2 issued on August 26, 2005.

2.0 Application Description

The Department received the application on March 5, 2012. BPXA is requesting an increase in the H_2S limit in the fuel gas burned by EUs 6, 7, and 8. Because the Prudhoe Bay gas reservoir has soured over time, the H_2S content of the fuel gas burned has gradually increased to the point where BPXA cannot maintain continuous compliance with Condition 6 and Condition 13 of AQ0182TVP01 Revision 2. Condition 6 limits the H_2S content of fuel gas burned in EUs 6, 7, and 8 to 25 ppmv. Condition 13 limits the H_2S content of fuel gas burned in EUs 6, 7, and 8 to 25 ppmv with an option to increase it to 125 ppmv upon Department approval of an air quality modeling analysis that supports the higher limit. Condition 13 also requires monthly monitoring of the H_2S content of the fuel gas burned in the EUs. BPXA submitted the application assuming Condition 6 of AQ0182TVP01 is an SO_2 BACT limit and Condition 13 is an ambient limit.

BPXA's 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. BPXA's specific requests are:

- Revise the 25 ppmv annual average fuel gas H_2S BACT limit in Condition 6 of AQ0182TVP01 for EUs 6, 7, and 8 to 200 ppmv;
- Revise the 25 ppmv annual average fuel gas H_2S limit in Condition 13 of AQ0182TVP01 to 200 ppmv for EUs 6 through 8;
- For all other gas-fired EUs (or dual-fired EUs while burning gas), revise the 25 ppmv annual average fuel gas H_2S limit in Condition 13 of AQ0182TVP01 to:
    - 125 ppmv when the liquid fuel sulfur content exceeds 15 parts per million by weight (ppmw); or
    - 200 ppmv when the liquid fuel sulfur content does not exceed 15 ppmw;
- Limit the sulfur content of liquid fuel to 0.11 weight percent 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 of SO_2 emissions as required by 40 CFR 52.21(r)(6) to ensure that increase in SO_2 emissions resulting from the revisions do not exceed 40 tpy; and
- Amend AQ0182TVP01 using the procedure specified at 18 AAC 50.542(e).

3.0 Emissions Calculations

The project does not increase emissions of any pollutant except SO_2. BPXA used the baseline actual fuel gas consumption and baseline actual H2S content of the fuel gas to estimate the baseline actual SO_2 emissions as 20.5 tpy. Similarly, they used projected future fuel consumption of fuel gas and projected future H_2S content in the fuel gas to estimate projected emissions as 58.7 tpy. Appendix B presents actual SO_2 emissions. The PSD analysis does not include emissions from liquid-fired EUs because BPXA does not propose to increase the sulfur content of the liquid fuel currently burned.

3.1 Project SO_2 Emissions, Permit Applicability, and Assessable Emissions

Table 1 presents the potential-to-emit (PTE) and permit applicability for the project. Assessable emissions are 6,523 tpy.

Table 1 – PTE at GC1, Permit Applicability, and Assessable Emissions (tpy)

Description	**NO_x**	**CO**	**PM-10**	**SO_2**	**VOC**	**Total**
Facility-wide PTE before Modification	4,912	1,374	107	48	44	6,485
Baseline Actual SO_2 Emissions from Fuel Gas				20.5		
Future Actual SO_2 Emissions from Fuel Gas				58.7		
Increase in Emissions due to Project	0	0	0	38.2	0	
PSD Triggered?	No	No	No	No	No	
18 AAC 50.502(c)(3) triggered?	No	No	No	Yes	No	
PTE after Modification (Existing PTE plus Increase)	4,912	1,374	107	86	44	
Assessable Emissions	4,912	1,374	107	86	44	6,523

Table Notes:
Emissions for SO_2 obtained from Appendix B of this TAR.
PTE before modification obtained from Table A, AQ0182TVP01 Statement of Basis and AirTools as of 6/18/2012.

3.2 Department Findings

The Department finds that:

1. GC1 is classified as a PSD major stationary source under 40 CFR 52.21(b)(1)(i) because it has the ability to emit more than 250 tpy of one or more pollutants. GC1 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 project increases actual SO_2 emissions at an existing facility by more than 10 tpy.
4. Condition 6 of AQ0182TVP01 Revision 2 describes the current 25 ppmv annual average H_2S limit of fuel gas burned in EU, 6, 7, and 8 as BACT. Therefore, BPXA must submit a revised BACT analysis to increase the H_2S limit for fuel gas burned in EUs 6, 7, and 8.
5. Condition 13 of AQ0182TVP01 Revision 2 describes the 25 ppmv annual average H_2S limit of fuel gas burned in EUs 6, 7, and 8 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 6, 7, and 8.
6. Since the actual baseline SO_2 emissions for GC1 is 20.5 tpy from all fuel gas-burning EUs at GC1, future actual emissions from all fuel gas-burning EUs must be less than 60.5 tons per 12 consecutive months to avoid triggering PSD permit requirements.

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.

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 Section 7 of the permit.

As required under 18 AAC 50.544(a)(6), Section 4 of AQ0182MSS02 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 accommodated 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 6 and Condition 13 of Operating/Construction Permit AQ0182TVP01 Revision 2 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 established in this permit action.

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

AQ0182MSS02 revised the existing fuel gas H_2S BACT limit from 25 ppmv annual average to 200 ppmv at any time.

In assessing the BACT revision request, the Department followed U.S. EPA guidance memo dated November 19, 1987[1] 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 productions 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.

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

4.3 Requirements under 40 CFR 52.21(r)(6)

BPXA is using the provisions under 40 CFR 52.21(r)(6) to avoid a PSD modification. They have projected the fuel gas H_2S content will not exceed 70 ppmv within the next 10 years based on the past 10 years of recordkeeping. Using this 70 ppmv upper estimate and the quantity of fuel gas burned at the source, the increase in SO_2 emissions from the requested changes will be less than 40 tpy. Since the projected 38.2 tpy SO_2 emissions increase could exceed 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 ensure that the emission increases will be less than 40 tpy. In order to ensure that the increase in SO_2 emissions at the source will be less than 40 tpy, the Department has included an emission limit of 60.5 tpy. The Department derived this limit from the baseline actual emissions in Table 1 and allowable increase of 39 tons (with one-ton margin of compliance). Section 6 of the permit contains the limit and the monitoring and recordkeeping requirements for tracking SO_2 emissions to demonstrate compliance with the annual emission limits.

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

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

Where:

tons SO_2 = 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 normal temperature and pressure.
2000 lb = 1 ton

Since limitations on the operating hours also enable the stationary source to avoid PSD, the Department carried over operating hour limits in Section 5 (Source-Specific Requirements) of the Air Quality Operating / Construction Permit AQ0182TVP01 Revision 2 to the minor permit. The operating hour requirements are in Section 6 of the minor permit.

4.4 SO_2 BACT Analysis

BPXA submitted a SO_2 BACT analysis for the H_2S content of the fuel gas burned in EUs 6, 7, and 8 because they are requesting to revise an existing BACT. The Department reviewed BPXA's SO_2 BACT analysis for EUs 6, 7, and 8. The Department determined that the revised SO_2 BACT for EUs 6, 7, and 8 is 200 ppmv H_2S on a not-to-exceed basis (see Section 3, Step 5 of the BACT analysis in Appendix C).

The lowest cost per ton for controlling SO_2 emissions from EU 6, 7, and 8 exceeds \$19,600. The Department agrees with BPXA that the control technologies are not cost effective for GC1. Table 2 presents the calculation of cost effectiveness for controlling SO_2 emissions for the control technologies identified. Appendix C presents the Department's review of the SO_2 BACT analysis for EU 6, 7, and 8.

Table 2: Technically Feasible Control Technology Summary

Control Technology	Annualized Cost		Control Efficiency	Tons Removed	Removal Cost ($/ton	
	BPXA	Department			BPXA	Department
Liquid Redox (LO-CAT)	1,582,482	1,321,905	99	67.4	23,480	19,600
Shell Paques	3,589,480	3,262,472	99	67.4	53,256	48,404
H_2S Solid Scavenger	5,001,417	3,697,295	95	64.7	77,302	57,100
H_2S Liquid Scavenger	2,905,858	2,817,679	95	64.7	44,913	43,500

Table Notes:
Uncontrolled Emission is 68.1 tons per year (tpy)
Annualized costs of the Department taken from Table C-4 through C-6 of the BACT analysis, Appendix C.

5.0 Permit Administration

BPXA is currently operating GC1 under expired Construction/Operating Permit 182TVP01 and a permit shield after applying for operating permit renewal. GC1 does not have any other active Title 1 permits. All of the Title 1 conditions are included in the Construction/ Operating permit. Since this Construction/Operating permit will be replaced with an operating permit renewal, the Department took the opportunity to carry forward all of the active Title 1 conditions into AQ0182MSS02. These Title 1 conditions include the BACT limits for NOx, CO and PM established in previous PSD permit actions by the Department and EPA.

The permit established additional monitoring requirements for liquid fuel sulfur. BPXA requested administrative revision of AQ0182TVP01.

Appendix A: Emission Units at GC1

EU ID	Tag Number	Emission Unit Description	Rating / Size	Installed Date
Group I: Gas –Fired Turbines				
1	GTRB-01-7000	GE MS5352B Compressor	35,000 hp ISO	Prior to 12/81
2	GTRB-01-7001	GE MS5352B Compressor	35,000 hp ISO	Prior to 12/81
5	GTRB-51-3204	Cooper RB211-24C Compressor	33,300 hp ISO	Prior to 12/81
6	GTRB-51-3304		33,300 hp ISO	Prior to 06/81
7	GTRB-01-7704A	Sulzer S3 Pump	7,910 hp ISO	Prior to 06/81
8	GTRB-01-7704B	Sulzer S3 Pump	7,910 hp ISO	Prior to 06/81
9	GTRB-51-8001A	Ruston TA 2500 Pump	2,500 hp ISO	Prior to 06/81
10	GTRB-51-8001B	Ruston TA 2500 Pump	2,500 hp ISO	Prior to 06/81
11	GTRB-51-8001C	Ruston TA 2500 Pump	2,500 hp ISO	Prior to 06/81
Group II: Gas –Fired Turbines				
12	H-51-8002A	Econotherm John Zink Burners	320 MMBtu/hr, LHV Heat Input	Prior to 1984
13	H-51-8002B			Prior to 1984
14	B-01-0001	Cleaver Brooks EG Boiler (Dual Fuel)	20.9 MMBtu/hr each, Heat Input, Lower Heating Value (LHV)	Prior to 12/81
15	B-01-0002			Prior to 12/81
16	B-01-0003			Prior to 08/78
17	B-01-0004			Prior to 08/78
18	B-01-0067	BS&B TEG Reboiler	8.2 MMBtu/hr, LHV Input	Modified October 1990
19	B-01-0068	BS&B TEG Reboiler		
20	B-01-9920	Smith TEG Reboiler	16.2 MMBtu/hr	1993
Group III: Liquid-Fired Equipment				
21	GNED-01-0001	Caterpillar D398 Emergency Generator	550 kW (737.6 hp)	After 1977
22	GNED-01-0002			
23	GNED-01-0011	Detroit Diesel Emergency Gen	550 kW	After 1977
24	PED-01-7004	Detroit Diesel Firewater Pump	280 hp	After 1977
25	GNED-01-8004	Detroit Diesel Emergency Gen	2,685 kW	After 1980
26	GTRB-51-8001	Alison 501KB Turbine Gen	5,000 hp	After 1980
Group IV - Flares				
27	FL-01-0001	KALDAIR LP/HP Vertical Emergency Flares	1.95 MMscf/day (pilot & purge gas)	Prior to November 1978
28	FL-01-0002			
29	FL-01-0003	KALDAIR LP/HP Vertical Emergency Flares		
30	FL-01-0004			
31	FL-01-0005	KALDAIR HP Vertical Emergency Flares		
32	FL-01-0006			
33	FL-01-0007			
34	FL-01-7001	BP Design Horizontal Burn Pit Emergency Flare		After 1980
35	FL-01-7002			
36	FL-01-9902	GBA/Corona HP Flare		1993
37	FL-01-9907	KALDAIR HP 1st Stage Flare		1993
Group V: Fixed Roof Storage Tanks With Capacity Greater Than 10,000 Gallons				
38	T-01-7703	Skim Oil / Oily Water Storage	493,500 gallons	1982
39	T-51-8008	Arctic #1 Diesel Storage Tank	252,000 gallons	1982
Well Pads D, E, F, G, K, P, and Y				

Table Notes:
Production and Injection Wells are typically grouped together on a gravel pad with their chokes and equipment enclosed in modules. BPXA refers to this collection of equipment on the gravel pad as a wellpad.

Appendix B: SO_2 Emissions from Fuel Gas Combustion

Determination of Projected Future H_2S Content of Fuel Gas

From the most recent actual measurements of the H2S content of the fuel gas, BPXA used sophisticated statistical analysis to project the future H_2S content of the fuel gas as 70 ppmv. Table B-1 presents the actual ppmv as reported in GC1's facility Operating Reports (FORs). The Department accepted BPXA's projected H_2S content of the fuel gas and included monitoring, recording, and reporting requirements that ensure SO_2 emission levels did not exceed levels that require a PSD permit.

Table B-1: H_2S Content of Fuel Gas at GC1 (ppmv)

Year	Maximum Average Concentration for Preceding 12 Months					Reference
	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual Average	
2000					12.5	Table I-c-5 of GC1 application
2001					14.0	
2002					11.7	
2003		10		10	10.8	Table I-c-5 and FORs for GC1
2004	10				13.3	
2005					15.0	Table I-c-5 of GC1 application
2006					18.6	
2007					28.5	
2008	25	25	25	25	24.0	Table I-c-5 and FORs for GC1
2009	25	25	25	25	24.7	
2010	28	26	26	26	25.3	
2011	23	23	22	22	23.0	FORs for GC1
2012	22					
Future					70	Table I-c-5

Table B-2: Fuel Gas Consumption at GC1 (MMscf)

Equipment	2004	2005	2006	2007	2008	2009	2010
Turbines	10,077	9,664	7,680	7,879	7,931	6,915	6,940
Heaters	1,153	1,196	1,446	1,462	1,506	1,441	1,383
Flares	580	721	504	458	550	567	534
Total	11,810	11,581	9,631	9,799	9,988	8,924	8,857

Table Notes:
Obtained from Table 1-c-3of Attachment I-c of application

Table B-3: Actual Fuel Gas Consumption and SO_2 Emissions

Year or Period	MMscf of Fuel Gas	ppmv H_2S in Fuel Gas	tpy SO_2 Emitted	tpy SO_2 Increase
2007	9,799	25 (permit limit)	20.7	
2008	9,988	24	20.2	
Baseline Actual			20.5	
Future Actual	9,440	70	58.7	38.2

Table Notes:
BPXA assumed future actual MMscf assumed as the five-year average consumption (2006 through 2010)
BPXA assumed a future actual H_2S content of 70 ppmv.
Increase in SO_2 emissions is 38.6 tpy and therefore project does not require PSD review.
tpy SO_2 = {[(9,440 MMscf) × (70 ppmv) ÷ (379.6 scf per mole)] × (64 lb SO_2 per mole H_2S) } ÷ (2,000 lb per ton)

Appendix C: SO_2 BACT Analysis for Emission Units 6, 7, and 8

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 fuel gas at GC1 will increase by 38 tpy. Because the existing H_2S limit in the fuel gas burned in EUs 6, 7, and 8 is treated as a Best Available Control Technology (BACT) limit, BPXA submitted a BACT analysis to support their request to increase the H_2S content of the fuel gas burned in EUs 6, 7, and 8 from 25 ppmv to 200 ppmv.

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 emissions increase 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 GC1 for the combustion of fuel gas in EUs 6, 7, and 8. The Department reviewed the BPXA's BACT analysis for GC1's EUs 6, 7, and 8 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 Prevention of Significant Deterioration 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 EUs 6, 7, and 8 follows in Section 3.

Section 3: BACT Determination for SO_2 for Fuel Gas Combustion in EUs 6, 7, and 8

BPXA is requesting a BACT limit of 200 ppmv H_2S content for the fuel gas burned in EUs 6, 7, and 8. The Department and BPXA estimate the potential-to-emit of SO_2 for the combustion of fuel gas in EUs 6, 7, and 8 as 68.1 tpy[2].

BPXA provided examples of fuel gas burning equipment in BPXA's BACT analysis that are similar to EUs 6, 7, and 8. The tables showed that controls identified in the RLBC 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 May 1, 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 two more (*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

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[2] Table 2-1 of BACT Analysis included in the application.

FGD systems, the flue gas reacts directly with lime to form solid calcium sulfate. The solid sulfates are collected in particulate control devices such as 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. Since the fuel gas-fired EUs 6, 7, and 8 will burn contain up to 200 ppmv H_2S and is considered a low sulfur, add-on FGD systems are not technically feasible for controlling SO_2 emissions from the combustion of fuel gas in EUs 6, 7, and 8.

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, biocide treatment are introduced as high dose slugs over an extended intervals 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. The liquid converts the H_2S 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. GC1 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 GC1.

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 at all times 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 GC1.

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, the Department believes it is not technically feasible for use at GC1.

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 GC3 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 GC1. Therefore, the ratio of CO_2 to H_2S and CO_2 partial pressure will even be higher at GC1.

BPXA determined that it is feasible at GC1 in spite of its own previous determinations that it was not feasible at the Central Gas Facility. The Department does not believe Shell-Paques is technologically feasible at GC1.

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. The adsorption process is technically feasible for controlling SO_2 emissions at GC1. Since the method of control is a 2-step process that involves adsorption followed by H_2S scavenging or the LO-CAT, the Department discarded it as not feasible. BPXA also determined, the adsorption process is not feasible at GC1.

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 EUs 6, 7, and 8 at GC1.

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 a 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 for the Kuparuk Seawater Treatment Plant in May 2004. 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 GC1 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 C-1 summarizes the options for controlling SO_2 emissions from fuel gas combustion at GC1.

Table C-1: Control Options for SO_2 Emissions and their Feasibility at GC1

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 GC1 unknown
Liquid Redox (LO-CAT)	3.1.3	Yes	Suits characteristics at GC1
H_2S Scavenging	3.1.4	Yes	Suits characteristics at GC1
Thiopaq	3.1.5	No	Line freezing problems in arctic, etc
Shell-Paques Technologies	3.1.5	Yes	Suits characteristics at GC1
Adsorption Process (Amine Treatment)	3.1.6	No	Requires follow-up LO-CAT, etc
Oxidation Process (Xergy ACT)	3.1.7	No	Safety concerns, GC1 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 C-2 lists and ranks the remaining technically feasible control technologies in order of effectiveness.

Table C-2: Technically Feasible SO_2 Control Options

Control Technology	Control Efficiency (%)
Liquid Redox (LO-CAT®)	99
Shell-Paques	99
H_2S Scavenging	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 H_2S content of the fuel gas burned in EUs 6, 7, and 8 at GC1 from 25 ppmv to 200 ppmv and potentially emit 68 tpy SO_2. Table C-1 summarized estimates for cost per ton SO_2 removed.

Liquid Redox (LO-CAT)

Table C-3 presents the costs for LO-CAT and the estimated cost effectiveness of LO-CAT. The Department estimates the cost per ton as $21,300 and considers it as excessive. Therefore, LO-CAT is not BACT for SO_2 control for EUs 6, 7, and 8 at GC1.

Table C-3: LO-CAT Costs and Estimated Cost Effectiveness for SO_2 Emissions in EUs 6-8

Description of Item and Costs	**BPXA**	**Department**
Equipment Costs		
Basic Equipment and Auxiliaries	1,206,329	1,206,329
Instrument and Controls	158,029	158,029
Module Materials	1,428,293	1,428,293
Spare Parts	24,127	24,127
Freight	322,090	322,090
Taxes (3 percent of above)	94,166	94,166
Total Equipment Cost (A)	*3,233,034*	*3,233,034*
Anchorage Construction Costs		
Erection and Handling	390,850	390,850
Instrumentation	49,459	49,459
Electrical	77,205	77,205
Piping	190,600	190,600
Insulation	16,889	16,889
Painting	7,238	7,238
Total Anchorage Construction Costs (B)	*732,241*	*732,241*
North Slope Construction Costs		
Foundations and Supports	8,444	8,444
Erection and Handling	77,205	77,205
Instrumentation	2,413	2,413
Electrical	6,032	6,032
Piping	37,396	37,396
Insulation	3,619	3,619
Painting	2,413	2,413
Total North Slope Construction Costs (C)	*137,522*	*137,522*
Total Direct Costs, D (D = A + B + C)	*4,102,797*	*4,102,797*
Indirect Costs		
Engineering and Procurement	229,202	229,202
Unit Operator Costs (UOC)	156,823	156,823
Start-up	Included with UOC	0
Performance Test (1.5% of Equipment Costs)	18,095	18,095
License Fee (Vendor Data)	593,000	Included in A
Total Indirect Costs, E	*611,095*	*404,120*
Total Direct Costs + Indirect Costs, F (F = D + E)	*5,099,917*	*4,506,917*

Contingency Costs (30 percent of F), G	*1,529,975*	*1,352,075*
Total Capital Costs, H (H = F + G)	*6,629,298*	*5,857,992*
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 (21 kW for 8,760 hr/yr @ $0.1 per kWh)	18,396	18,396
Chemicals	9,822	9,822
Total Direct Annual Costs	*307,005*	*307,005*
Total Indirect Annual Costs		
Overhead Costs (1 % of Total Capital Costs)	66,293	58,580
Property Tax (1 percent of Total Capital Costs)	66,293	58,580
Insurance (1 percent of Total Capital Costs)	66,293	58,580
General Administration (2 percent of Total Capital Costs)	132,586	117,160
Capital Recovery (Cost Recovery F * Total Capital Costs)	944,012	722,000
Total Annualized Indirect Costs	*1,275,477*	*1,014,900*
Total Annualized Direct and Indirect Costs	*1,582,482*	*1,321,905*
Cost Effectiveness for Removing 67.4 tons per year SO_2	**23,480**	**19,600**

Table Notes:
BPXA used 14.24% Cost Recovery Factor based on 7 percent interest and 10-year equipment life
Department used 12.33% Cost Recovery Factor based on 4 percent interest and 10-year equipment life
The LO-CAT system assumed to remove 67.4 (99% of the 68.1 tpy potential SO_2 Emissions)

Shell-Paques

Table C-4 presents the costs for Shell-Paques and the estimated cost effectiveness of Shell-Paques. The Department estimates the cost per ton as $21,300 and considers it as excessive. Therefore, Shell-Paques is not BACT for SO_2 control for EUs 6, 7, and 8 at GC1.

Table C-4: Shell-Paques Costs and Estimated Cost Effectiveness for SO_2 Emissions in EUs 6-8

Description of Item and Costs	**BPXA**	**Department**
Equipment Costs		
Basic Equipment and Auxiliaries	3,501,452	3,501,452
Instrument and Controls	458,690	458,690
Module Materials	4,145,719	4,145,719
Spare Parts	70,029	70,029
Freight	934,888	934,888
Taxes (3 percent of above)	273,323	273,323
Total Equipment Cost (A)	*9,384,101*	*9,384,101*
Anchorage Construction Costs		
Erection and Handling	1,134,470	1,134,470

Instrumentation	143,560	143,560
Electrical	224,093	224,093
Piping	553,229	553,229
Insulation	49,020	49,020
Painting	21,009	21,009
Total Anchorage Construction Costs (B)	*2,125,381*	*2,125,381*
North Slope Construction Costs		
Foundations and Supports	24,510	24,510
Erection and Handling	224,093	224,093
Instrumentation	7,003	7,003
Electrical	17,507	17,507
Piping	108,545	108,545
Insulation	10,504	10,504
Painting	7,003	7,003
Total North Slope Construction Costs (C)	*399,165*	*399,165*
Total Direct Costs, D (D = A + B + C)	*11,908,647*	*11,908,647*
Indirect Costs		
Engineering and Procurement	665,276	665,276
Unit Operator Costs (UOC)	455,189	455,189
Start-up	Included with UOC	Included with UOC
Performance Test (1.5% of Equipment Costs)	140,762	140,762
License Fee (Vendor Data)		
Total Indirect Costs, E	*1,261,227*	*1,261,227*
Total Direct Costs + Indirect Costs, F (F = D + E)	*13,169,874*	*13,169,874*
Contingency Costs (30 percent of F), G	*3,959,962*	*3,959,962*
Total Capital Costs, H (H = F + G)	*17,120,836*	*17,120,836*
Direct Annual Costs		
Operating Labor (730 hours @ $114 per hour)	79,570	79,570
Supervisory Labor (15 percent of operating labor)	11,936	11,936
Maintenance Labor (803 hours @ $109 per hour)	87,527	87,527
Parts and Materials (assumed as 100% of Maintenance)	87,527	87,527
Electricity (327,1561 kW for 8,760 hr/yr @ $0.1 per kWh)	21,156	21,156
Chemicals	7,717	7,717
Total Direct Annual Costs	*295,433*	*295,433*
Total Indirect Annual Costs		
Overhead Costs (1 % of Total Capital Costs)	171,208	171,208
Property Tax (1 percent of Total Capital Costs)	171,208	171,208
Insurance (1 percent of Total Capital Costs)	171,208	171,208
General Administration (2 percent of Total Capital Costs)	342,416	342,416
Capital Recovery (Cost Recovery F * Total Capital Costs)	2,438,007	2,110,999
Total Annualized Indirect Costs	*3,294,047*	*2,967,039*

Total Annualized Direct and Indirect Costs	*3,589,480*	*3,262,472*
Cost Effectiveness for Removing 67.4 tons per year SO_2	**53,256**	**48,404**

Table Notes:
BPXA used 14.24% Cost Recovery Factor based on 7 percent interest and 10-year equipment life
Department used 12.33% Cost Recovery Factor based on 4 percent interest and 10-year equipment life
The Shell-Paques system assumed to remove 67.4 (99% of the 68.1 tpy potential SO_2 Emissions)

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 $77,300 and for liquid scavenging as $45,000. The cost of removal for the H_2S scavenging system is prohibitive. The Department determined it is not BACT for SO_2 control at GC1.

Table C-5: Solid Scavenger Costs and Cost Effectiveness for SO_2 Emissions in EUs 6-8

Description of Item and Costs	**BPXA**	**Department**
Equipment Costs		
Basic Equipment and Auxiliaries	4,061,507	4,061,507
Instrument and Controls	532,057	532,057
Module Materials	4,808,825	4,808,825
Spare Parts	81,230	81,230
Freight	1,084,422	1,084,422
Taxes (3 percent of above)	3,170,412	3,170,412
Total Equipment Cost (A)	*13,738,453*	*13,738,453*
Anchorage Construction Costs		
Erection and Handling	1,315,928	1,315,928
Instrumentation	166,522	166,522
Electrical	259,936	259,936
Piping	641,718	641,718
Insulation	56,861	56,861
Painting	24,369	24,369
Total Anchorage Construction Costs (B)	*2,465,334*	*2,465,334*
North Slope Construction Costs		
Foundations and Supports	28,431	28,431
Erection and Handling	259,936	259,936
Instrumentation	8,123	8,123
Electrical	20,308	20,308
Piping	125,907	125,907
Insulation	12,185	12,185
Painting	8,123	8,123
Total North Slope Construction Costs (C)	*463,013*	*463,013*
Total Direct Costs, D (D = A + B + C)	*16,666,900*	*16,666,900*

Indirect Costs		
Engineering and Procurement	771,686	771,686
Unit Operator Costs (UOC)	527,996	527,996
Start-up	Included with UOC	Included with UOC
Performance Test (1.5% of Equipment Costs)	206,077	206,077
License Fee (Vendor Data)	0	0
Total Indirect Costs, E	*206,077*	*1,505,759*
Total Direct Costs + Indirect Costs, F (F = D + E)	18,172,659	18,172,659
Contingency Costs (30 percent of F), G	*5,451,798*	*5,451,798*
Total Capital Costs, H (H = F + G)	*23,624,451*	*23,624,451*
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)	45,771	45,771
Parts and Materials (assumed as 100% of Maintenance)	45,771	45,771
Chemicals (SulfaTreat XLP)	249,560	249,560
Media Replacement Labor	37,116	37,116
Media Disposal	30,000	30,000
Total Direct Annual Costs	*456,070*	*456,070*
Total Indirect Annual Costs		
Overhead (1% of Total Capital Costs)	236,245	236,245
Property Tax (1 percent of Total Capital Costs)	236,245	236,245
Insurance (1 percent of Total Capital Costs)	236,245	236,245
General Administration (2 percent of Total Capital Costs)	472,490	472,490
Capital Recovery (Cost Recovery F * Total Capital Costs)	3,364,122	2,060,000
Total Annualized Indirect Costs	*4,545,347*	*3,241,225*
Total Annualized Direct and Indirect Costs	*5,001,417*	*3,697,295*
Cost Effectiveness for Removing 64.7 tons per year SO_2	**77,302**	**57,100**

Table Notes:
BPXA used 14.24% Cost Recovery Factor based on 7 percent interest and 10-year equipment life
Department used 12.33% Cost Recovery Factor based on 4 percent interest and 10-year equipment life
The H_2S Scavenging system assumed to remove 64.7 tpy (95% of the 68.1 tpy potential SO_2 Emissions)

Table C-6: Liquid Scavenger Costs and Cost Effectiveness for SO_2 Emissions in EUs 6-8

Description of Item and Costs	**BPXA**	**Department**
Equipment Costs		
Basic Equipment and Auxiliaries	739,788	739,788
Instrument and Controls	96,912	96,912
Module Materials	875,909	875,909
Spare Parts	14,796	14,796
Freight	125,764	125,764

Taxes (3 percent of above)	555,951	555,951
Total Equipment Cost (A)	*2,409,120*	*2,409,120*
Anchorage Construction Costs		
Erection and Handling	239,691	239,691
Instrumentation	30,331	30,331
Electrical	47,346	47,346
Piping	116,886	116,886
Insulation	10,357	10,357
Painting	4,439	4,439
Total Anchorage Construction Costs (B)	*449,050*	*449,050*
North Slope Construction Costs		
Foundations and Supports	5,179	5,179
Erection and Handling	47,346	47,346
Instrumentation	1,480	1,480
Electrical	3,699	3,699
Piping	22,933	22,933
Insulation	2,219	2,219
Painting	1,480	1,480
Total North Slope Construction Costs (C)	*84,336*	*84,336*
Total Direct Costs, D (D = A + B + C)	*2,942,506*	*2,942,506*
Indirect Costs		
Engineering and Procurement	140,560	140,560
Unit Operator Costs (UOC)	96,172	96,172
Start-up	Included with UOC	Included with UOC
Performance Test (1.5% of Equipment Costs)	36,137	36,137
License Fee (Vendor Data)	0	---
Total Indirect Costs, E	*36,137*	*272,869*
Total Direct Costs + Indirect Costs, F (F = D + E)	*3,536,921*	*3,536,921*
Contingency Costs (30 percent of F), G	*1,061,076*	*1,061,076*
Total Capital Costs, H (H = F + G)	*4,607,997*	*4,607,997*
Direct Annual Costs		
Operating Labor (365 hours @ $114 per hour)	39,785	39,785
Supervisory Labor (15 percent of operating labor)	5,968	5,968
Maintenance Labor (402 hours @ $114 per hour)	87,527	87,527
Parts and Materials (assumed as 100% of Maintenance)	87,527	87,527
Chemicals (Scavenger @ $736 per day))	1,342,470	1,342,470
Desiccant ($250/day)	456,002	456,002
Total Direct Annual Costs	*2,019,279*	*2,019,279*
Total Indirect Annual Costs		
Overhead (1% of Total Capital Costs)	46,080	46,080

Property Tax (1 percent of Total Capital Costs)	46,080	46,080
Insurance (1 percent of Total Capital Costs)	46,080	46,080
General Administration (2 percent of Total Capital Costs)	92,160	92,160
Capital Recovery (Cost Recovery F * Total Capital Costs)	656,179	568,000
Total Annualized Indirect Costs	*886,579*	*798,400*
Total Annualized Direct and Indirect Costs	*2,905,858*	*2,817,679*
Cost Effectiveness for Removing 64.7 tpy SO_2	**44,913**	**43,500**

Table Notes
BPXA used 14.24% Cost Recovery Factor based on 7 percent interest and 10-year equipment life
Department used 12.33% Cost Recovery Factor based on 4 percent interest and 10-year equipment life
The H_2S Scavenging system assumed to remove 64.7 tpy (95% of the 68.1 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 summarized in Section 3.2.

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 cost of add-on controls per ton of SO_2 removed is unreasonably high. Therefore, the Department determined that BACT for control of the SO_2 emissions for combustion of fuel gas in EUs 6, 7, and 8 at GC1 is good practices with no add-on control, based on a not-to-exceed 200 ppmv H_2S content of the fuel gas.

Appendix D: Modeling Review Report

Modeling Review Report

State of Alaska
Department of Environmental Conservation
Division of Air Quality

Date: *July 30, 2012*

Project: *BPXA Gathering Center #1 Hydrogen Sulfide (H_2S) Limit Increase*

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 #1 (GC1). BPXA submitted this analysis in support of their February 2012 minor permit application (AQ0182MSS02). 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

GC1 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, GC1 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

GC1 is an existing PSD major source. BPXA is presently operating GC1 under Construction/Operating Permit AQ0182TVP01.

Fuel gas at GC1 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 AQ0182TVP01 on Emission Unit (EU) IDs 6, 7, and 8 (Tag Nos. GTRB-51-3304, GTRB-01-7704A, and GTRB-01-7704B, respectively). BPXA requests that the 25 ppmv consecutive 12-month average fuel gas H_2S BACT limit in Table 2 of permit no. AQ0182TVP01 for EU IDs 6, 7, and 8 be rescinded and replaced with a fuel gas H_2S BACT limit of 200 ppmv and the 25 ppmv consecutive 12-month average fuel gas H_2S limit in Condition 13 of permit no. AQ0182TVP01 for EU IDs 6, 7, and 8 be rescinded and replaced with a fuel gas H_2S limit of 125 ppmv or 200 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 GC1 Fuel Gas H_2S project, it is not clear whether BPXA needed to update their Air Quality Analysis and Additional Impact Analyses. BPXA took the safer approach of updating these aspects, in addition to the Source Impact Analysis, citing the U.S Environmental Protection Agency (EPA) guidance memo *Request for Determination on Best Available Control Technology (BACT) Issues - Ogden Martin Tulsa Municipal Waste Incinerator Facility*. This guidance contains language stating a more rigorous assessment of previously impacted standards should be conducted when modifying BACT limits. Rather than seeking further clarification regarding EPA's expectations in this type of situation, the Department instead proceeded with reviewing the entire submittal. The latter requirement for a Class I impact analysis was not warranted given the distance to the nearest Class I area.

SO_2 emissions are a precursor for particulate matter with an aerodynamic diameter of less than 2.5 microns (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; 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.

Project Submittal

BPXA submitted the 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 GC1 and located northeast of GC1 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* (µg/m^3)	AAAQS (µg/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 4.6 kilometers south of GC1, 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 GC1. 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 should 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 two separate operating scenarios at GC1 based on liquid fuel sulfur content. Based on previous modeling conducted for GC1, BPXA assumed that impacts from project emissions will exceed the modeling significance levels (SILs) listed in Table 5 of 18 ACC 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 GC1 emission units modeled at the proposed allowable emission rates for each of the 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 GC1 sources under consideration. Off-site sources included in the cumulative impact analysis for GC1 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 summary, BPXA's modeling approach for the SO_2 cumulative impact analysis is acceptable.

In addition to the requested permit revisions on H_2S limits at GC1, BPXA is simultaneously requesting similar revisions to H_2S limits at Gathering Center #2 (GC2), Gather Center #3 (GC3), and Flow Station #2 (FS2). Each of these sites is included as an off-site source in each of the GC1 operating scenarios. The modeling protocol included in Attachment IV of the application indicates SO_2 emissions for GC2, 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 GC1. 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 AQ0182TVP01. Emission units within GC1 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 at GC1 consist of both liquid and gas fired units. BPXA proposed and modeled two operating scenarios based on liquid fuel sulfur content. Each of the operating scenarios are 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 operating scenario, identified in the application as "Regular Liquid Sulfur Fuel limits the fuel sulfur content to 0.11 wt% sulfur for all liquid fuel-fired emission units at GC1. This scenario also limits the H_2S content of gas fuel to 125 ppmv for all gas-fired emission units at GC1, except EU IDs 6 through 8 (model IDs 1214, 1215, and 1219) which were modeled at 200 ppmv fuel gas H_2S per the proposed BACT limit.

The second scenario, "Ultra Low Sulfur Liquid Fuel," limits the liquid fuel sulfur content to 0.0015 wt%, also known as Ultra Low Sulfur Diesel (ULSD), for all liquid fuel-fired emission units at GC1. In this scenario, the fuel gas H_2S content is limited to 200 ppmv for all gas-fired emission units at GC1.

EUs 21 through 26 at GC1 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 – GC1 Operating Scenarios

Scenario	Fuel Gas H_2S Content (ppmv)	Liquid Fuel Sulfur Content (wt%)
Regular Liquid Sulfur Fuel	125*	0.11
Ultra Low Sulfur Liquid Fuel	200	0.0015

* 125 ppmv fuel gas H_2S content for all gas-fired emission units at GC1, except EU IDs 6 through 8 (model IDs 1214, 1215, and 1219) which were modeled at 200 ppmv fuel gas H_2S per the proposed BACT limit.

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 GC1 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 and 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 Liquid Sulfur Fuel[1]	1-hr	81	25	106	196
	3-hr	148	43	191	1,300
	24-hr	66	37	103	365
	Annual	7.1	4.1	11.2	80
Ultra Low Sulfur Liquid Fuel[2]	1-hr	81	25	106	196
	3-hr	155	43	198	1,300
	24-hr	66	37	103	365
	Annual	7.2	4.1	11.3	80

[1] 125 ppmv fuel gas H_2S (except EU IDs 6 through 8 modeled at 200 ppmv fuel gas H_2S) and 0.11 wt% liquid fuel sulfur

[2] 200 ppmv fuel gas H_2S and 0.0015 wt% liquid fuel sulfur

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 Liquid Sulfur Fuel	3-hr	134	512
	24-hr	66	91
	Annual	5.9	20
Ultra Low Sulfur Liquid Fuel	3-hr	155	512
	24-hr	66	91
	Annual	7.2	20

[1] 125 ppmv fuel gas H_2S (except EU IDs 6 through 8 modeled at 200 ppmv fuel gas H_2S) and 0.11 wt% liquid fuel sulfur

[2] 200 ppmv fuel gas H_2S and 0.0015 wt% liquid fuel sulfur

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 (11.3 $\mu g/m^3$) 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.

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

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.

CONCLUSION

The Department reviewed BPXA's modeling analysis for the GC1 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 analyses 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 AQ0182MSS02 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 SO_2 increment, the Permittee must comply with the existing 200 hour per year limit on EU IDs 21 through 26.

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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 thatdetails short-term emissions averaging.